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Hearing Room #5, Plaza Level

Commonwealth Keystone Building

400 North Street

Harrisburg, PA

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BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

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Section 53.51 et seq of the Commission's Regulations

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STATEMENT OF REASONS

UGI UTILITIES, INC. – GAS DIVISION
2026 Base Rate Case
Docket No. R-2025-3059523

STATEMENT OF REASONS

I. INTRODUCTION

UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") is filing Supplement No. 63 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S ("Supplement No. 63"), with a proposed effective date of March 29, 2026. The rates set forth in Supplement No. 63, if approved by the Pennsylvania Public Utility Commission ("Commission"), would increase UGI Gas's annual jurisdictional revenues by $99.368 million, or by 8.05%. Supplement No. 63 also proposes additional changes to tariff rates, riders, and tariff terms and conditions as described in the filing. The following rate impact analysis applies to UGI Gas's customers.

Average Residential Heating Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
68.7 ccf	$113.64	$123.55	$ 9.91	8.7%

Average Commercial Heating Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
26.8 Mcf	$336.74	$358.17	$ 21.43	6.4%

Average Industrial Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
54.6 Mcf	$647.57	$688.65	$ 41.07	6.3%

UGI Gas makes this tariff filing principally: (1) to allow it to earn a fair return on investments used and useful to serve the public safely and reliably; (2) to support ongoing Commission-approved infrastructure replacement programs designed to enhance safety and reliability; (3) to enhance information technology ("IT") systems; (4) to recover operating expenses necessary for the provision of safe and reliable gas distribution service; (5) to extend its Weather Normalization Adjustment ("WNA") pilot; for a second five year period; and (6) to incorporate a ten year normal weather calculation in its rate design. Each of these reasons is discussed in more detail below and in the Company's testimony. As compared to current plant and base rate levels reflected in existing rates, UGI Gas projects an increase of approximately $468 million in gross plant through the Fully Projected Future Test Year ending September 30, 2027 ("FPFTY"). Accordingly, this revenue increase is essential to attract the investments necessary to operate and maintain safe, reliable and customer-focused natural gas distribution services.

II. REASONS FOR THE REQUESTED REVENUE INCREASE

Fair return on investments used to serve the public

A variety of circumstances will prevent UGI Gas from earning a fair rate of return at present rate levels. As reflected in UGI Gas Exhibit A (Fully Projected), the Company's operations are under present rates projected to produce an overall return on rate base of 6.55%, which equates to a return on common equity of only 7.70% for the FPFTY. As explained by UGI Gas witness Dylan W. D'Ascendis (UGI Gas Statement No. 8), those returns are not adequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, its returns will decline. This will jeopardize its ability to attract capital necessary to support investments that ensure system reliability, safety, and quality customer service.

Support for Commission-approved infrastructure replacement programs

Significant capital investment in the distribution system is the primary driver for the requested rate relief in this proceeding. Upgrading and modernizing the distribution system facilitates the provision of safe, reliable, and reasonable service to customers. Accordingly, the Company is replacing its non-contemporary infrastructure at an accelerated pace, as described in the Company's Commission-approved Third Long Term Infrastructure Improvement Plan ("Third LTIIP").[1] Through the Third LTIIP, the Company will invest approximately $468 million through the FPFTY, which will strengthen and modernize distribution facilities, in part through its Commission-approved programmatic elimination of cast iron, bare steel and priority plastic mains on its system. In addition, UGI Gas continues to make system investments to serve new and existing residential and commercial customers, convert existing residences and commercial locations to natural gas (from other fuel sources), and improve critical information systems, as discussed in the Company's testimony.

Enhanced information technology systems, business processes and personnel effectiveness

The Company's IT projects involve hardware and software applications that will improve the Company's processes and methods across a wide range of operational needs, such as capital project management, cybersecurity, customer communications, and billing as well as other areas. Specifically, the Company is completing implementation of its Field Services Management ("FSM"). The FSM project will enhance the efficiency of planning, scheduling, dispatching, and completing field work, integrating directly with UGI Gas's existing UNITE technologies.

[1] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Third Long Term Infrastructure Improvement Plan*, Docket No. P-2024-3050769 (Opinion and Order entered December 5, 2024).

Operating expense increases

Since its last case, UGI Gas has diligently managed its operating expenses to mitigate the impact of increases on customers. However, this case does include a minor increase to operating and maintenance expense, as well as increases in other expenses incurred by the utility, such as the assessments from the Commission.

UGI Gas has made major strides toward modernizing its operations and has seen stable customer growth over time. However, the Company's continued significant investment in modernizing its system, certain cost increases, and changes in per customer usage, which are described in the Company's testimony, will produce an inadequate rate of return on investments at present rates.

Rate Design Methodology

A portion of the rate increase is a result of anticipated customer usage reductions under normal weather reflective of recent warming trends. The Company has historically used a 15 year normal weather calculation to support its rate design for distribution rates and will now reflect a 10 year normal weather calculation. This change will impact both its distribution rates and the WNA. These changes are described in the testimony of UGI Gas witness John D. Taylor (UGI Gas Statement No. 11).

The identified initiatives and efforts, as described by the Company's witnesses, demonstrate UGI Gas's commitment to providing safe, reliable, and quality distribution service to its customers. The Company believes that its management efforts, system investments, and continued provision of safe and reliable service at reasonable rates, as detailed by the witnesses' testimony submitted in this case, all support the Company's requested rate of return, including its request for 10.75% return on common equity as discussed in the Direct Testimony of Dylan W. D'Ascendis (UGI Gas Statement No. 8).

III. OVERVIEW OF FILING

Included with UGI Gas's filing are all of the supporting data required by the Commission's regulations. This information provides data for an historic test year ended September 30, 2025 ("HTY"), a future test year ("FTY") ending September 30, 2026, and a FPFTY. In accordance with permitted ratemaking procedures, the Company has elected to use the FPFTY as the basis for its proposed revenue change.

UGI Gas has followed Commission ratemaking practice in preparing its claims for plant additions, rate base, operating revenues and operating expenses.

Capital Planning. The total budgeted plant additions for the FPFTY are made up of four main categories: (1) replacement and betterment infrastructure; (2) new business; (3) IT; and (4) other capital spending. The Direct Testimony of UGI Gas witness Vicky A. Schappell provides support for the Company's FPFTY plant additions.

Rate Base. Rate base was determined based on depreciated original cost values for projected plant in service at the end of the FTY and FPFTY, respectively. The Company's rate base claim also includes reasonable estimates for materials and supplies inventory and cash working capital, as well as standard deductions for accumulated depreciation, accumulated deferred income taxes, and customer deposits. The Company's rate base claim is shown in summary form in Schedule C-1 to Exhibit A (Fully Projected) and is principally supported by the Direct Testimony of Amy M. Keller (UGI Gas Statement No. 5).

Operating Revenues. UGI Gas's *pro forma* test year operating revenues were derived from its fiscal year 2025 operating budget. As explained in the testimony of Sherry A. Epler (UGI Gas Statement No. 10) and other witnesses, operating revenues were annualized, normalized, and

otherwise adjusted in accordance with standard ratemaking practice, as detailed in Schedules D-5 and D-5A of Exhibit A (Fully Projected) and the exhibits attached to Ms. Epler's testimony.

Operating Expenses. UGI Gas's *pro forma* test year operating expenses were derived from its fiscal year 2025 operating budget. As explained in the testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2) and other witnesses, certain operating expenses were annualized, normalized, and otherwise adjusted in accordance with standard ratemaking practice, as detailed in Section D of Exhibit A (Fully Projected). UGI Gas's claim for depreciation and amortization expense is supported by Exhibit C (Fully Projected) to the filing, and exhibits developed and supported by John F. Wiedmayer of Gannett Fleming Valuation & Rate Consultants, LLC (UGI Gas Statement No. 6). Mr. Wiedmayer's calculations are based on the straight-line, remaining life method previously approved for UGI Gas's operations by the Commission.

Income Taxes. UGI Gas's income tax expense was calculated using procedures previously accepted by the Commission. The Company's filing reflects the normalization of book-tax timing differences related to the use of accelerated depreciation for federal tax purposes and for the Company's repairs allowance deductions. As it relates to accelerated depreciation for state tax purposes, the Company uses flow-through for rate making purposes. The Company's tax claims are described and supported in the Direct Testimony of Darin T. Espigh (UGI Gas Statement No. 9).

Rate Design, Revenue Allocation and Class Cost of Service. UGI Gas is proposing to allocate the revenue requirement to all customer classes based on the results of a consolidated class cost of service study. The Company's proposed revenue allocation will move all rate classes substantially toward the overall system average rate of return. UGI Gas is also proposing to renew its WNA pilot for another five year period with certain modifications. Additional details regarding

the Company's cost of service study, revenue allocation, and WNA proposal are provided in the Direct Testimony of John D. Taylor (UGI Gas Statement No. 11).

Other Tariff Changes. In this filing, the Company proposes relatively few changes to the terms and conditions approved by the Commission in the Company's most recent completed rate case. A list of all proposed changes is identified in the Company's proposed tariff, Supplement No. 63 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S.

Customer Assistance and Affordability. The Company will contribute $1,000,000 annually for fiscal years 2027 to 2029 to its Operation Share Energy Fund. This contribution will assist low- and moderate-income customers with income levels up to 250% of the Federal Poverty Income Guidelines. Through Operation Share, energy assistance grants of up to $600 are provided to eligible customers who require assistance paying their heating bills. This funding for Operation Share is a donation from UGI that is not recoverable from or included in rates.

IV. CONCLUSION

The proposed revenue increase is the minimum increase necessary for UGI Gas to continue providing safe and reliable service, to maintain the integrity of its financial ratings, to attract additional capital on reasonable terms, and to have a reasonable opportunity to earn a fair rate of return on property that is used and useful in providing natural gas service to the public within its service territory. The proposals contained in this filing will provide significant benefits to all stakeholders. Moreover, the Company's proposed revenue allocation and rate design are just and reasonable and non-discriminatory, as are the proposed changes made to the Company's general terms and conditions of service. Therefore, the rates, rules, and terms and conditions of service set forth in Supplement No. 63 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S should be permitted to become effective as filed.

PLAIN LANGUAGE - STATEMENT OF REASONS

UGI UTILITIES, INC. – GAS DIVISION
2026 Base Rate Case
Docket No. R-2025-3059523

PLAIN LANGUAGE STATEMENT OF REASONS

UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") has asked the Pennsylvania Public Utility Commission ("PUC" or the "Commission") to increase UGI Gas's annual jurisdictional revenues by $99.368 million, or by 8.05%. The percentage rate increase will vary by rate class. The main reasons for this proceeding are:

- UGI Gas maintains investments in gas plant needed to provide continued safe and reliable service with plans to spend approximately $468 million in gross plant through 2027.

- Without substantial rate relief, UGI Gas will not be able to earn a fair return on its investment used to serve the public and, if not addressed, this could adversely affect the integrity of its financial ratings, increasing the cost of future safety work, potentially impacting its ability to provide safe and reliable service to its customers.

- UGI Gas proposes to extend its Weather Normalization Adjustment ("WNA") pilot for an additional 5 year period with certain modifications, which will continue to stabilize the impacts of weather variances during the heating season and permit the Company a reasonable opportunity to recover the costs of providing natural gas service for its customers.

UGI Gas designed the proposed rates for each customer class to recover its total required revenue while considering affordability impacts to customers. In allocating the revenue increase to the residential and non-residential customer classes, UGI Gas was guided by detailed studies of each rate class's cost of service. UGI Gas also considered and balanced other principles of rate design consistent with the Commission's approach to ratemaking. Furthermore, the Company will contribute $1,000,000 annually for fiscal

years 2027 to 2029 to its Operation Share program. This donation will assist qualified customers in receiving up to $600 in assistance in paying their energy bills.

Along with its rate increase, UGI Gas has filed all of the supporting data required by the Commission's regulations, as well as the written statements of twelve witnesses and numerous exhibits prepared by those witnesses. The data, testimony, and exhibits submitted by UGI Gas comply with the Commission's filing requirements. The proposed distribution revenue increase is the minimum increase necessary for UGI Gas to continue providing safe and reliable service to the public within its service territory.

SECTION 53.52 - FILING REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION

Proposed Changes to UGI Utilities, Inc. – Gas Division, Supplement No. 63 to Original Tariff Nos. 7 and 7S

Information furnished with the filing of rate changes under
52 Pa. Code, Section 53.52

(a) Applicable to changes in terms and conditions of service.

(a)(1) The specific reason for each change.

The Company has provided a Statement of Reasons describing the necessity for the changes proposed in this filing.

(a)(2) The total number of customers served by the utility.

706,232 customers as of September 30, 2025.

(a)(3) A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

R/RT	634,252
N/NT	69,690
DS	1,305
LFD	638
XD	37
IS	292

(a)(4) The effect of the change on the utility's customers.

The specific effect by class is shown in UGI Gas Exhibit E – Proof of Revenue.

(a)(5) The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The Company's proposal will change revenue and expenses, as shown on UGI Gas Exhibit A (Fully Projected), Schedule A-1. Individual adjustments to revenues and expenses are described in testimony and exhibits supporting the filing.

(a)(6) The effect of the change on the service rendered by the utility.

The filing will allow the Company to continue to provide safe and reliable service to its customers while maintaining high levels of customer satisfaction.

(a)(7) A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement as to why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa.C.S. Section 1308 (relating to voluntary changes in rates).

The Company has provided a Statement of Reasons describing the numerous factors considered in its determination to make the filing. Please also see the Direct Testimony of Hans G. Bell (UGI Gas Statement No. 1) for a summary of those factors.

(a)(8) Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa.C.S. Section 1308.

Not applicable.

(a)(9) Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

The Company has not undertaken any polls.

(a)(10) Plans the utility has for introducing or implementing the change with respect to its customers.

The Company will notify customers of the proposed changes, including the modifications proposed to the existing Weather Normalization Adjustment alternative ratemaking mechanism by a bill insert using the form of notices specified by the Commission at 52 Pa. Code 53.45. A copy of the notice will be provided together with an affidavit of compliance with the notice requirements. In addition, the Company will issue a press release and paid advertisements on the date of filing as well as posting notices at the Company's headquarters and website at https://www.ugi.com/notices/.

(a)(11) F.C.C. or FERC or Commission orders or rulings applicable to the filings.

No F.C.C., FERC or Commission orders or rulings apply to this filing.

(b) Applicable to changes in rates.

(b)(1) Specific reason for each change.

The Company has provided a Statement of Reasons describing the necessity of this filing. In addition, please see the Direct Testimony of Hans G. Bell, UGI Gas Statement No. 1, Sherry A. Epler, UGI Gas Statement No. 10, and John D. Taylor, UGI Gas Statement No. 11.

(b)(2) Utility's operating income statement ending not more than 120 days prior to filing date – historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule B-2. For future test year and fully projected future test year operating income statements, please refer to UGI Gas Exhibit A (Future), Schedule B-2, and UGI Gas Exhibit A (Fully Projected), Schedule B-2.

(b)(3) Number of customers, by tariff subdivision, whose bills will be increased.

Tariff Rate	Customers
R/RT	634,252
N/NT	69,690
DS	1,305
LFD	638

(b)(4) Total increases, in dollars, by tariff subdivision, projected to an annual basis.

Please refer to UGI Gas Exhibit E – Proof of Revenue.

(b)(5) Number of customers, by tariff subdivision, whose bills will be decreased.

Tariff Rate	Customers
XD	37
IS	292

(b)(6) Total decreases, in dollars, by tariff subdivision, projected to an annual basis.

Please refer to UGI Gas Exhibit E – Proof of Revenue.

(c) Applicable to changes where increase for any tariff subdivision exceeds 3% of utility's operating revenue OR bills of more than 5% of customers will increase.

(c)(1) Rate of return for historic year and anticipated for future year.

Please refer to UGI Gas Exhibit A (Historic), Schedule A-1, UGI Gas Exhibit A (Future), Schedule A-1, and UGI Gas Exhibit A (Fully Projected), Schedule A-1.

(c)(2) Detailed balance sheet at the end of the historic year.

For the end of the historic year balance sheet, please refer to UGI Gas Exhibit A (Historic), Schedule B-1.

(c)(3) Summary, by detailed plant accounts, of book value of property of utility at end of historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule C-2, for the original cost book value of the property of the utility for the historic year.

(c)(4) Respective amount of the depreciation reserve applicable to each detailed plant account.

Please refer to UGI Gas Exhibit A (Historic), Schedule C-3, for the historic year depreciation reserve as of year-end, UGI Gas Exhibit A (Future), Schedule C-3, for the future test year depreciation reserve as of year-end, and UGI Gas Exhibit A (Fully Projected), Schedule C-3, for the fully projected future test year depreciation reserve as of year-end.

(c)(5) Statement of operating income, setting forth the operating revenues and expenses by detailed accounts – historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule B-2, for the historic year operating revenue and expenses.

(c)(6) Description of any major changes in the operating or financial condition of the utility occurring between the date of the balance sheet at end of the historic year and filing date.

None.

SECTION 53.62 - FILING REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION

Proposed Supplement No. 63 to UGI Gas Tariff Nos. 7 and 7S

Information furnished pursuant to 52 Pa. Code, Section 53.62

§ 53.62. Additional information to be filed by gas utilities with gross annual intrastate operating revenues in excess of $40 million seeking a change in base rates.

In addition to information otherwise required to be filed by a jurisdictional natural gas distributor with gross intrastate annual operating revenues in excess of $40 million seeking a change in its base rates, each gas utility shall also file updates to the information required by § 53.64(c) (relating to filing requirements for natural gas distributors with gross intrastate annual operating revenues in excess of $40 million). In the case of a gas utility purchasing gas as defined at § 53.61(a) (relating to purpose) from an affiliated interest, it shall also file updates to the information required at § 53.65 (relating to special provisions relating to natural gas distributors with gross intrastate annual operating revenues in excess of $40 million with affiliated interests). These updates shall be made at the time the base rate case under 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) is originally filed. Deficiencies in filing will be treated as set forth at § 53.51(c) (relating to general).

RESPONSE:

Please see the response to III-E-30.

SECTION 53.53 - VALUATION

I-A-1

Request:

Provide a corporate history (include the dates of original incorporation, subsequent mergers and/or acquisitions). Indicate all counties and cities and other governmental subdivisions to which service is provided (including service areas outside the state), and the total population in the area served.

Response:

UGI Utilities, Inc. began its modern corporate existence as part of a consolidation of a number of predecessor natural gas and electric public utilities into The United Gas Improvement Company, as approved by the Pennsylvania Public Utility Commission ("Commission") on June 16, 1952 at Docket No. A.78264. In 1968, The United Gas Improvement Company changed its name to UGI Corporation. In 1971, UGI Corporation's gas operations were consolidated into a gas division ("UGI Gas") located in Reading, Pennsylvania. In January 2019, UGI Gas relocated its headquarters to Denver, Pennsylvania. UGI Corporation's electric operations ("UGI Electric") operates in a separate electric division headquartered in northeastern Pennsylvania. In 1992, as part of a further corporate restructuring, UGI Corporation changed its name to UGI Utilities, and became a wholly-owned subsidiary of a new holding company which adopted the name UGI Corporation.

UGI Utilities, Inc. increased its gas operations in 2006 and 2008 with the incorporation of two subsidiary gas utilities – UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), respectively. UGI PNG began its operations following the close, on August 24, 2006, of UGI Corporation's purchase of the natural gas distribution assets from the former PG Energy Division of Southern Union Company, as authorized by a Commission Order entered on August 18, 2006, at Docket No. A-120011F200. UGI CPG, formerly PPL Gas Utilities Corporation ("PPL Gas"), was acquired by UGI Utilities effective October 1, 2008, as authorized by a Commission Order entered on August 21, 2008, at Docket Nos. A-2008-2034045, et al. Prior to that acquisition, PPL Gas itself was the result of several mergers and acquisitions authorized by the Commission. See, e.g., Joint application of PPL Gas Utilities Corp., North Penn Gas Company, and PFG Gas, Inc., Docket Nos. A-125127, et al. (Order entered July 12, 2004); Application of Allied Gas Company, et al., Docket No. A-120650F002 (order approving merger and restructuring entered January 27, 1995).

I-A-1 (Continued)

In accordance with authority granted in a Commission Opinion and Order entered on September 20, 2018 at Docket Nos. A-2018-3000381 et seq., UGI PNG and UGI CPG merged into UGI Gas effective October 1, 2018. The former service territories of UGI PNG, UGI Gas and UGI CPG were organized into the North, South and Central Rate Districts of UGI Gas, respectively. By a Commission Opinion and Order entered on October 4, 2019 at Docket Nos. R-2018-3006814 et seq., the Commission approved UGI Gas's proposal to eliminate the Rate District structure and move most rate classes to uniform distribution rates for a single UGI Gas service territory encompassing the aggregate service territory of the former North, South, and Central Rate Districts.

The list of communities served by UGI Gas is set forth in its tariff provided in this rate filing and which is available on the Commission's website at: https://www.puc.pa.gov/filing-resources/tariffs/natural-gas-tariffs/. UGI Gas provides natural gas distribution service to approximately 706,000 residential, commercial and industrial natural gas customers located in 46 of Pennsylvania's total 67 counties and spanning more than 700 municipalities. The populations for each of the municipalities served, based on U.S. census data, is available at the Penn State Pennsylvania State Data Center website at: https://pasdc.hbg.psu.edu/data/resources/2021-county-population-estimates

UGI Gas also provides natural gas service to approximately 500 customers in one Maryland County under authority granted by the Maryland Public Service Commission.

UGI Electric can trace its origins to the 1925 acquisition by UGI of the American Gas Co., which owned the Luzerne County Gas and Electric Corporation. In 1953, as authorized by a Certificate of Public Convenience issued by the Commission on June 16, 1952, at Docket No. A.78264, all of UGI's Pennsylvania public utility subsidiaries, including the Luzerne County Gas and Electric Company, were merged into UGI. In 1967, UGI acquired the Harveys Lake Light Company, whose 113 square mile service territory, along with the electric service territory of the former Luzerne County Gas and Electric Corporation, comprise UGI Electric's current service territory. UGI Electric provides electric distribution service to approximately 63,000 residential, commercial, and industrial electric customers in Luzerne and Wyoming Counties and 35 municipalities.

Prepared by or under the supervision of: Hans G. Bell

I-A-2

Request:

Provide a schedule showing the measures of value and the rates of return at the original cost and trended original cost measures of value at the spot, three-year and five-year average price levels. All claims made on this exhibit should be cross-referenced to appropriate exhibits. Provide a schedule similar to the one listed above, reflecting respondent's final claim in its previous rate case.

Response:

The Company's claim is based on original cost measures of value. Since Pennsylvania state law mandates the use of original cost for ratemaking, a trended cost study was not prepared.

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule A-1.

Refer to Attachment I-A-2 for similar schedules from the previous rate case.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2024 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 5,432,684		$ 5,432,684
2	Accumulated Depreciation		C-3	(1,424,341)		(1,424,341)
3	Net Plant in service	L 1 + L 2		4,008,343	-	4,008,343
4	Working Capital		C-4	56,262		56,262
5	Gas Inventory		C-5	19,462		19,462
6	Accumulated Deferred Income Taxes		C-6	(653,768)		(653,768)
7	Customer Deposits		C-7	(22,616)		(22,616)
8	Materials & Supplies		C-8	31,924		31,924
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 3,439,607	$ -	$ 3,439,607
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 748,660	$ (15,829)	$ 732,831
11	Gas Cost Revenue		D-5	304,854		304,854
12	Other Operating Revenues		D-5	16,211		16,211
13	Total Revenues	Sum L 10 to L 12		1,069,725	(15,829)	1,053,896
14	Operating Expenses		D-1	(714,308)	276	(714,031)
15	OIBIT	L 13 + L 14		355,417	(15,553)	339,864
16	Pro Forma Income Tax at Present Rates		D-33	(64,939)		
17	Pro Forma Income Tax on Revenue Increase		D-33		4,370	(60,569)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 290,478	$ (11,182)	$ 279,295
19	RATE OF RETURN	L 18 / L 9		8.4451%		8.1200%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		8.4451%		
21	Rate of Return Required		B-7	8.1200%		
22	Change in ROR	L 21 - L 20		-0.3251%		
23	Change in Operating Income	L 22 * L 9		$ (11,182)		
24	Gross Revenue Conversion Factor		D-35	1.415576		
25	Change in Revenues	L 23 * L 24		$ (15,829)		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 3			-2.11%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 3			-1.48%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2025 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 5,795,922		$ 5,795,922
2	Accumulated Depreciation		C-3	(1,509,517)		(1,509,517)
3	Net Plant in service	L 1 + L 2		4,286,405	-	4,286,405
4	Working Capital		C-4	61,905		61,905
5	Gas Inventory		C-5	19,462		19,462
6	Accumulated Deferred Income Taxes		C-6	(676,532)		(676,532)
7	Customer Deposits		C-7	(22,616)		(22,616)
8	Materials & Supplies		C-8	31,924		31,924
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 3,700,548	$ -	$ 3,700,548
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 765,240	$ 36,186	$ 801,426
11	Gas Cost Revenue		D-5	355,958		355,958
12	Other Operating Revenues		D-5	14,826		14,826
13	Total Revenues	Sum L 10 to L 12		1,136,025	36,186	1,172,211
14	Operating Expenses		D-1	(804,872)	(632)	(805,504)
15	OIBIT	L 13 + L 14		331,152	35,554	366,707
16	Pro Forma Income Tax at Present Rates		D-33	(56,370)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(9,851)	(66,221)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 274,782	$ 25,704	$ 300,486
19	RATE OF RETURN	L 18 / L 9		7.4254%		8.1200%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		7.4254%		
21	Rate of Return Required		B-7	8.1200%		
22	Change in ROR	L 21 - L 20		0.6946%		
23	Change in Operating Income	L 22 * L 9		$ 25,703		
24	Gross Revenue Conversion Factor		D-35	1.407844		
25	Change in Revenues	L 23 * L 24		$ 36,186		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 3			4.73%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 3			3.19%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2026 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 6,218,576		$ 6,218,576
2	Accumulated Depreciation		C-3	(1,618,836)		(1,618,836)
3	Net Plant in service	L 1 + L 2		4,599,741	-	4,599,741
4	Working Capital		C-4	62,726		62,726
5	Gas Inventory		C-5	19,462		19,462
6	Accumulated Deferred Income Taxes		C-6	(687,743)		(687,743)
7	Customer Deposits		C-7	(22,616)		(22,616)
8	Materials & Supplies		C-8	31,924		31,924
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 4,003,493	$ -	$ 4,003,493
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 768,792	$ 110,395	$ 879,187
11	Gas Cost Revenue		D-5	357,259		357,259
12	Other Operating Revenues		D-5	14,836		14,836
13	Total Revenues	Sum L 10 to L 12		1,140,887	110,395	1,251,282
14	Operating Expenses		D-1	(837,064)	(1,927)	(838,992)
15	OIBIT	L 13 + L 14		303,822	108,468	412,290
16	Pro Forma Income Tax at Present Rates		D-33	(45,571)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(29,625)	(75,196)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 258,251	$ 78,843	$ 337,094
19	RATE OF RETURN	L 18 / L 9		6.4507%		8.4200%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		6.4507%		
21	Rate of Return Required		B-7	8.4200%		
22	Change in ROR	L 21 - L 20		1.9694%		
23	Change in Operating Income	L 22 * L 9		$ 78,843		
24	Gross Revenue Conversion Factor		D-35	1.400192		
25	Change in Revenues	L 23 * L 24		$ 110,395		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 3			14.36%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 3			9.68%	

I-A-3

Request:

Provide a description of the depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of all factors which were considered in arriving at estimates of service life and dispersion by account. Provide dates of all field inspections and facilities visited.

Response:

The depreciation methods used in calculating annual and accrued depreciation and the factors considered in service life estimation are discussed in Exhibit C (Future) in “Part II. Methods Used in the Determination of Annual and Accrued Depreciation” and Part III. Service Life Considerations”. There have been no changes in the survivor curve estimates nor the method of depreciation. These are the same survivor curve estimates and method of depreciation as filed in the company’s most recent service life study report to the Pennsylvania Public Utility Commission, Docket No. M-2023-3041044.

Field trips and facilities visited are presented in Exhibit C (Future) in Part III in the section titled "Field Trips," beginning on page III-2.

Prepared by or under the supervision of: John F. Wiedmayer

I-A-4

Request:

Set forth, in exhibit form, charts depicting the original and estimated survivor curves and a tabular presentation of the original life table plotted on the chart for each account where the retirement rate method of analysis is utilized.

a. If any utility plant was excluded from the measures of value because it was deemed not to be "used and useful" in the public service, supply a detailed description of each item of property.

b. Provide the surviving original cost at test year end by vintage by account and include applicable depreciation reserves and annuities.

   (i) These calculations should be provided for plant in service as well as other categories of plant, including, but not limited, to contributions in aid of construction, customers' advances for construction, and anticipated retirements associated with any construction work in progress claims (if applicable).

Response:

Charts depicting the original and estimated survivor curves and a tabular presentation of the original life table plotted on the chart for each account where the retirement rate method of analysis was utilized is presented in Exhibit C (Future) in Part VI of the report.

a. No utility plant recorded in Account 101, Gas plant in Service, was excluded from the measures of value. However, gas plant owned by UGI Utilities, Inc. that serve approximately 500 Maryland customers in Frederick County near the Pennsylvania-Maryland state border were excluded from this filing. The depreciation reserve and depreciation associated with Maryland gas plant also were excluded from this filing.

b. The surviving original cost at the end of the historical year September 30, 2025, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Historic). The tabulations are presented in Part III of the report in the section titled "Depreciation Calculations."

I-A-4 (Continued)

The surviving original cost at the end of the future test year September 30, 2026, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Future). The tabulations are presented in Part VII of the report in the section titled "Depreciation Calculations."

The surviving original cost at the end of the fully projected future test year September 30, 2027, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Fully Projected). The tabulations are presented in Part III of the report in the section titled "Depreciation Calculations."

Prepared by or under the supervision of: John F. Wiedmayer

I-A-5

Request:

Provide a comparison of respondent's calculated depreciation reserve v. book reserve by account at the end of the test year.

Response:

Comparisons of the calculated accrued depreciation v. the book reserve at the end of each test year are set forth in Attachment I-A-5.

Prepared by or under the supervision of: John F. Wiedmayer

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2025

ACCOUNT		CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
(1)		(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	23,039
TOTAL PRODUCTION PLANT		**0**	**23,039**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	558,250	571,904
366	STRUCTURES AND IMPROVEMENTS	135,472	156,695
367	MAINS	18,730,520	23,115,954
369	MEASURING AND REGULATING STATION EQUIPMENT	3,709,675	4,255,146
370	COMMUNICATION EQUIPMENT	2,003,839	2,462,642
371	OTHER EQUIPMENT	119,842	133,053
371.1	TESTING EQUIPMENT	162,418	167,850
TOTAL TRANSMISSION PLANT		**25,420,016**	**30,863,244**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,347,013	1,508,064
375	STRUCTURES AND IMPROVEMENTS	3,105,893	3,577,081
376.1	MAINS - PRIMARILY STEEL	202,930,167	202,628,288
376.2	MAINS - CAST IRON	619,945	605,269
376.3	MAINS - PLASTIC	358,303,989	359,244,271
376.5	MAINS - PRIMARILY WROUGHT IRON	263,180	255,480
376.7	REG AFUDC	148,735	267,172
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	38,808,361	41,528,725
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	13,468,366	13,438,274
380	SERVICES	484,137,914	460,225,389
381	METERS	58,584,262	64,992,744
381.1	METERS - ERTS	21,541,307	17,039,782
382	METER INSTALLATIONS	44,182,159	47,684,946
383	HOUSE REGULATORS	5,758,207	3,921,107
384	HOUSE REGULATOR INSTALLATIONS	8,090,599	9,463,445
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	17,610,193	19,978,680
386	OTHER PROPERTY ON CUSTOMERS PREMISES	47,409	(55,879)
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	598,019	706,337
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	23,376	24,720
387	OTHER EQUIPMENT	2,670,116	3,225,607
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,479,419	1,481,718
TOTAL DISTRIBUTION PLANT		**1,263,718,629**	**1,251,741,220**

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2025

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	47,302,497	49,470,174
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	2,158,301	1,973,088
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	126,300	122,642
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	4,842,879	4,391,081
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,378,298	4,333,192
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	3,310,654	3,667,639
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	15,948,496	16,378,755
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	2,263,473	2,777,810
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	15,930,834	18,137,557
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL	2,738,441	3,144,919
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	3,369,469	3,935,541
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	1,036,864	1,191,005
393	STORES EQUIPMENT	7,057	7,057
394	TOOLS, SHOP AND GARAGE EQUIPMENT	16,765,817	16,560,440
395	LABORATORY EQUIPMENT	184,838	178,472
396	POWER OPERATED EQUIPMENT	4,738,789	5,174,132
397	COMMUNICATION EQUIPMENT	1,018,276	825,767
398	MISCELLANEOUS EQUIPMENT	929,243	1,055,236
399	OTHER TANGIBLE PROPERTY	16,032	16,032
TOTAL GENERAL PLANT		**127,066,558**	**133,340,539**
TOTAL DEPRECIABLE GAS PLANT		**1,416,205,203**	**1,415,968,042**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	7,091,968	7,318,564
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,315,179	1,407,352
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	968,738	748,671
TOTAL COMMON PLANT		**9,375,885**	**9,474,587**
INFORMATION SERVICES (IS)			
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	6,433,263	5,819,410
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	7,289,157	6,623,801
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	34,670,326	35,342,141
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	66,727,274	65,398,509
TOTAL INFORMATION SERVICES		**115,120,020**	**113,183,861**
TOTAL OTHER UTILITY PLANT		**124,495,905**	**122,658,448**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2026

ACCOUNT		CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
(1)		(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0
TOTAL PRODUCTION PLANT		**0**	**0**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	567,780	583,277
366	STRUCTURES AND IMPROVEMENTS	137,226	156,987
367	MAINS	19,154,790	23,526,057
369	MEASURING AND REGULATING STATION EQUIPMENT	3,796,591	4,347,592
370	COMMUNICATION EQUIPMENT	2,084,205	2,549,221
371	OTHER EQUIPMENT	121,223	133,995
371.1	TESTING EQUIPMENT	166,786	172,428
TOTAL TRANSMISSION PLANT		**26,028,601**	**31,469,557**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,388,075	1,551,251
375	STRUCTURES AND IMPROVEMENTS	3,217,843	3,693,851
376.1	MAINS - PRIMARILY STEEL	211,609,357	211,746,999
376.2	MAINS - CAST IRON	642,089	664,766
376.3	MAINS - PLASTIC	389,327,222	390,033,008
376.5	MAINS - PRIMARILY WROUGHT IRON	265,200	261,046
376.7	REG AFUDC	181,787	300,224
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	42,816,694	46,205,293
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	15,498,095	16,033,091
380	SERVICES	511,798,093	485,016,289
381	METERS	61,227,396	67,493,856
381.1	METERS - ERTS	22,722,444	19,347,248
382	METER INSTALLATIONS	46,806,851	50,079,255
383	HOUSE REGULATORS	5,915,430	5,133,343
384	HOUSE REGULATOR INSTALLATIONS	8,406,649	9,800,803
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	18,352,569	21,130,913
386	OTHER PROPERTY ON CUSTOMERS PREMISES	42,315	42,958
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	623,434	632,918
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	23,582	24,705
387	OTHER EQUIPMENT	2,772,317	3,316,734
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,483,885	1,485,147
TOTAL DISTRIBUTION PLANT		**1,345,121,327**	**1,333,993,698**

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2026

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	52,571,730	55,336,908
390.3	CNG STATIONS	251,410	251,058
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	2,430,307	2,231,975
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	99,327	89,606
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	7,343,612	7,096,550
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAR	2,121,380	2,343,072
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEAR	10,555,018	10,694,286
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	2,617,061	3,148,010
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	19,492,563	21,105,714
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL	3,272,229	3,663,559
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	4,125,362	4,673,510
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	1,177,880	1,338,963
393	STORES EQUIPMENT	7,850	7,849
394	TOOLS, SHOP AND GARAGE EQUIPMENT	17,800,939	17,652,042
395	LABORATORY EQUIPMENT	206,728	200,930
396	POWER OPERATED EQUIPMENT	5,533,473	6,098,760
397	COMMUNICATION EQUIPMENT	1,327,818	1,216,151
398	MISCELLANEOUS EQUIPMENT	947,394	1,208,168
399	OTHER TANGIBLE PROPERTY	0	0
TOTAL GENERAL PLANT		**131,882,081**	**138,357,111**
TOTAL DEPRECIABLE GAS PLANT		**1,503,032,009**	**1,503,820,366**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	8,448,721	8,897,430
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,560,257	1,481,740
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	0	0
TOTAL COMMON PLANT		**10,008,978**	**10,379,170**
INFORMATION SERVICES (IS)			
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	9,832,470	9,593,313
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	7,979,251	7,387,482
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAR	28,916,833	28,933,224
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEAR	75,183,316	73,969,743
TOTAL INFORMATION SERVICES		**121,911,870**	**119,883,762**
TOTAL OTHER UTILITY PLANT		**131,920,848**	**130,262,932**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2027

ACCOUNT		CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
(1)		(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0
329	OTHER STRUCTURES	0	0
332	FIELD LINES	0	0
335	DRILLING AND CLEANING EQUIPMENT	0	0
TOTAL PRODUCTION PLANT		**0**	**0**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	577,128	594,389
366	STRUCTURES AND IMPROVEMENTS	138,840	157,263
367	MAINS	19,581,868	23,931,881
369	MEASURING AND REGULATING STATION EQUIPMENT	3,885,365	4,437,172
370	COMMUNICATION EQUIPMENT	2,161,300	2,630,636
371	OTHER EQUIPMENT	122,537	134,860
371.1	TESTING EQUIPMENT	171,070	176,829
TOTAL TRANSMISSION PLANT		**26,638,108**	**32,063,030**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,429,951	1,594,150
375	STRUCTURES AND IMPROVEMENTS	3,308,995	3,773,607
376.1	MAINS - PRIMARILY STEEL	220,502,463	220,451,099
376.2	MAINS - CAST IRON	664,758	664,769
376.3	MAINS - PLASTIC	423,118,421	422,700,224
376.5	MAINS - PRIMARILY WROUGHT IRON	267,248	266,181
376.7	REG AFUDC	214,839	329,843
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	47,695,551	51,379,895
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	17,446,292	18,453,572
380	SERVICES	540,528,588	508,597,998
381	METERS	64,071,604	70,109,842
381.1	METERS - ERTS	24,132,244	21,630,260
382	METER INSTALLATIONS	49,436,213	52,437,651
383	HOUSE REGULATORS	6,068,544	6,278,044
384	HOUSE REGULATOR INSTALLATIONS	8,713,720	10,128,089
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	19,107,009	22,284,010
386	OTHER PROPERTY ON CUSTOMERS PREMISES	43,272	44,596
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	641,374	659,589
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	23,780	24,705
387	OTHER EQUIPMENT	2,871,022	3,405,789
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,487,856	1,488,355
TOTAL DISTRIBUTION PLANT		**1,431,773,744**	**1,416,702,268**

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2027

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	58,437,112	61,472,930
390.3	CNG STATIONS	752,824	753,027
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	2,619,822	2,451,215
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	110,077	100,398
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	9,723,327	9,567,172
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	2,614,162	2,777,598
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	13,133,886	13,235,056
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	2,962,594	3,536,013
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	23,772,356	24,639,835
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL	3,829,924	4,261,968
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	4,970,994	5,541,637
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	1,340,181	1,518,810
393	STORES EQUIPMENT	8,641	8,640
394	TOOLS, SHOP AND GARAGE EQUIPMENT	18,585,546	18,442,253
395	LABORATORY EQUIPMENT	228,616	223,369
396	POWER OPERATED EQUIPMENT	6,294,184	6,979,558
397	COMMUNICATION EQUIPMENT	869,484	752,256
398	MISCELLANEOUS EQUIPMENT	965,109	1,222,745
399	OTHER TANGIBLE PROPERTY	0	0
TOTAL GENERAL PLANT		**151,218,839**	**157,484,480**
TOTAL DEPRECIABLE GAS PLANT		**1,609,630,691**	**1,606,249,778**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	9,781,635	10,428,247
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,807,834	1,734,257
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	0	0
TOTAL COMMON PLANT		**11,589,469**	**12,162,504**
INFORMATION SERVICES (IS)			
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	12,937,425	13,076,764
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	8,669,345	8,151,507
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	38,543,139	37,514,115
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	84,101,519	83,072,623
TOTAL INFORMATION SERVICES		**144,251,428**	**141,815,009**
TOTAL OTHER UTILITY PLANT		**155,840,897**	**153,977,513**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

I-A-6

Request:

Supply a schedule by account and depreciable group showing the survivor curve and annual accrual rate estimated to be appropriate:

a. For the purposes of this filing.

b. For the purposes of the most recent rate increase filing prior to the current proceedings.

(i) Supply a comprehensive statement of any changes made in method of depreciation and in the selection of average service lives and dispersion.

Response:

a. Refer to Table 1 in Exhibit C (Historic), Table 1 in Exhibit C (Future) and Table 1 in Exhibit C (Fully Projected) for schedules showing the estimated survivor curves and accrual rates by account and depreciable group.

b. Refer to Attachment I-A-6 for the survivor curves and annual accrual rates estimated to be appropriate in the most recent prior rate filing. UGI's most recent prior base rate case was filed in January 27, 2025 at Docket No. R-2024-3052716.

(i) The depreciation methods and procedures used in this filing are the same as those used in the previous filing.

The survivor curve estimates are based on a service life study as described in Part III of Exhibit C (Future). The service life study was updated to include company data through fiscal-year end 2022, i.e., September 30, 2022. The company's most recent 5-year service life study report was filed with the Pennsylvania Public Utility Commission on May 30, 2023. The service lives and survivor curves approved in that report were used to calculate depreciation rates as of September 30, 2025, September 30, 2026 and September 30, 2027 in the current proceeding. The charts and life tables supporting the updated service life study are presented in Part VI of Exhibit C (Future).

I-A-6 (Continued)

The Company updates its service life study every five years and submits a report to the Pennsylvania Public Utility Commission (PA PUC) in accordance with 52 Pa. Code Chapter 73.5 and 73.6. Additionally, UGI submits Annual Depreciation Reports each year in accordance with 52 Pa. Code Chapter 73.3 and 73.4.

The purpose of the regulations set forth in 52 Pa. Code Chapter 73 is to establish uniform and industry-wide reporting requirements designed to improve the Commission's ability to monitor on a regular basis the depreciation and capital planning of utilities subject to Commission jurisdiction.

Prepared by or under the supervision of: John F. Wiedmayer

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION			0	0	0	-	0
329	OTHER STRUCTURES			0	0	0	-	0
332	FIELD LINES			0	0	0	-	0
335	DRILLING AND CLEANING EQUIPMENT			0	0	0	-	0
TOTAL PRODUCTION PLANT				**0**	**0**	**0**	**-**	**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	582,842	285,318	1.25	10,855
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	156,893	5,323	0.18	288
367	MAINS		75 - R2.5	38,533,782	23,521,198	15,012,584	0.99	380,996
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2.5	6,172,846	4,343,284	1,829,562	1.41	87,130
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,505,204	2,542,911	962,293	2.32	81,475
371	OTHER EQUIPMENT		35 - R2.5	140,637	133,883	6,754	0.60	837
371.1	TESTING EQUIPMENT		20 - R3	210,011	172,302	37,709	2.10	4,416
TOTAL TRANSMISSION PLANT				**49,592,856**	**31,453,313**	**18,139,543**	**1.14**	**565,997**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,345,070	1,549,980	1,795,090	1.25	41,835
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	8,694,732	3,675,308	5,019,424	1.97	171,006
376.1	MAINS - PRIMARILY STEEL		75 - R2.5	790,186,910	219,742,145	570,444,765	1.49	11,779,098
376.2	MAINS - CAST IRON	09-2027	65 - R1	309,585	(525,943)	835,528	269.89	835,530
376.3	MAINS - PLASTIC		68 - R3	2,155,947,851	394,334,581	1,761,613,270	1.64	35,293,684
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	269,295	212,693	56,602	2.59	6,974
376.7	REG AFUDC		40 - SQ	1,322,088	300,224	1,021,864	2.50	33,052
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		48 - S0	223,494,701	47,051,873	176,442,828	2.78	6,211,615
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R1.5	64,699,936	15,314,459	49,385,477	2.71	1,751,191
380	SERVICES		45 - R2	1,838,567,224	499,831,051	1,338,736,173	2.62	48,200,375
381	METERS		36 - R2	197,734,109	68,956,720	128,777,389	3.00	5,939,393
381.1	METERS - ERTS		17 - S3	24,203,372	20,145,594	4,057,778	1.85	448,772
382	METER INSTALLATIONS		45 - R2	129,078,153	44,681,612	84,396,541	2.42	3,123,949
383	HOUSE REGULATORS		45 - R2	10,131,918	6,032,674	4,099,244	2.08	210,725
384	HOUSE REGULATOR INSTALLATIONS		45 - R2	17,644,195	9,817,668	7,826,527	1.82	321,232
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	45,235,910	20,912,140	24,323,770	2.06	932,876
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		45 - R2	68,824	15,314	53,510	5.61	3,861
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R1.5	974,397	645,658	328,739	1.85	17,981
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,720	(15)	-	0
387	OTHER EQUIPMENT		40 - R2.5	5,231,798	3,313,333	1,918,465	1.65	86,077
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,485,445	5,219	0.24	3,516
TOTAL DISTRIBUTION PLANT				**5,518,655,437**	**1,357,517,249**	**4,161,138,188**	**2.09**	**115,412,742**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS*	166,102,291	54,014,408	112,087,884	3.47	5,765,285
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,874,617	2,270,152	3,604,465	5.50	323,368
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	261,671	103,901	157,770	10.42	27,259
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	11,302,638	7,205,331	4,097,307	21.38	2,416,061

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

	ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	6,131,804	1,989,993	4,141,811	9.49	581,624
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	44,367,151	10,346,997	34,020,154	6.71	2,978,670
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,609,827	3,209,398	1,400,429	8.14	375,304
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	48,625,554	21,322,878	27,302,676	10.35	5,034,683
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL		12 - L3	4,943,306	2,143,976	2,799,330	8.79	434,715
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	9,343,381	4,401,376	4,942,005	7.89	737,296
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	3,053,256	1,219,578	1,833,678	6.83	208,576
393	STORES EQUIPMENT		20 - SQ	15,838	7,854	7,984	4.98	789
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	46,548,233	17,830,408	28,717,825	5.02	2,338,812
395	LABORATORY EQUIPMENT		20 - SQ	437,779	200,580	237,199	5.05	22,090
396	POWER OPERATED EQUIPMENT		16 - L2	12,048,672	5,988,623	6,060,049	6.18	744,520
397	COMMUNICATION EQUIPMENT		10 - SQ	1,799,482	1,027,826	771,656	8.60	154,705
398	MISCELLANEOUS EQUIPMENT		15 - SQ	2,420,119	1,558,842	861,277	3.41	82,521
399	OTHER TANGIBLE PROPERTY			0	0	0	-	0
TOTAL GENERAL PLANT				**367,885,619**	**134,842,121**	**233,043,499**	**6.04**	**22,226,278**
TOTAL DEPRECIABLE GAS PLANT				**5,936,133,912**	**1,523,812,683**	**4,412,321,230**	**2.33**	**138,205,017**
NONDEPRECIABLE PLANT								
301	ORGANIZATION			166,478				
302	FRANCHISES AND CONSENTS			193,597				
303	MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1	LAND AND LAND RIGHTS - LAND			0				
304.2	LAND AND LAND RIGHTS - LAND RIGHTS			0				
325.1	PRODUCING LANDS			0				
325.5	OTHER LAND			0				

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
365.1 LAND			47,323				
374.1 LAND AND LAND RIGHTS - LAND			849,347				
374.2 LAND AND LAND RIGHTS - LAND RIGHTS			7,394,704				
389.1 LAND AND LAND RIGHTS - LAND			7,330,889				
389.2 LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT			**16,273,518**				
TOTAL GAS PLANT			**5,952,407,430**				
OTHER UTILITY PLANT							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS							
UGI HEADQUARTERS BUILDING - DENVER	01-2069	70 - R1	34,882,907	6,601,595	28,281,312	2.55	890,928
READING DATA CENTER	09-2073	70 - R1	20,405,137	1,987,444	18,417,693	2.83	576,865
KNITTING MILLS OFFICE	06-2050	70 - R1	1,382,240	257,228	1,125,012	3.96	54,718
TOTAL ACCOUNT 390.1			*56,670,284*	*8,846,267*	*47,824,017*	*2.69*	*1,522,511*
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,500,771	1,613,585	2,887,186	4.85	218,392
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	0	(188,736)	188,736	-	0
TOTAL COMMON PLANT			**68,257,127**	**10,271,116**	**50,899,939**	**2.85**	**1,740,903**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.89%			**61,356,331**	**9,232,706**	**45,753,955**		**1,564,898**
INFORMATION SERVICES (IS)							
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	12,252,898	7,248,774	5,004,124	20.69	2,535,011
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE							
SUCCESS FACTORS	09-2024	SQUARE	0	0	0	-	0
UNITE ERP	09-2034	SQUARE	10,695,816	4,583,310	6,112,506	7.14	764,063
TOTAL ACCOUNT 391.2			*10,695,816*	*4,583,310*	*6,112,506*	*7.14*	*764,063*
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	98,317,232	28,429,099	69,888,133	10.07	9,901,794
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	122,724,937	62,365,520	60,359,417	7.80	9,572,364
TOTAL INFORMATION SERVICES			**243,990,883**	**102,626,703**	**141,364,180**	**9.33**	**22,773,232**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82447%			**206,963,973**	**87,052,557**	**119,911,416**		**19,317,273**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS			16,461,866	9,658,803	6,803,064	2.54	418,801
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**2,151,566**	**1,262,406**	**889,160**		**54,737**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**266,168,738**	**95,022,857**	**164,776,211**		**20,827,434**
TOTAL PLANT IN SERVICE			**6,218,576,168**	**1,618,835,540**	**4,577,097,441**		**159,032,451**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
AMORTIZATION OF NEGATIVE NET SALVAGE							**8,088,754**
GRAND TOTAL			**6,218,576,168**	**1,618,835,540**	**4,577,097,441**		**167,121,205**

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.

I-A-7

Request:

Provide a table, showing the cumulative depreciated original cost by year of installation for utility plant in service at the end of the test year (depreciable plant only) as claimed in the measures of value, in the following form:

a. Year installed.

b. Original cost--the total surviving cost associated with each installation year from all plant accounts.

c. Calculated depreciation reserve--the calculated depreciation reserve associated with each installation year from all plant accounts.

d. Depreciated original cost--(Column B minus Column C).

e. Total--cumulation year by year of the figures from Column D.

f. Column E divided by the total of the figure in Column D.

Response:

The information is provided in Exhibit C (Fully Projected) in Part III for the fully projected test year ended September 30, 2027; in Exhibit C (Future) in Part V for the future test year ended September 30, 2026; and in Exhibit C (Historic) in Part III for the historic test year ended September 30, 2025. The information is set forth in the section titled “Cumulative Depreciated Original Cost.”

Prepared by or under the supervision of: John F. Wiedmayer

I-A-8

Request:

Provide a description of the trending methodology which was utilized. Identify all indexes which were used (include all backup workpapers) and the reasons particular indexes were chosen. If indexes were spliced, indicate which years were utilized in any splices. If indexes were composited, show all supporting calculations. Include any analysis made to "test" the applicability of any indexes.

a. Supply a comprehensive statement of any changes made in the selection of trend factors or in the methodology used in the current rate filing compared to the most recent previous rate filing.

Response:

Trended Original Cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-9

Request:

Provide an exhibit indicating the spot trended original cost at test year end by vintage by account and include applicable depreciation reserves. Include totals by account for all other trended measures of value.

Response:

Trended Original Cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-10

Request:

Supply an exhibit indicating the percentages of undepreciated original cost which were trended with the following indexes:

a. Boeckh
b. Handy-Whitman
c. Indexes developed from suppliers' prices.
d. Indexes developed from company records and company price histories.
e. Construction equipment.
f. Government statistical releases.

Response:

Trended Original Cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-11

Request:

Provide a table, showing the cumulative trended depreciated original cost (at the spot price level) by year of installation for utility plant in service at the end of the test year (depreciable plant only) as claimed in the measures of value, in the following form:

a. Year installed.

b. Trended original cost (at the spot price level)--the total surviving cost associated with each installation year from all plant accounts.

c. Trended calculated depreciation reserve--the calculated depreciation reserve associated with each installation year from all plant accounts.

d. Depreciated trended original cost--(Column B minus Column C).

e. Total--cumulation year by year of the figures from Column D.

f. Column E divided by the total of the figures in Column D.

Response:

Trended Original Cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-12

Request:

If a claim is made for construction work in progress, include, in the form of an exhibit, the summary page from all work orders, amount expended at the end of the test year and anticipated in-service dates. Indicate if any of the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion date and estimated total amounts to be spent on each project.

[These exhibits should be updated at the conclusion of these proceedings.]

Response:

No claim is being made for construction work in progress.

Prepared by or under the supervision of: Amy M. Keller

I-A-13

Request:

If a claim is made for non-revenue producing construction work in progress, include, in the form of an exhibit, the summary page from all work orders, amount expended at the end of the test year and anticipated in-service dates. Indicate if any of the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion date and estimated total amounts to be spent on each project.

[These exhibits should be updated at the conclusion of these proceedings.]

Response:

No claim is being made for non-revenue producing construction work in progress.

Prepared by or under the supervision of: Amy M. Keller

I-A-14

Request:

If a claim is made for plant held for future use, supply the following

a. A brief description of the plant or land site and its cost.

b. Expected date of use for each item claimed.

c. Explanation as to why it is necessary to acquire each item in advance of its date of use.

d. Date when each item was acquired.

e. Date when each item was placed in plant held for future use.

Response:

No claim is being made for plant held for future use.

Prepared by or under the supervision of: Amy M. Keller

I-A-15

Request:

If materials and supplies comprise part of the cash working capital claim, attach an exhibit showing the actual book balances for materials and supplies by month for the thirteen months prior to the end of the test year. Explain any abrupt changes in monthly balances.

[Explain method of determining claim if other than that described above.]

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-8.

Prepared by or under the supervision of: Amy M. Keller

I-A-16

Request:

If fuel stocks comprise part of the cash working capital claim, provide an exhibit showing the actual book balances (quantity and price) for the fuel inventories by type of fuel for the thirteen months prior to the end of the test year by location, station, etc.

[Explain the method of determining claim if other than that described above.]

Response:

Please refer to Attachment SDR-RR-45. The fuel represents gas inventory stored underground.

Prepared by or under the supervision of: Amy M. Keller

I-A-17

Request:

Regardless of whether a claim for net negative or positive salvage is made, attach an exhibit showing gross salvage, cost of removal, and net salvage for the test year and four previous years by account.

Response:

The information related to the historic test year is presented in Part IV of Exhibit C (Historic) in the section titled “Experienced Net Salvage.” The information related to the future test year is set forth in Part VIII of Exhibit C (Future) in the section titled “Experienced and Estimated Net Salvage.” The information related to the fully projected test year is set forth in Part IV of Exhibit C (Fully Projected) in the section titled “Experienced and Estimated Net Salvage.”

Prepared by or under the supervision of: John F. Wiedmayer

I-A-18

Request:

Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not previously mentioned, in the measures of value.

Response:

All measures of value have been fully disclosed in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules A-1 and C-1 through C-8, as well as the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 4 and Amy M. Keller, UGI Gas Statement No. 5.

Prepared by or under the supervision of: Amy M. Keller

I-C-1

Request:

Provide, with respect to the scope of operations of the utility, a description of all property, including an explanation of the system's operation, and all plans for any significant future expansion, modification, or other alteration of facilities.

This description should include, but not be limited to the following:

a. If respondent has various gas service areas, indicate if they are integrated, such that the gas supply is available to all customers.

b. Provide all pertinent data regarding company policy related to the addition of new consumers in the company's service area.

c. Explain how respondent obtains its gas supply, as follows:

   (i) Explain how respondent stores or manufactures gas; if applicable.
   (ii) State whether the company has peak shaving facilities.
   (iii) Provide details of coal-gasification programs, if any.
   (iv) Describe the potential for emergency purchases of gas.
   (v) Provide the amount of gas in MCF supplied by various suppliers in the test year (include a copy of all contracts).
   (vi) Provide the amount of gas in MCF supplied from company-owned wells during the test year.

d. Provide plans for future gas supply, as follows:

   (i) Supply details of anticipated gas supply from respondent's near-term development of gas wells, if any.

   (ii) Provide gas supply agreements and well development ventures and identify the parties thereto.

e. Indicate any anticipated curtailments and explain the reasons for the curtailments.

f. Provide current data on any Federal Power Commission action or programs that may affect, or tend to affect, the natural gas supply to the gas utility.

I-C-1 (Continued)

Response:

a. The UGI Gas system consists of approximately 12,000 miles of distribution main and approximately 300 miles of transmission lines served primarily from over 85 city gate stations or interconnections with interstate pipelines. The distribution system served approximately 694,000 customers as of September 30, 2025. Ninety percent of the customers are residential.

UGI Gas distributes natural gas to territories as listed in its Tariff.

UGI Gas distribution systems are fed directly by nine interstate pipelines, Tennessee Gas Pipeline Company ("Tennessee"), Columbia Gas Transmission ("Columbia"), Transcontinental Gas Pipe Line Company, LLC. ("Transco"), Texas Eastern Transmission, LP (“Texas Eastern”), UGI Sunbury, LLC (“Sunbury”), UGI Mt. Bethel Pipeline Company, LLC (“Mt. Bethel”), Eastern Gas Transmission and Storage ("EGTS"), Adelphia Gateway ("Adelphia"), and UGI Storage Company (“UGI Storage”). Some distribution systems are fed by multiple pipelines and others are isolated feeds.

b. UGI Gas pursues the addition of new and expanded load in the residential, commercial, and industrial market areas. UGI Gas follows its tariff guidelines in obtaining these additions.

UGI Gas’ tariff guidelines define the rate schedule the customer can utilize, the investment UGI Gas makes to obtain the customer, and all other aspects of the Company’s business.

Beyond the tariff provisions, the other controlling factors in obtaining new load would be the availability from interstate pipelines, gas supply, and capacity on the UGI Gas distribution system.

All customer additions are administered through the Marketing Department. All new customer requests are in the form of a gas application. Once the application has been reviewed for distribution system adequacy, credit and cost, an approval letter is sent to the customer. If a new meter, service or main is required, the work is also scheduled at the time of approval.

I-C-1 (Continued)

c. (i) UGI Gas does not manufacture gas. UGI Gas does not own gas storage facilities.

(ii) UGI Gas does not own peak shaving facilities.

(iii) UGI Gas does not own coal gasification programs.

(iv) UGI Gas does not anticipate the purchase of emergency gas.

(v) Please see Attachment III-E-36 which provides the purchases made from various producers from October 2024 through September 2025. The producer names have been replaced with alphabetic letters for confidentiality reasons. The purchases are typically made under the provision of a standard GISB (Gas Industry Standards Board) or NAESB (North American Energy Standards Board) contract. Most contracts have special provisions adding language that may not have been contemplated when the GISB or NAESB contracts were first deployed.

(vi) Not applicable. UGI Gas does not own any gas wells.

d. (i) UGI Gas does not anticipate any development of company-owned gas wells.

(ii) UGI Gas does not have well development ventures. UGI Gas' gas supply arrangements are detailed in its annual Purchased Gas Cost filings, the most recent of which was docketed at R-2025-3054938.

e. UGI Gas does not anticipate curtailments for the system.

f. UGI Gas monitors FERC activity and evaluates pending impacts to rate payers. The FERC proceedings in which UGI Gas intervened are provided in the 1307(f) Purchased Gas Cost filings for 2025 in Book 1, Section 3 at Docket No. R-2025-3054938.

Prepared by or under the supervision of: Jill E. Walter

I-C-2

Request:

Provide an overall system map, including and labeling all measuring and regulating stations, storage facilities, production facilities, transmission and distribution mains, by size, and all interconnections with other utilities and pipelines.

Response:

In light of the security concerns reflected in the Commission's Workplace Security Survey at Docket No. M-00021590, UGI Gas has not included system maps in this filing.

Prepared by or under the supervision of: Jill E. Walter

SECTION 53.53 – RATE OF RETURN

II-A-1

Request:

Provide capitalization and capitalization ratios for the last five-year period and projected through the next two years. (With short-term debt and without short-term debt.) (Company, Parent and System (consolidated)).

a. Provide year-end interest coverages before and after taxes for the last three years and at latest date. (Indenture and SEC Bases.) (Company, Parent and System (consolidated)).

b. Provide year-end preferred stock dividend coverages for last three years and at latest date (Charter and SEC bases).

Response:

Please see Attachment II-A-1 for capitalization and capitalization ratios.

For interest coverage ratios, please see the responses to II-A-7 (for Parent, UGI Corporation) and SDR-RR-23 (for Company, UGI Utilities, Inc.).

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Capitalization Ratios for UGI Corporation and UGI Utilities, Inc.
For the Years Ended September 30, 2021 - 2027
$s in millions

Consolidated - UGI Corporation - With Short-Term Debt

	9/30/2021 Actual	%	9/30/2022 Actual	%	9/30/2023 Actual	%	9/30/2024 Actual	%	9/30/2025 Actual	%	9/30/2026 Plan	%	9/30/2027 Plan	%
Common Equity	$5,309.0	43.0	$5,904.0	45.2	$4,219.0	36.2	$4,345.0	37.8	$4,777.0	40.1				
Preferred Stock	213.0	1.7	162.0	1.2	167.0	1.4	0.0	0.0	0.0	0.0				
Minority Interests	9.0	0.1	8.0	0.1	8.0	0.1	9.0	0.1	9.0	0.1				
Short-Term Debt	367.0	3.0	368.0	2.8	649.0	5.6	465.0	4.0	486.0	4.1				
Long-Term Debt	6,449.0	52.2	6,632.0	50.7	6,600.0	56.7	6,678.0	58.1	6,648.0	55.8				
Total Capitalization	$12,347.0	100.0	$13,074.0	100.0	$11,643.0	100.0	$11,497.0	100.0	$11,920.0	100.0	$0.0	0.0	$0.0	0.0

Consolidated - UGI Corporation - Without Short-Term Debt

	9/30/2021 Actual	%	9/30/2022 Actual	%	9/30/2023 Actual	%	9/30/2024 Actual	%	9/30/2025 Actual	%	9/30/2026 Plan	%	9/30/2027 Plan	%
Common Equity	$5,309.0	44.3	$5,904.0	46.5	$4,219.0	38.4	$4,345.0	39.4	$4,777.0	41.8				
Preferred Stock	213.0	1.8	162.0	1.3	167.0	1.5	0.0	0.0	0.0	0.0				
Minority Interests	9.0	0.1	8.0	0.1	8.0	0.1	9.0	0.1	9.0	0.1				
Long-Term Debt	6,449.0	53.8	6,632.0	52.2	6,600.0	60.0	6,678.0	60.5	6,648.0	58.1				
Total Capitalization	$11,980.0	100.0	$12,706.0	100.1	$10,994.0	100.0	$11,032.0	100.0	$11,434.0	100.0	$0.0	0.0	$0.0	0.0

Company Only - UGI Utilities, Inc. - With Short-Term Debt

	9/30/2021 Actual	%	9/30/2022 Actual	%	9/30/2023 Actual	%	9/30/2024 Actual	%	9/30/2025 Actual	%	9/30/2026 Plan	%	9/30/2027 Plan	%
Common Equity	$ 1,424.9	50.7	$ 1,654.8	52.1	$ 1,861.3	55.0	$ 1,945.2	53.3	$ 2,094.6	52.9	$ 2,305.9	54.1	$ 2,524.7	54.3
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	-	0.0	0.0	0.0	0.0
Short-Term Debt	93.2	3.3	63.0	2.0	67.1	2.0	8.0	0.2	0.0	-	23.7	0.6	0.0	0.0
Long-Term Debt	1,291.6	46.0	1,460.3	45.9	1,454.1	43.0	1,697.8	46.5	1,866.6	47.1	1,935.3	45.3	2,129.1	45.7
Total Capitalization	$ 2,809.7	100.0	$ 3,178.1	100.0	$ 3,382.5	100.0	$ 3,651.0	100.0	$ 3,961.2	100.0	$ 4,264.8	100.0	$ 4,653.8	100.0

Company Only - UGI Utilities, Inc. - Without Short-Term Debt

	9/30/2021 Actual	%	9/30/2022 Actual	%	9/30/2023 Actual	%	9/30/2024 Actual	%	9/30/2025 Actual	%	9/30/2026 Plan	%	9/30/2027 Plan	%
Common Equity	$ 1,424.9	52.5	$ 1,654.8	53.1	$ 1,861.3	56.1	$ 1,945.2	53.4	$ 2,094.6	52.9	$ 2,305.9	54.4	$ 2,524.7	54.3
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long-Term Debt	1,291.6	47.5	1,460.3	46.9	1,454.1	43.9	1,697.8	46.6	1,866.6	47.1	1,935.3	45.6	2,129.1	45.7
Total Capitalization	$ 2,716.5	100.0	$ 3,115.1	100.0	$ 3,315.4	100.0	$ 3,643.0	100.0	$ 3,961.2	100.0	$ 4,241.2	100.0	$ 4,653.8	100.0

II-A-2

Request:

Provide latest quarterly financial report (Company and Parent).

Response:

A copy of the Company's latest quarterly financial report as of September 30, 2025 can be found at https://www.ugicorp.com/static-files/97e640c1-4d75-45f5-b1a9-65cbee300d94.

Please refer to II-A-3 for the latest quarterly financial report of UGI Corporation as of September 30, 2025.

Prepared by or under the supervision of: Amy M. Keller

II-A-3

Request:

Provide latest Stockholder's Report (Company and Parent).

Response:

UGI Utilities, Inc. does not produce an annual Stockholder's Report.

Please refer to the SEC website for a copy of UGI Corporation's latest Stockholder's Report on form 10-K. This can be found at https://www.ugicorp.com/sec-filings/sec-filing/10-k/0000884614-25-000053.

Prepared by or under the supervision of: Amy M. Keller

II-A-4

Request:

Provide latest Prospectus (Company and Parent).

Response:

Please see the following link for the Prospectus Supplement from UGI Utilities Senior Notes Offering dated 9/24/08 for the latest UGI Utilities Prospectus: https://www.sec.gov/Archives/edgar/data/100548/000119312508201953/d424b2.htm .

Please see the following link for the latest UGI Corporation prospectus dated 5/23/24: https://www.sec.gov/Archives/edgar/data/0000884614/000110465924064780/tm2415104-1_s3asr.htm.

Prepared by or under the supervision of: Amy M. Keller

II-A-5

Request:

Supply projected capital requirements and sources of Company, Parent and System (consolidated) for each of future three years.

Response:

See Attachment II-A-5 for projected capital expenditure requirements for Fiscal Years ending September 30, 2026 and September 30, 2027. The sources of funds may be internally generated contributions from the parent or from outside financing, as needed.

The projection for Fiscal Year 2028 is confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Vicky A. Schappell

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED CAPITAL EXPENDITURES
FOR THE YEARS ENDED SEPTEMBER 30, 2026 AND 2027
(millions of dollars)

		2026		2027
Consolidated UGI Utilities, Inc. (including Electric Division)	$	530.0	$	608.0
UGI Utilities, Inc. - Gas Division	$	471.9	$	562.6

II-A-6

Request:

Provide a schedule of debt and preferred stock of Company, Parent and System (consolidated) as of test year-end and latest date, detailing for each issue (if applicable):

a. Date of issue
b. Date of maturity
c. Amount issued
d. Amount outstanding
e. Amount retired
f. Amount reacquired
g. Gain on reacquisition
h. Coupon rate
i. Discount or premium at issuance
j. Issuance expenses
k. Net proceeds
l. Sinking Fund requirements
m. Effective interest rate
n. Dividend rate
o. Effective cost rate
p. Total average weighted effective Cost Rate

Response:

Please refer to Attachment II-A-6.

Prepared by or under the supervision of: Dylan D'Ascendis

UGI Utilities, Inc.
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Date of Issue	Date of Maturity	Pay Off Date	Average Term in Years	Principal Amount Issued ($000)	Premium/Discount & Issuance Costs ($000)	Net Proceeds ($000)	Net Proceeds Ratio	Effective Cost Rate (1)
Medium Term Notes									
6.500%	08/14/03	08/15/33		30	20,000	150	19,850	99.25%	6.56%
6.133%	10/14/04	10/15/34		30	20,000	150	19,850	99.25%	6.19%
Senior Notes									
6.206%	09/15/06	09/30/36		30	100,000	1,485	98,515	98.52%	6.32%
4.980%	03/26/14	03/26/44		30	175,000	642	174,358	99.63%	5.00%
2.950%	06/30/16	06/30/26	06/30/26	10	100,000	7,949	92,051	92.05%	3.92%
4.120%	09/30/16	09/30/46		30	200,000	27,366	172,634	86.32%	5.01%
4.120%	10/31/16	10/31/46		30	100,000	2,710	97,290	97.29%	4.28%
4.550%	02/01/19	02/01/49		30	150,000	713	149,288	99.53%	4.58%
3.120%	03/19/20	04/16/50		30	150,000	835	149,165	99.44%	3.15%
1.590%	06/15/21	06/15/26	11/17/25	5	100,000	680	99,320	99.32%	1.73%
1.640%	09/15/21	09/15/26	11/17/25	5	75,000	390	74,611	99.48%	1.75%
4.750%	07/15/22	07/15/32		10	90,000	483	89,517	99.46%	4.82%
4.990%	09/15/22	09/15/52		30	85,000	467	84,533	99.45%	5.03%
6.100%	11/30/23	11/30/33		10	150,000	809	149,191	99.46%	6.17%
6.400%	11/30/23	11/30/53		30	75,000	292	74,708	99.61%	6.43%
6.020%	11/30/23	11/30/30		7	25,000	129	24,871	99.48%	6.11%
5.240%	11/14/24	11/30/29		5	50,000	299	49,701	99.40%	5.38%
5.520%	11/14/24	11/30/34		10	125,000	749	124,251	99.40%	5.60%
5.100%	11/14/25	11/14/35		5	150,000	750	149,250	99.50%	5.16%
5.680%	11/14/25	11/14/35		10	125,000	625	124,375	99.50%	5.75%
5.600%	06/30/26	06/30/36		10	75,000	375	74,625	99.50%	5.67%
5.693%	11/30/26	11/30/36		10	200,000	1,300	198,700	99.35%	5.78%
Term Loan									
3.917%	10/31/17	07/12/27	10/31/26	10	125,000	466	124,534	99.63%	3.96%
3.098%	10/31/26	10/31/36		10	68,751	447	68,304	99.35%	3.17%

Notes: (1) The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

Source of Information: Company Provided Data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Actual at September 30, 2025 ($ amounts in '000s)

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	20,000	1.07%	6.56%	0.07%
6.133%	10/15/34	20,000	1.07%	6.19%	0.07%
Senior Notes					
6.206%	09/30/36	100,000	5.36%	6.32%	0.34%
4.980%	03/26/44	175,000	9.38%	5.00%	0.47%
2.950%	06/30/26	100,000	5.36%	3.92%	0.21%
4.120%	09/30/46	200,000	10.72%	5.01%	0.54%
4.120%	10/31/46	100,000	5.36%	4.28%	0.23%
4.550%	02/01/49	150,000	8.04%	4.58%	0.37%
3.120%	04/16/50	150,000	8.04%	3.15%	0.25%
1.590%	06/15/26	100,000	5.36%	1.73%	0.09%
1.640%	09/15/26	75,000	4.02%	1.75%	0.07%
4.750%	07/15/32	90,000	4.82%	4.82%	0.23%
4.990%	09/15/52	85,000	4.55%	5.03%	0.23%
6.100%	11/30/33	150,000	8.04%	6.17%	0.50%
6.400%	11/30/53	75,000	4.02%	6.43%	0.26%
6.020%	11/30/30	25,000	1.34%	6.11%	0.08%
5.240%	11/30/29	50,000	2.68%	5.38%	0.14%
5.520%	11/30/34	125,000	6.70%	5.60%	0.38%
Term Loan					
3.917%	07/12/27	76,563	4.10%	3.96%	0.16%
Total Long-Term Debt		1,866,563	100.00%		4.69%

Source of Information: Company Provided Data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Projected at September 30, 2026 ($ amounts in '000s)

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	20,000	1.03%	6.56%	0.07%
6.133%	10/15/34	20,000	1.03%	6.19%	0.06%
Senior Notes					
6.206%	09/30/36	100,000	5.17%	6.32%	0.33%
4.980%	03/26/44	175,000	9.04%	5.00%	0.45%
4.120%	09/30/46	200,000	10.33%	5.01%	0.52%
4.120%	10/31/46	100,000	5.17%	4.28%	0.22%
4.550%	02/01/49	150,000	7.75%	4.58%	0.35%
3.120%	04/16/50	150,000	7.75%	3.15%	0.24%
4.750%	07/15/32	90,000	4.65%	4.82%	0.22%
4.990%	09/15/52	85,000	4.39%	5.03%	0.22%
6.100%	11/30/33	150,000	7.75%	6.17%	0.48%
6.400%	11/30/53	75,000	3.88%	6.43%	0.25%
6.020%	11/30/30	25,000	1.29%	6.11%	0.08%
5.240%	11/30/29	50,000	2.58%	5.38%	0.14%
5.520%	11/30/34	125,000	6.46%	5.60%	0.36%
5.100%	11/14/35	150,000	7.75%	5.16%	0.40%
5.680%	11/14/35	125,000	6.46%	5.75%	0.37%
5.600%	06/30/36	75,000	3.88%	5.67%	0.22%
Term Loan					
3.917%	07/12/27	70,313	3.63%	3.96%	0.14%
Total Long-Term Debt		1,935,313	100.00%		5.12%

Source of Information: Company Provided Data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Projected at September 30, 2027 ($ amounts in '000s)

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	20,000	0.94%	6.56%	0.06%
6.133%	10/15/34	20,000	0.94%	6.19%	0.06%
Senior Notes					
6.206%	09/30/36	100,000	4.70%	6.32%	0.30%
4.980%	03/26/44	175,000	8.22%	5.00%	0.41%
4.120%	09/30/46	200,000	9.39%	5.01%	0.47%
4.120%	10/31/46	100,000	4.70%	4.28%	0.20%
4.550%	02/01/49	150,000	7.05%	4.58%	0.32%
3.120%	04/16/50	150,000	7.05%	3.15%	0.22%
4.750%	07/15/32	90,000	4.23%	4.82%	0.20%
4.990%	09/15/52	85,000	3.99%	5.03%	0.20%
6.100%	11/30/33	150,000	7.05%	6.17%	0.43%
6.400%	11/30/53	75,000	3.52%	6.43%	0.23%
6.020%	11/30/30	25,000	1.17%	6.11%	0.07%
5.240%	11/30/29	50,000	2.35%	5.38%	0.13%
5.520%	11/30/34	125,000	5.87%	5.60%	0.33%
5.100%	11/14/35	150,000	7.05%	5.16%	0.36%
5.680%	11/14/35	125,000	5.87%	5.75%	0.34%
5.600%	06/30/36	75,000	3.52%	5.67%	0.20%
5.693%	11/30/36	200,000	9.39%	5.78%	0.54%
Term Loan					
3.098%	10/31/36	64,063	3.01%	3.17%	0.10%
Total Long-Term Debt		2,129,063	100.00%		5.17%

Source of Information: Company Provided Data

II-A-7

Request:

Supply financial data of Company and/or Parent for last five years:

a. Earnings-price ratio (average)
b. Earnings-book value ratio (per share basis) (avg. book value)
c. Dividend yield (average)
d. Earnings per share (dollars)
e. Dividends per share (dollars)
f. Average book value per share yearly
g. Average yearly market price per share (monthly high-low basis)
h. Pre-tax funded debt interest coverage
i. Post-tax funded debt interest coverage
j. Market price-book value ratio

Response:

Please refer to Attachment II-A-7 for the requested financial data of UGI Corporation. UGI Utilities, Inc. has no publicly traded shares outstanding.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Corporation
Select Financial Data
For the Year Ended September 30,

	2021	2022	2023	2024	2025
Income Statement Data *(millions)* :					
Revenues	$ 7,447	$ 10,106	$ 8,928	$ 7,210	$ 7,287
Reportable Segment EBIT[(1)]	$ 1,134	$ 1,166	$ 1,158	$ 1,178	$ 1,176
Adjusted Net Income attributable to UGI Corporation[(2)]	$ 629	$ 626	$ 613	$ 658	$ 728
Common Stock data:					
Market price at year end	$ 42.62	$ 32.33	$ 23.00	$ 25.02	$ 33.26
Average yearly market price per share	$ 41.09	$ 40.71	$ 32.31	$ 23.60	$ 31.71
Book value per share (at year end)	$ 26.31	$ 28.81	$ 20.80	$ 20.10	$ 22.01
Adjusted diluted earnings per share[(2)]	$ 2.96	$ 2.90	$ 2.84	$ 3.06	$ 3.32
Dividends declared per share	$ 1.35	$ 1.41	$ 1.47	$ 1.50	$ 1.50
Dividend rate per share (at year end)	$ 1.34	$ 1.41	$ 1.46	$ 1.47	$ 1.48
Ratios:					
Earnings-price ratio	14.4	11.1	8.1	8.2	10.0
Earnings-book value ratio	8.9	9.9	7.3	6.6	6.6
Dividend yield - average	3.3%	3.5%	4.5%	6.4%	4.7%
Pre-tax funded debt interest coverage	3.7	3.5	3.1	3.0	2.9
Post-tax funded debt interest coverage	3.0	3.0	2.7	2.6	2.8
Market price / Book value ratio	1.6	1.1	1.1	1.2	1.5

[(1)] Reportable segments' EBIT represents an aggregate of reportable operating segment level Earnings Before Interest and Taxes ("EBIT") as determined in accordance with U.S. generally accepted accounting principles ("GAAP").

[(2)] Management uses “adjusted net income attributable to UGI Corporation” and "adjusted diluted earnings per share," both of which are non-GAAP financial measures, when evaluating UGI's overall performance. Management believes that these non-GAAP measures provide meaningful information to investors about UGI’s performance because they eliminate the impacts of (1) gains and losses on commodity and certain foreign currency derivative instruments not associated with current-period transactions and (2) other significant discrete items that can affect the comparison of period-over-period results. Volatility in net income attributable to UGI can occur as a result of gains and losses on commodity and certain foreign currency derivative instruments not associated with current-period transactions but included in earnings in accordance with GAAP.

II-A-8

Request:

State amount of debt interest utilized for income tax calculations, and details of debt interest computations, under each of the following rate case bases:

a. Actual test year

b. Annualized test year-end

c. Proposed test year-end

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33. All external debt is held at the UGI Utilities, Inc. level. For ratemaking purposes, interest expense is synchronized to the Measure of Value funded at the claimed capital structure and cost of debt.

Prepared by or under the supervision of: Darin T. Espigh

II-A-9

Request:

State amount of debt interest utilized for income tax calculations which has been allocated from the debt interest of an affiliate, and details of the allocation, under each of the following rate case bases:

a. Actual test year

b. Annualized test year-end

c. Proposed test year-end

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33. All external debt is held at the UGI Utilities, Inc. level. For ratemaking purposes, interest expense is synchronized to the Measure of Value funded at the claimed capital structure and cost of debt.

Prepared by or under the supervision of: Darin T. Espigh

II-A-10

Request:

Under Section 1552 of the Internal Revenue Code and Regulations 1.1552-1 thereunder, if applicable, Parent Company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating members to determine each member's tax liability to the federal government. (If this interrogatory is not applicable, so state.)

a. State what option has been chosen by the group.

b. Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return.

c. Provide a schedule, in summary form, of contributions, which were determined on the basis of separate tax return calculations, made by each of the participating members to the tax liability indicated in the consolidated group tax return. Provide total amounts of actual payments to the tax depository for the tax year, as computed on the basis of separate returns of members.

d. Provide annual income tax return for group, and if income tax return shows net operating loss, provide details of amount of net operating loss allocated to the income tax returns of each of the members of the consolidated group.

Response:

a. UGI Corporation has elected to allocate the tax liability of the consolidated group to the members in accordance with Regulation 1.1502-33(d)(2)(ii). Further, the group elects to use 100 percent as the percentage specified in Regulation 1.1502-33(d)(2)(ii)(b). This method of allocation is to be applied in conjunction with the basic allocation method provided in Regulation 1.1552-1(a)(2). UGI Corporation also elected to reflect currently the investment adjustment in earnings and profits pursuant to Regulation 1.1502-33(c)(4)(iii).

b. & c. See Attachment II-A-10.

d. See SDR-RR-55 for copies of certain pages of the 9/30/24 UGI Consolidated Federal Income Tax Return.

II-A-10 (Continued)

The tax results for the year ended 9/30/24 do not show a net operating loss. See Attachment II-A-10 for further details.

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Gas Division
Allocation of UGI Corporation Consolidated Federal Income Tax Liability
For the Year Ended September 30, 2024
(thousands of dollars)

Name of Company	(a) Federal Taxable Income	(b) Federal Income Tax @ 21.00% Allocated	(c) Foreign Tax Credit	(d) General Business Credit	(e) Col (b) + Col (c) - Col (d) = Net Federal Income Tax Liability
AmeriGas Inc	0	0			0
AmeriGas Propane Inc.	(10,618)	(2,230)		(27)	(2,257)
AmeriGas Propane Holdings, Inc.	(206,473)	(43,359)			(43,359)
Amerigas Technology Group Inc.	0	0			0
Ashtola Production Company	(1)	(0)			(0)
Eastfield International Holdings Inc	0	0			0
Energy Service Funding	7,729	1,623			1,623
EuroGas Holdings Inc.	0	0			0
Four Flags Drilling Company	0	0			0
Homestead Holding	(4,612)	(969)			(969)
Mountaineer Energy Holding & Subs	25,671	5,391		(2)	5,389
Mountaintop Energy Holding LLC	(29)	(6)			(6)
Newberry Holding	(3)	(1)			(1)
UGI Asset Management	0	0			0
UGI Black Sea Enterprises	0	0			0
UGI China, Inc.	0	0			0
UGI Corporation	(41,018)	(8,614)		(22)	(8,636)
UGI Development Company	26,970	5,664			5,664
UGI Energy Ventures, Inc.	0	0			0
UGI Ethanol Development Company	0	0			0
UGI Europe, Inc.	106,229	22,308	(11,380)		10,928
UGI Hunlock Dev	0	0			0
UGI HVAC Enterprises	0	0			0
UGI International China. Inc	0	0			0
UGI International (Romania)	0	0			0
UGI LNG	4,530	951			951
UGI Penn HVAC Services	0	0			0
UGI Penn Natural Gas	0	0			0
UGI Petroleum Products of DE	0	0			0
UGI Properties, Inc.	(215)	(45)			(45)
UGI Romania, Inc.	0	0			0
UGI Storage Company	15,619	3,280			3,280
UGI Utilities, Inc.	131,241	27,561		(109)	27,452
UGID Holding Company	0	0			0
United Valley Insurance	148	31			31
Total Taxable	**55,168**	**11,585**	**(11,380)**	**(160)**	**45**

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - II-A - Rate of Return - All Utilities
Delivered on January 28, 2026

II-A-11

Request:

Provide AFUDC charged by company at test year-end and latest date, and explain method by which rate was calculated.

Response:

AFUDC totaling $3,252,575 was recorded during the historic test year. UGI Gas follows the FERC guidance for calculation of the AFUDC rate. The calculated rate for the historic test year of 4.98% was based on average construction work in process compared to short-term borrowings, long-term borrowings, and equity monthly and on an aggregated annual basis. UGI Gas is currently using the short-term debt rate for AFUDC because the average short-term borrowing balances exceeds the average construction work in process balance.

The projected short-term debt rates for the future test year (Fiscal Year 2026) and fully projected test year (Fiscal Year 2027) are 4.21% and 4.13%, respectively.

Prepared by or under the supervision of: Amy M. Keller

II-A-12

Request:

Set forth provisions of Company's and Parent's charter and indentures (if applicable) which describe coverage requirements, limits on proportions of types of capital outstanding, and restrictions on dividend payouts.

Response:

UGI Utilities, Inc. entered into an unsecured revolving credit agreement in November 2023 ("Revolving Credit Agreement") with a group of banks that provides for a loan commitment of up to $375 million. UGI Utilities, Inc. may request a $125 million increase in the amount of loan commitments under the Revolving Credit Agreement to a maximum aggregate of $500 million. Under the Revolving Credit Agreement, UGI Utilities, Inc. may borrow at various prevailing interest rates, including SOFR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based on the credit ratings of certain indebtedness of UGI Utilities, Inc.

UGI Utilities, Inc. has various issuances of Senior Notes and Medium-Term Notes due at various times from June 2026 through November 2053. The Senior Notes and Medium-Term Notes are unsecured.

UGI Utilities, Inc. has a variable rate Term Loan with a balance of $76,562,500 as of September 30, 2025, with principal payments of $1,562,500 due quarterly and the remaining principal due July 2027. Under this Term Loan, UGI Utilities, Inc. may borrow at various prevailing market interest rates, plus an applicable margin.

The Revolving Credit Agreement, certain of the Senior Notes, and the Term Loan require UGI Utilities, Inc. not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.00. Additionally, certain of the Senior Notes require that Consolidated Priority Debt not exceed 10% of Consolidated Total Assets.

Please refer to UGI Gas Exhibit B for a description of all other Notes, which do not have defined coverage requirements (other than that expressed above) limits on types of capital outstanding, or restrictions on dividend payouts.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-13

Request:

Attach copies of the summaries of the projected 2 year's Company's budgets (revenue, expense and capital).

Response:

Please see Attachment II-A-13 for the Company's 2026 and 2027 operating budget and plan. For capital budgets, please refer to the response to II-A-5.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Projected Company Budget
Twelve Months Ending September 30,
(Thousands of Dollars)

	2026	2027
Operating Revenues:		
Operating Revenues	$ 1,256,178	$ 1,270,313
Other Operating Revenues	13,334	13,419
Total Operating Revenues	1,269,512	1,283,732
Operating Expenses:		
Gas Production	-	-
Gas Supply Production	425,103	429,721
Distribution	89,214	93,549
Customer Accounts	59,816	62,160
Uncollectible Expense	20,409	20,671
Customer Service and Information	14,764	14,993
Sales	1,250	1,283
Administrative and General	106,456	112,060
Depreciation and Amortization	153,978	164,574
Taxes, Other than Income Taxes	13,359	14,299
Total Operating Expenses	884,349	913,311
Operating Income	$ 385,163	$ 370,420

II-A-14

Request:

Describe long-term debt reacquisitions by Company and Parent as follows:

a. Reacquisitions by issue by year.

b. Total gain on reacquisitions by issue by year.

c. Accounting of gain for income tax and book purposes.

Response:

Please see the response to SDR-ROR-18.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-15

Request:

Set forth amount of compensating bank balances required under each of the following rate base bases:

a. Annualized test year operations.

b. Operations under proposed rates.

Response:

Not applicable. UGI Utilities, Inc. has no compensating bank balance requirements.

Prepared by or under the supervision of: Amy M. Keller

II-A-16

Request:

Provide the following information concerning compensating bank balance requirements for actual test year:

a. Name of each bank.
b. Address of each bank.
c. Types of accounts with each bank (checking, savings, escrow, other services, etc.).
d. Average Daily Balance in each account.
e. Amount and percentage requirements for compensating bank balance at each bank.
f. Average daily compensating bank balance at each bank.
g. Documents from each bank explaining compensating bank balance requirements.
h. Interest earned on each type of account.

Response:

Not applicable. UGI Utilities, Inc. has no compensating bank balance requirements.

Prepared by or under the supervision of: Amy M. Keller

II-A-17

Request:

Provide the following information concerning bank notes payable for actual test year:

a. Line of Credit at each bank.
b. Average daily balances of notes payable to each bank, by name of bank.
c. Interest rate charged on each bank note (Prime rate, formula rate or other).
d. Purpose of each bank note (e.g., construction, fuel storage, working capital, debt retirement).
e. Prospective future need for this type of financing.

Response:

a. In November 2023, the Company entered into a five-year $375 million revolving credit facility with a consortium of banks ("2023 RCF"). The 2023 RCF is currently scheduled to expire in November 2028. Please see Attachment II-A-17 for the commitment from each bank.

b. The 2023 RCF is predominantly used to fund construction in progress and meet working capital needs and is more heavily utilized in the Fall and Winter months when inventory and receivables balances peak. The borrowings from each bank are pro rata as per their respective commitments. The average borrowing under the Company's 2023 RCF was $84.4 million for the fiscal year 2025.

c. The interest rates for the majority of borrowings under the Company's 2023 RCF are under SOFR + Applicable Margin formula. The Applicable Margin is based on public credit ratings as specified on Attachment II-A-17. The Company has two public debt ratings (Moody's and Fitch). When there is a split rating, the Moody's rating applies unless such ratings differ by two or more levels. If ratings differ by two or more levels, the applicable level will be deemed to be one level below the higher of such levels. Based on ratings at September 30, 2025, the Company's applicable margin is 0.875%.

d. The borrowings under the 2023 RCF are for working capital needs, CWIP, and general corporate purposes.

II-A-17 (Continued)

e. The 2023 RCF provides adequate liquidity for working capital needs, CWIP, and general corporate purposes and does not mature until November 2028.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Line of Credit Bank Commitments and Applicable Margin
As of September 30, 2025

Lender Commitments of the UGI Gas five year, $375 million revolving credit facility:

Lender	Commitment
PNC Bank, National Association	$65,000,000
Citizens Bank, N.A.	$65,000,000
Bank of America, N.A.	$35,000,000
The Bank of New York Mellon	$35,000,000
JPMorgan Chase Bank, N.A.	$35,000,000
Wells Fargo Bank, National Association	$35,000,000
First National Bank of PA	$35,000,000
The Huntington National Bank	$35,000,000
M&T Bank	$35,000,000
	$375,000,000

Applicable Margin of the UGI Gas five year, $375 million revolving credit facility:

Debt Rating	Margin
A/A2/A	0.875%
A-/A3/A-	1.00%
BBB+/Baa1/BBB+	1.125%
BBB/Baa2/BBB	1.25%
BBB-/Baa3/BBB-	1.50%
BB+/Ba1/BB+	1.75%

II-A-18

Request:

Set forth amount of total cash (all cash accounts) on hand from balance sheets for last 24-calendar months preceding test year-end.

Response:

The average balance sheet cash (measured at the end of each month) for the past 24 calendar months (10/31/23 - 9/30/25) was $17.8 million.

Please see Attachment II-A-18.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
MONTH-END CASH BALANCES

Fiscal Year 2024		Balance Sheet Cash
October	$	13,725,640
November	$	31,464,196
December	$	31,566,830
January	$	21,268,526
February	$	28,595,227
March	$	21,043,213
April	$	15,209,898
May	$	9,296,369
June	$	8,956,551
July	$	13,383,177
August	$	12,526,319
September	$	9,893,490

Fiscal Year 2025		Balance Sheet Cash
October	$	12,962,147
November	$	14,871,873
December	$	11,065,822
January	$	12,437,481
February	$	45,416,656
March	$	13,088,777
April	$	27,673,172
May	$	20,750,755
June	$	8,334,667
July	$	11,601,701
August	$	17,634,314
September	$	14,800,357

Two-Year Average	**$**	**17,815,298**

II-A-19

Request:

Submit details on Company or Parent common stock offerings (past 5 years to present) as follows:

a. Date of Prospectus
b. Date of offering
c. Record date
d. Offering period--dates and number of days
e. Amount and number of shares of offering
f. Offering ratio (if rights offering)
g. Per cent subscribed
h. Offering price
i. Gross proceeds per share
j. Expenses per share
k. Net proceeds per share (i-j)
l. Market price per share
    1. At record date
    2. At offering date
    3. One month after close of offering
m. Average market price during offering
    1. Price per share
    2. Rights per share--average value of rights
n. Latest reported earnings per share at time of offering
o. Latest reported dividends at time of offering

Response:

The Company has not issued stock in the last five years.

The Parent has issued stock related to the below transaction in the last five years.

On May 25, 2021, the Company's parent issued 2.2 million "Equity Units" with a total notional value of $220 million. The Equity Units were equity-linked securities and not Common Stock. Each Equity Unit was a mandatory convertible, hybrid security that combined a "Forward Contract" and a 10% undivided interest in one share "Convertible Preferred Stock" of the Parent. The Equity Units included a requirement to remarket the Convertible Preferred Stock approximately three years after issuance (May 2024).

II-A-19 (Continued)

Pursuant to the terms of the Equity Units, in May 2024, the Parent announced the unsuccessful final remarketing of its Convertible Preferred Stock. As a result, each holder of an Equity Unit received 2.2973 shares of Parent Common Stock, without par value, with cash paid in lieu of any fractional shares.

In the event of a successful remarketing of the Convertible Preferred Stock, the Parent would still have provided such Common Stock to Equity Unit holders due to the terms of the Forward Contract.

During the third quarter of Fiscal 2024, the Parent (i) made the final payment to settle the Forward Contract in full; (ii) canceled the Convertible Preferred Stock; and (iii) in a non-cash transaction, converted the Equity Units into 5,054,030 shares of Parent Common Stock and issued the shares to the holders of the Equity Units under the Forward Contract.

As noted above, the Equity Units are not common stock, although they contain terms that eventually convert a portion into Parent Common Stock.

All terms and requirements under the Equity Units are satisfied. The Equity Units are fully settled as of June 2024.

Due to the hybrid nature of these securities, the detailed requests related to Common Stock offerings do not apply.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-20

Request:

Provide latest available balance sheet and income statement for Company, Parent and System (consolidated).

Response:

Please refer to UGI Gas Exhibit A (Historic), Schedules B-1 and B-2 for balance sheet and income statement of UGI Utilities, Inc. - Gas Division.

Please see the UGI Utilities, Inc. balance sheet and income statement for the year ended 9/30/25 at https://www.ugicorp.com/static-files/97e640c1-4d75-45f5-b1a9-65cbee300d94.

Also, please see UGI Corporation Report on Form 10-K for the year ended 9/30/25 at https://www.ugicorp.com/sec-filings/sec-filing/10-k/0000884614-25-000053 for Parent Company financial statements.

Prepared by or under the supervision of: Amy M. Keller

II-A-21

Request:

Provide Original Cost, Trended Original Cost and Fair Value rate base claims.

Response:

The Company's claim is based on original cost measure of value. As Pennsylvania law requires use of original cost measure of value for ratemaking, trended original cost and fair value rate base claims were not prepared.

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-1.

Prepared by or under the supervision of: Amy M. Keller

II-A-22

Request:

a. Provide Operating Income claims under:

(i) Present rates
(ii) Pro forma present rates (annualized & normalized)
(iii) Proposed rates (annualized & normalized)

b. Provide Rate of Return on Original Cost and Fair Value claims under:

(i) Present rates
(ii) Pro forma present rates
(iii) Proposed rates

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules A-1, D-1 and D-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

II-A-23

Request:

List details and sources of “Other Property and Investment,” “Temporary Cash Investments” and “Working Funds” on test year-end balance sheet.

Response:

Please refer to the following responses:

Other Property and Investment - III-A-2

Temporary Cash Investments - III-A-3

Working Funds other than general operating cash - III-A-3

Prepared by or under the supervision of: Amy M. Keller

II-A-24

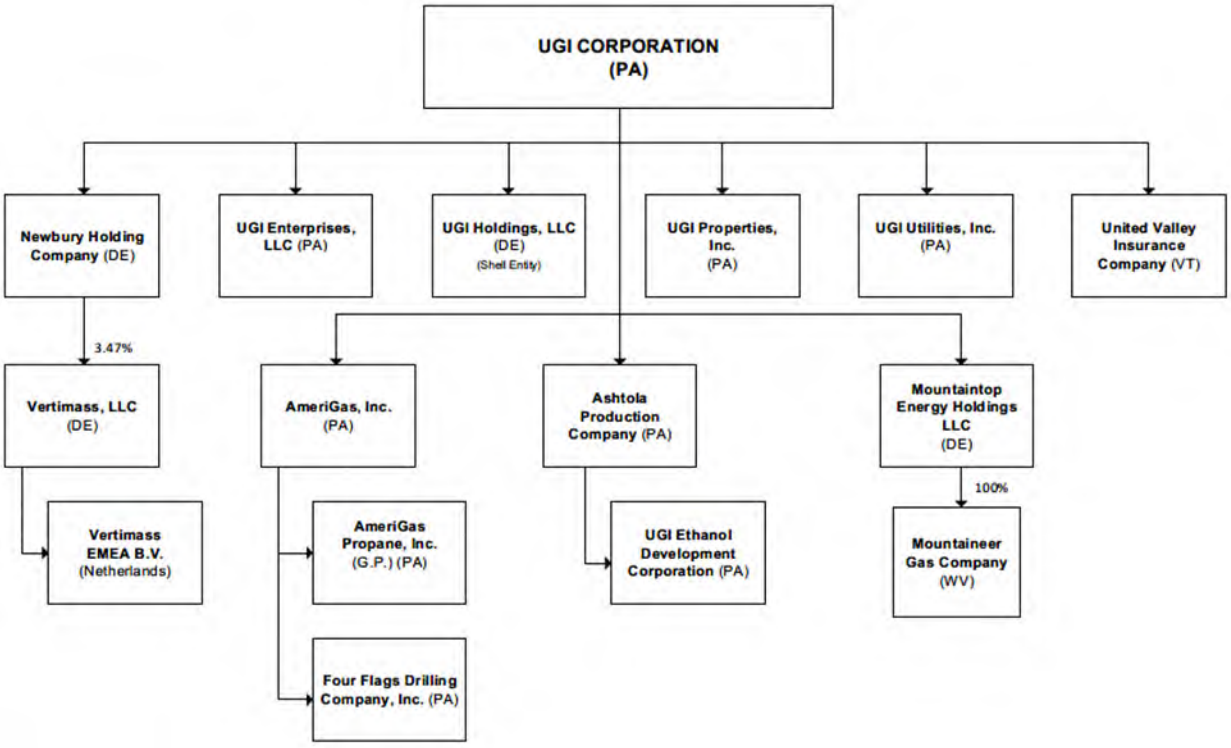
Request:

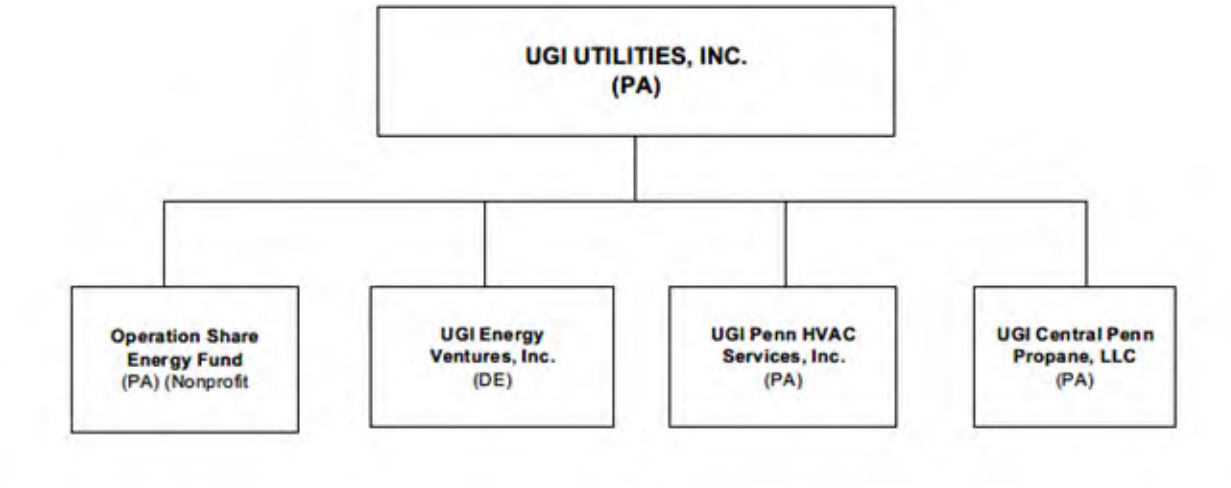
Attach chart explaining Company's corporate relationship to its affiliates (System Structure).

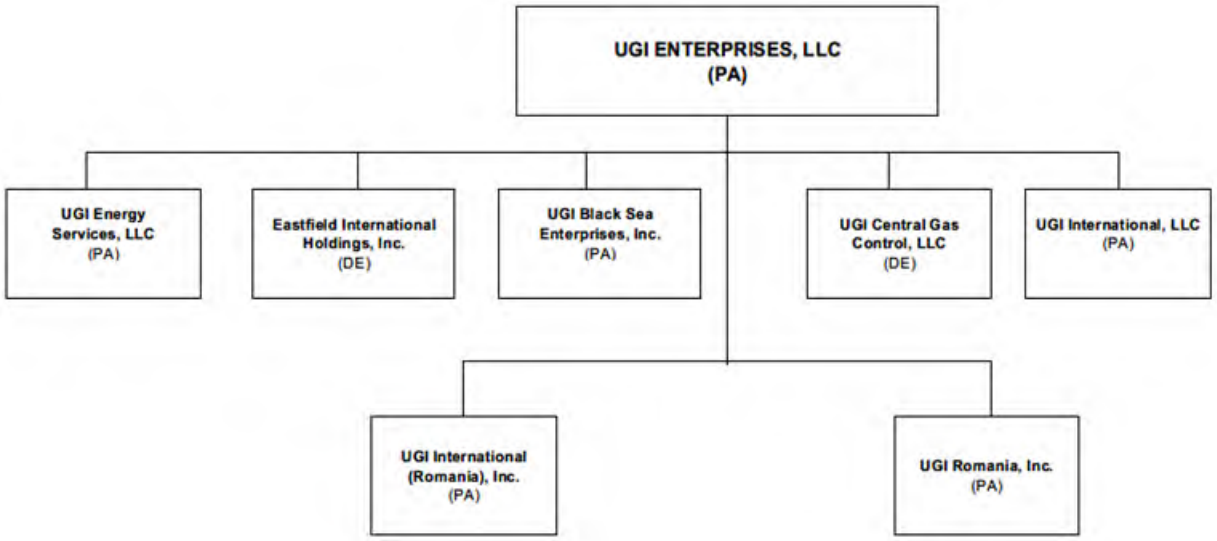
Response:

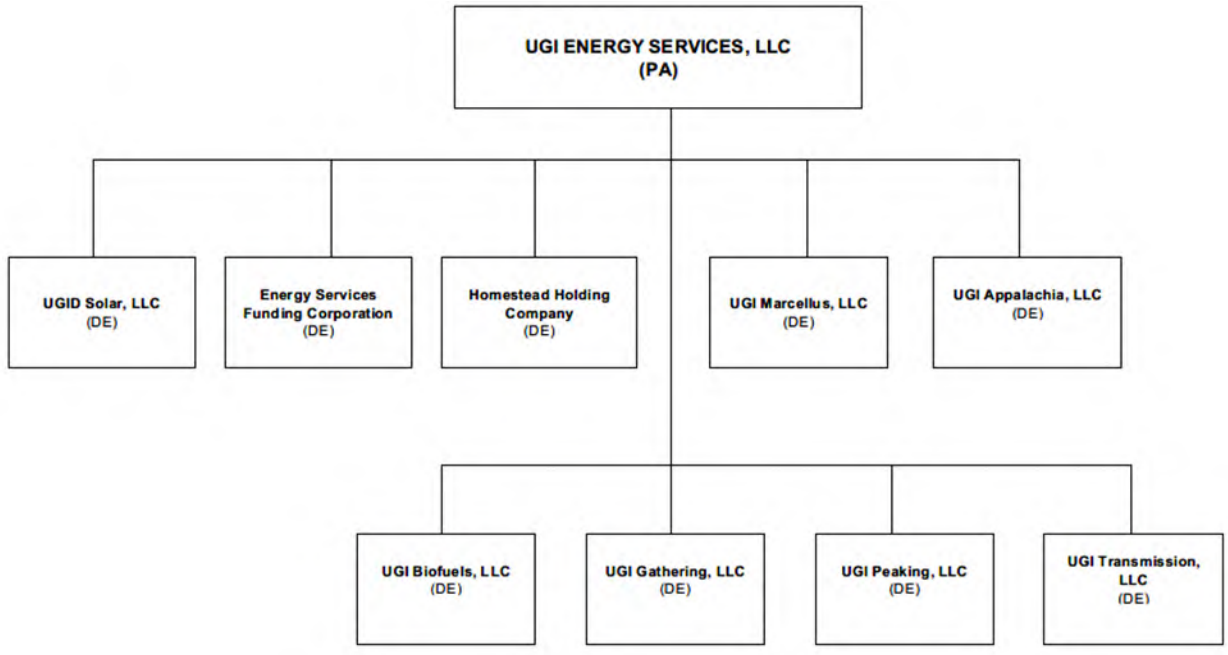
Please see Attachment II-A-24.

Prepared by or under the supervision of: Vivian K. Ressler


UGI CORPORATION
(PA)
Newbury Holding Company (DE)
UGI Enterprises, LLC (PA)
UGI Holdings, LLC (DE)
(Shell Entity)
UGI Properties, Inc. (PA)
UGI Utilities, Inc. (PA)
United Valley Insurance Company (VT)
3.47%
Vertimass, LLC (DE)
AmeriGas, Inc. (PA)
Ashtola Production Company (PA)
Mountaintop Energy Holdings LLC (DE)
100%
Vertimass EMEA B.V. (Netherlands)
AmeriGas Propane, Inc. (G.P.) (PA)
UGI Ethanol Development Corporation (PA)
Mountaineer Gas Company (WV)
Four Flags Drilling Company, Inc. (PA)


UGI UTILITIES, INC.
(PA)
Operation Share Energy Fund (PA) (Nonprofit
UGI Energy Ventures, Inc. (DE)
UGI Penn HVAC Services, Inc. (PA)
UGI Central Penn Propane, LLC (PA)


UGI ENTERPRISES, LLC
(PA)
UGI Energy Services, LLC
(PA)
Eastfield International Holdings, Inc.
(DE)
UGI Black Sea Enterprises, Inc.
(PA)
UGI Central Gas Control, LLC
(DE)
UGI International, LLC
(PA)
UGI International (Romania), Inc.
(PA)
UGI Romania, Inc.
(PA)


UGI ENERGY SERVICES, LLC
(PA)
UGID Solar, LLC
(DE)
Energy Services Funding Corporation
(DE)
Homestead Holding Company
(DE)
UGI Marcellus, LLC
(DE)
UGI Appalachia, LLC
(DE)
UGI Biofuels, LLC
(DE)
UGI Gathering, LLC
(DE)
UGI Peaking, LLC
(DE)
UGI Transmission, LLC
(DE)

II-A-25

Request:

If the utility plans to make a formal claim for a specific allowable rate of return, provide the following data in statement or exhibit form:

a. Claimed capitalization and capitalization ratios with supporting data.
b. Claimed cost of long-term debt with supporting data.
c. Claimed cost of short-term debt with supporting data.
d. Claimed cost of total debt with supporting data.
e. Claimed cost of preferred stock with supporting data.
f. Claimed cost of common equity with supporting data.

Response:

a. Please see the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and UGI Gas Exhibit B Rate of Return, Schedule 1, Page 1.

b. Please see the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and UGI Gas Exhibit B, Rate of Return, Schedule 1, Page 1, and Attachment II-A-6.

c. No claim is being made for short-term debt.

d. Please see the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and UGI Gas Exhibit B, Rate of Return, Schedule 1, Page 1, and Attachment II-A-6.

e. This subparagraph is not applicable as the Company does not have preferred stock.

f. Please see the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and UGI Gas Exhibit B, Rate of Return, Schedules 1-10.

Prepared by or under the supervision of: Dylan D'Ascendis

II-A-26

Request:

Provide the following income tax data:

a. Consolidated income tax adjustments, if applicable.

b. Interest for tax purposes (basis).

Response:

a. A consolidated tax adjustment has not been flowed through as a ratemaking deduction in the calculation of UGI Gas's federal income tax expense. In addition, the Company is no longer supplying a calculation of a hypothetical consolidated tax adjustment for the purposes of satisfying Section 1301.1(b), because Section 1301.1(b) no longer applies as of December 31, 2025. Please see the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9, for a discussion on the change in the requirement.

b. The interest tax deduction for rate making purposes is synchronized with the interest component of the capital structure.

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - II-C - Rate of Return - Gas Utilities
Delivered on January 28, 2026

II-C-1

Request:

Provide test year monthly balances for “Current Gas Storage” and notes financing such storage.

Response:

Refer to UGI Gas Exhibit A (Historic), Schedules B-6 and C-5, UGI Gas Exhibit A (Future), Schedules B-6 and C-5, and UGI Gas Exhibit A (Fully Projected Future), Schedules B-6 and C-5. All of the Company's notes can be used to finance gas storage.

Prepared by or under the supervision of: Tracy A. Hazenstab

SECTION 53.53 – BALANCE SHEET AND OPERATING STATEMENT

III-A-1

Request:

Provide a comparative balance sheet for the test year and the preceding year which corresponds with the test year date.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule B-1 for a balance sheet for each of the test years. For the preceding year which corresponds with the test year date, please refer to the response to SDR-ROR-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-2

Request:

Set forth the major items of Other Physical Property, Investments in Affiliated Companies and Other Investments.

Response:

Please see Attachment III-A-2.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
Other Physical Property, Investments in Affiliated Companies and Other Investments

		09/30/2025 balance
Account 121 Non-Utility Property	$	713,558
Account 123 Investment in Subsidiaries *	$	1,168,226
Account 124 Other Investments	$	14,858

* The balance in Account 123 primarily represents a residual equity investment in UGI Gas' inactive heating, ventilation and air conditioning service business ("HVAC").

III-A-3

Request:

Supply the amounts and purpose of Special Cash Accounts of all types, such as:

a. Interest and Dividend Special Deposits.

b. Working Funds other than general operating cash accounts.

c. Other special cash accounts and amounts (Temporary cash investments).

Response:

UGI Utilities, Inc. - Gas Division has no Special Cash Accounts as of September 30, 2025.

Prepared by or under the supervision of: Amy M. Keller

III-A-4

Request:

Describe the nature and/or origin and amounts of notes receivable, accounts receivable from associated companies, and any other significant receivables, other than customer accounts, which appear on balance sheet.

Response:

Please see Attachment III-A-4.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Accounts Receivable

FERC Account Description	(000's) 9/30/25 Balances
Accounts Receivable from Associated Companies – consisting primarily of administrative services provided to UGI Energy Services, Inc.	$ 3,176
Customer CIAC Payment Plans	5,152
Damage Repair and Other Misc. Receivables	3,507
Claims Reimbursements	8,183
Off System Sales & Delivery Service Fees	606

III-A-5

Request:

Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued, and amounts written-off in each of last three years.

Response:

Please see Attachment III-A-5.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of Reserve for Uncollectible Accounts

($ in 000's except for rate of accrual)	9/30/2023	9/30/2024	9/30/2025
Account 144 - Accumulated Provision for Uncollectible Accounts	$ 17,156	$ 13,708	$ 13,881
Method [1]	Allowance	Allowance	Allowance
Rate of Accrual	1.91%	1.67%	1.57%
Amounts Accrued - Uncollectible Expense	$ 23,142	$ 17,089	$ 17,879
Amounts Written Off (net of recoveries)	$ 22,524	$ 20,528	$ 17,632

[1] The allowance method recognizes that a percentage of each month's sales will eventually prove to be uncollectible. Consequently, a percentage of each month's sales is charged to uncollectible expense in that month and the reserve is increased. When specific accounts are written off, they are charged to the reserve account, thus decreasing the reserve.

III-A-6

Request:

Provide a list of prepayments and give an explanation of special prepayments.

Response:

Please see Attachment III-A-6.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Prepayments
FOR THE YEAR ENDED SEPTEMBER 30, 2025
(thousands of dollars)

Account 165	**9/30/25 Balances**
Insurance	$ 7,869
IS Maintenance & Services	6,804
Miscellaneous	472
PUC Assessment	3,413
Property Taxes	751
Income Taxes	3,376
Total Prepayments	$ 22,686

III-A-7

Request:

Explain in detail any other significant (in amount) current assets listed on balance sheet.

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule B-1.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-8

Request:

Explain in detail, including the amount and purpose, the deferred asset accounts that currently operate to effect or will at a later date effect the operating account supplying:

a. Origin of these accounts.

b. Probable changes to this account in the near future.

c. Amortization of these accounts currently charged to operations or to be charged in the near future.

d. Method of determining yearly amortization for the following accounts:

--Temporary Facilities
--Miscellaneous Deferred Debits
--Research and Development
--Property Losses
--Any other deferred accounts that effect operating results.

Response:

Please see Attachment III-A-8.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF DEFERRED ASSET ACCOUNTS

Account Description	(000) 9/30/25 Balances	Footnote
Deferred Recoverable Income Taxes	93,289	1
Pension and OPEB Benefit	89,979	2
Cost of Removal	26,934	3
Environmental Costs	21,565	4
Debt Issuance Costs	7,131	5
Excess Uncollectibles - COVID-19	5,072	6
Information Technology Program Costs (UNITE)	2,302	7
Rate Case	1,077	8
COVID-19 Emergency Relief Program	653	9
Total	$ 248,001	
Reconcilable Riders		
Deferred Fuel Under Collection (PGC Rider)	16,685	10
Universal Service Program Under Collection (USP Rider)	2,387	10
Energy Efficiency and Conservation (EEC Rider)	689	10
Total	$ 19,760	
Total Deferred Assets	$ 267,761	

Footnotes for Amortization Schedule

(1) Amortized over a period of 1-65 years dependent upon the nature of the cost.
(2) Amortized over the average remaining future service lives of plan participants.
(3) Amortized over a period of five years.
(4) Amortized based on annual environmental rate recovery.
Unrecovered costs are amortized annually at $3,028.
(5) Amortized over the term of the debt instruments.
(6) Will be amortized over 10 years, in accordance with the 2020 UGI Gas rate case settlement at Docket No. R-2019-3015162.
(7) Currently not amortizing.
(8) Amortized from November 2024 - October 2025.
(9) $922 was approved to be amortized in the 2022 UGI Gas rate case, Docket No. R-2021-3030218, to be completed in October 2032.
(10) Fully reconcilable rider

III-A-9

Request:

Explain the nature of accounts payable to associated companies, and note amounts of significant items.

Response:

Please see Attachment III-A-9.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES
FOR THE YEAR ENDED SEPTEMBER 30, 2025
(thousands of dollars)

Affiliate Name	9/30/2025	Nature of Payable Activity
AmeriGas Propane	277	Administrative services
UGI Energy Services	5,211	Gas purchase activity
UGI Energy Services	9,200	Collateral deposits
UGI Energy Services	99	Administrative services
UGI Energy Services	122	Engineering services
UGI Corporation	4,655	Administrative services
UGI Gas Control	645	Gas Control services
	$ 20,210	

III-A-10

Request:

Provide details of other deferred credits as to their origin and disposition policy (e.g.--amortization).

Response:

Please see Attachment III-A-10 for a detailed schedule of Deferred Credits.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Schedule of FERC 253 – Other Deferred Credits
(in Thousands)

FERC Account Description	Balance at 9/30/25	Footnote
Deferred Revenue	$ 16,407	1
Deferred CIAC	7,787	2
Restricted Share Awards	1,927	3
Uncertain Tax Position	938	4
Executive Retirement Plan	859	5
Short Term Disability & COBRA - Non Current	449	6
Long Term Disability - Non Current	249	7
Long Term Operating Lease Obligations	182	8
	$ 28,799	
Reconcilable Riders		
Distribution System Improvement Charge Over Collection (DSIC Rider)	1,030	9
Gas Delivery Enhancement Over Collection (GDE Rider)	$ 2	9
	$ 1,032	

Footnotes for Amortization Schedule

(1) Amortized over terms of agreements, which extend to various years through 2053.
(2) Will be applied to projects as construction is completed.
(3) Payout awarded at the end of the performance period.
(4) FIN48 liabilities are released when a tax year has been audited and settled or the tax year is closed under the statute of limitations. Generally, the statute of limitations is three years from the due date of the tax return.
(5) Amortized over the average remaining future service lives of plan participants.
(6) The valuation reflects the costs associated with all future disability payments, and will be relieved as disability payments are made.
(7) Adjusted quarterly based on the present value of the benefit costs to be paid over the disability term for an employee.
(8) Amortized over the life of the related lease.
(9) Fully reconcilable rider.

III-A-11

Request:

Supply basis for Injury and Damages reserve and amortization thereof.

Response:

The accrual for injuries and damages expense is designed to maintain the reserve at the proper level with respect to existing and probable claims, taking into account the insurance coverage available. UGI Gas currently has insurance coverage for commercial, general, automobile and property damages in excess of $1,000,000 per claim. Actual disbursements are charged against the reserve as expenditures are made.

Prepared by or under the supervision of: Amy M. Keller

III-A-12

Request:

Provide details of any significant reserves, other than depreciation, bad debt, injury and damages, appearing on balance sheet.

Response:

Please refer to Attachment SDR-RR-54 for details of significant reserves appearing on the balance sheet.

Prepared by or under the supervision of: Amy M. Keller

III-A-13

Request:

Provide an analysis of unappropriated retained earnings for the test year and three preceding calendar years.

Response:

All of the Company's retained earnings are unappropriated. Please see Attachment III-A-13, which reflects UGI Utilities, Inc. total retained earnings.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Consolidated
Analysis of Retained Earnings
Twelve Months Ended September 30,
(Thousands of Dollars)

Line No.		Historic 2023	Historic 2024	HTY 2025	FTY 2026	FPFTY 2027
1	Beginning Balance	$ 1,085,981	$ 1,292,471	$ 1,376,338	$ 1,510,769	$ 1,687,028
2	Net Income	206,490	218,868	213,430	236,260	253,839
3	Common Stock Dividends	-	(135,000)	(79,000)	(60,000)	(60,000)
4	Ending Balance	$ 1,292,471	$ 1,376,338	$ 1,510,769	$ 1,687,028	$ 1,880,868

III-A-14

Request:

Provide schedules and data in support of the following working capital items:

a. Prepayments--List and identify all items
b. Federal Excise Tax accrued or prepaid
c. Federal Income Tax accrued or prepaid
d. Pa. State Income Tax accrued or prepaid
e. Pa. Gross Receipts Tax accrued or prepaid
f. Pa. Capital Stock Tax accrued or prepaid
g. Pa. Public Utility Realty Tax accrued or prepaid
h. State sales tax accrued or prepaid
i. Payroll taxes accrued or prepaid
j. Any adjustment related to the above items for ratemaking purposes.

Response:

Please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4, and the response to III-A-6. In addition, please see the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, and the Direct Testimony of Amy M. Keller, UGI Statement No. 5.

Prepared by or under the supervision of: Amy M. Keller

III-A-15

Request:

Supply an exhibit supporting the claim for working capital requirement based on the lead-lag method.

a. Pro forma expenses and revenues are to be used in lieu of book data for computing lead-lag days.

b. Respondent must either include sales for resale and related expenses in revenues and in expenses or exclude from revenues and expenses. Explain procedures followed (exclude telephone).

Response:

Please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4 and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5.

Prepared by or under the supervision of: Amy M. Keller

III-A-16

Request:

Provide detailed calculations showing the derivation of the tax liability offset against gross cash working capital requirements.

Response:

Please refer to UGI Gas Schedule C-4 within Exhibit A (Historic), Exhibit A (Future), Exhibit A (Fully Projected).

Prepared by or under the supervision of: Darin T. Espigh

III-A-17

Request:

Prepare a Statement of Income for the various time frames of the rate proceeding including:

Col. 1--Book recorded statement for the test year.
2--Adjustments to book record to annualize and normalize under present rates.
3--Income statement under present rates after adjustment in Col. 2
4--Adjustment to Col. 3 for revenue increase requested.
5--Income statement under requested rates.

a. Expenses may be summarized by the following expense classifications for purposes of this statement:

Operating Expenses (by category)
Depreciation
Amortization
Taxes, Other than Income Taxes
Total Operating Expense
Operating Income Before Taxes
Federal Taxes
State Taxes
Deferred Federal
Deferred State
Income Tax Credits
Other Credits
Other Credits and Charges, etc.
Total Income Taxes
Net Utility Operating Income
Other Income & Deductions
Other Income
Detailed listing of Other Income used in Tax Calculation
Other Income Deduction
Detailed Listing
Taxes Applicable to Other Income and Deductions
Listing Income Before Interest Charges
Listing of all types of Interest Charges and all amortization of Premiums and/or Discounts and Expenses on Debt issues

III-A-17 (Continued)

Total Interest
Net Income After Interest Charges

(Footnote each adjustment to the above statements with explanation in sufficient clarifying detail.)

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), schedules in Section D, for the Company's presentation of the requested Statements of Income and adjustments to operating revenues and expenses.

Please refer to the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 4, and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5, for explanations of the Statements of Income and adjustments to operating revenues and expenses depicted in the Section D schedules of UGI Gas Exhibit A (Historic), (Future) and (Fully Projected), the underlying sources of budgeted information, and the basis for the adjustments.

Please refer to the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and related UGI Gas Exhibit B, for the derivation of the weighted average cost of debt used in the Company's debt interest synchronization adjustment, including the treatment of debt issuance expense, premiums and discounts used in calculating the effective cost rate for each series of long-term debt.

Please refer to the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9, for an explanation of the Company's income tax adjustments.

Please refer to the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10, for an explanation on the derivation of future test year and fully projected year sales and revenues.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-18

Request:

Provide comparative operating statements for the test year and the immediately preceding 12 months showing increases and decreases between the two periods. These statements should supply detailed explanation of the causes of the major variances between the test year and preceding year by detailed account number.

Response:

Please refer to Attachment III-A-18 for the exhibit of comparative operating statements.

Explanations of major variances (defined as amounts greater than $1,000 and 10%) are shown below in ($000's):

Gas Utility Revenues - Increase due to higher send out volume for residential and commercial classes (primarily related to colder weather) and higher purchased gas cost rates.

Other Operating Revenues - Increase primarily due to higher off system sales (FERC 4950) ($39,809), partially offset by lower customer interest revenue (FERC 4950) (-$4,471).

Operating Expense - Increase driven primarily by increases in operations wages ($4,708) and contract labor ($1,009).

Storage, Transportation and Other - Increase due to higher send out volume for residential and commercial classes (primarily related to colder weather) and higher costs related to off system sales.

Interest Income/Interest Expense - Change primarily related to PGC interest - interest expense in 2024 vs. interest income in 2025 ($4,460 variance within FERC 4190).

Miscellaneous Income/Expense - Increase due to higher environmental expense of $2,611 in 2025. This amount is related to sites outside of Pennsylvania and is not included in UGI Gas's claimed costs.

III-A-18 (Continued)

Tax Expense - Lower income tax expense primarily driven by lower income before taxes.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Comparative Statements of Income
(thousands of dollars)

	12 Months Ended 9/30/2024	12 Months Ended 9/30/2025	Variance
Revenues			
Gas Utility Revenues	$ 1,016,733	$ 1,136,989	$ 120,256
Other Operating Revenues	140,248	174,026	33,778
Total Operating Revenue	1,156,982	1,311,015	154,034
Expenses			
Operating Expense	48,124	55,839	7,715
Maintenance Expense	32,777	35,902	3,125
Customer Accounts Operations Expense	43,543	44,076	532
Customer Service, Information and Sales Expense	2,670	3,546	876
Admin and General Operation Expense	100,673	98,441	(2,232)
Depreciation and Amortization Expense	133,560	142,917	9,357
Other taxes	13,419	13,228	(191)
Storage, Transportation and Other	433,284	573,097	139,813
Interest Income/Interest Expense	2,196	(1,924)	(4,120)
Miscellaneous Income/Expense	360	2,566	2,207
Long Term Debt Interest	77,300	83,930	6,629
Total Expenses before Taxes	887,907	1,051,618	163,711
Income Before Taxes	269,075	259,398	(9,677)
Tax Expense	61,564	55,657	(5,907)
Net Income	$ 207,511	$ 203,741	$ (3,770)

III-A-19

Request:

List extraordinary property losses as a separate item, not included in operating expenses or depreciation and amortization. Sufficient supporting data must be provided.

Response:

None.

Prepared by or under the supervision of: Amy M. Keller

III-A-20

Request:

Supply detailed calculations of amortization of rate case expense, including supporting data for outside services rendered. Provide the items comprising the rate case expense claim (include the actual billings or invoices in support of each kind of rate case expense), the items comprising the actual expenses of prior rate cases and the unamortized balances.

Response:

The Company's rate case expense claim is based on the normalization of projected rate case expenditures. For details, please see UGI Gas Exhibit A (Fully Projected), Schedule D-10. Historic expenditures from the Company's last rate case at Docket No. R-2024-3052716 are shown in Attachment III-A-20.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
Rate Case Expense
for Docket No. R-2024-3052716

External Consultants	$	530,247
External Legal	$	412,794
Administrative and Printing	$	129,154
Total	$	1,072,195

III-A-21

Request:

Submit detailed computation of adjustments to operating expenses for salary, wage and fringe benefit increases (union and non-union merit, progression, promotion and general) granted during the test year and six months subsequent to the test year. Supply data showing for the test year:

a. Actual payroll expense (regular and overtime separately) by categories of operating expenses, i.e., maintenance, operating transmission, distribution, other.

b. Date, percentage increase, and annual amount of each general payroll increase during the test year.

c. Dates and annual amounts of merit increases or management salary adjustments.

d. Total annual payroll increases in the test year.

e. Proof that the actual payroll plus the increases equal the payroll expense claimed in the supporting data (by categories of expenses).

f. Detailed list of employe benefits and cost thereof for union and non-union personnel. Any specific benefits for executives and officers should also be included, and cost thereof.

g. Support the annualized pension cost figures.

   (i) State whether these figures include any unfunded pension costs. Explain.

   (ii) Provide latest actuarial study used for determining pension accrual rates.

h. Submit a schedule showing any deferred income and consultant fee to corporate officers or employees.

Response:

a - f. Refer to UGI Gas Exhibit A (Fully Projected), Schedules D-7 and D-14 and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5.

III-A-21 (Continued)

g. Refer to Attachment III-A-21 for the latest actuarial report showing pension accrual rates, which has been uploaded separately via the Commission's SharePoint site. The materials will be served upon the parties via a secure OneDrive link.

h. There are no significant deferred income and consultant fees to corporate officers or employees.

Prepared by or under the supervision of: Amy M. Keller

III-A-22

Request:

Supply an exhibit showing an analysis, by functional accounts, of the charges by affiliates (Service Corporations, etc.) for services rendered included in the operating expenses of the filing company for the test year and for the 12-month period ended prior to the test year:

a. Supply a copy of contracts, if applicable.
b. Explain the nature of the services provided.
c. Explain basis on which charges are made.
d. If charges allocated, identify allocation factors used.
e. Supply the components and amounts comprising the expense in this account.
f. Provide details of initial source of charge and reason thereof.

Response:

Refer to Attachment III-A-22.1 for listings of applicable Gas Purchase Agreements, Asset Management Agreements and Affiliated Interest Agreements which have been previously authorized by the Commission. Refer to Attachments III-A-22.2(a) - (k) for copies of the Affiliated Interest Agreements which have been previously authorized by the Commission, which have been uploaded separately via the Commission's SharePoint site. The materials will be served upon the parties via a secure OneDrive link.

See Attachment III-A-22.3 for a listing of charges from affiliates for services rendered. This listing includes the affiliate providing the service, the nature of the service, the amounts charged for Fiscal 2023 - Fiscal 2027 (Fiscal 2026 and Fiscal 2027 are planned amounts), the FERC functional account(s) where the charges are recorded, and the allocation factor (if applicable).

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
List of Natural Gas Purchase Agreements and Asset Management Agreements as Presented to the PUC

Affiliate Name & Contract	Contract Effective Date	Contract Termination Date
UGI Energy Services, LLC		
Natural Gas Purchase Agreement	5/1/2017	30 days written notice
Natural Gas Supply & Delivery Contract (UGI-CO-1013) 97,994 MDQ	11/1/2020	10/31/2038
Natural Gas Supply & Delivery Contract (UGI-CO-1014) 25,000 MDQ	11/1/2021	10/31/2036
Peaking Delivery Service (UGI-P-1012) 23,632 MDQ	11/1/2016	3/31/2031
Peaking Delivery Service (UGI-P-1010) 106,465 MDQ	11/1/2015	3/31/2030
Peaking Delivery Service (UGI-P-1014) 40,573 MDQ	11/1/2018	3/31/2033
Natural Gas Supply & Delivery Contract (PNG-CO-1012) 36,169 MDQ	11/1/2018	10/31/2033
Peaking Delivery Service (PNG-P-1003) 21,772 MDQ	11/1/2016	3/31/2031
Transportation Service Agreement (Carverton Road) 120,000 MDQ	12/26/2013	12/25/2033
Peaking Delivery Service (CPG-P-1006) 4,750 MDQ	11/1/2015	3/31/2030
Peaking Delivery Service (CPG-P-1007) 5,000 MDQ	11/1/2018	3/31/2033
Peaking Delivery Service (CPG-P-1008) 2,519 MDQ	11/1/2018	3/31/2033
Peaking Delivery Service (UGI-P-1016) 162,177 MDQ	11/1/2021	3/31/2036
Peaking Delivery Service (UGI-P-1017) 72,299 MDQ	11/1/2021	3/31/2036
Peaking Delivery Service (UGI-P-1020) 40,000 MDQ	12/1/2024	3/31/2039
Asset Management Agreement on Columbia Pipeline	11/1/2025	10/31/2028
Natural Gas Supply & Delivery Contract (UGI-CO-1017) 17,963 MDQ	11/1/2025	3/31/2026
Natural Gas Supply & Delivery Contract (UGI-CO-1018) 15,003 MDQ	4/1/2026	3/31/2030
UGI Storage Company		
NNS Firm Delivery Contract 8,792 MDQ	4/1/2011	3/31/2027
FSS Firm Storage Contract 879,200 SCQ	4/1/2011	3/31/2027

These agreements have been provided to the PA PUC in separate proceedings.

UGI Utilities, Inc. - Gas Division
List of Affiliated Interest Agreements as Presented to the PUC

Attachment #	Affiliate	Effective Dates	Docket #	Details
III-A-22.2(a)	UGI Corporation	Dec-25	G-2023-3045143 & G-2024-3050728	Shared Services Affiliate Agreement between UGI Utilities, Inc. ("UGI Utilities") and UGI Corporation and its subsidiaries / affiliates ("UGI Corp") under which UGI Utilities and UGI Corp may provide certain management, administrative and other services to each other.
III-A-22.2(b)	UGI Corporation	Jul-03	G-00031008	Affiliate Agreement between UGI Utilities, Inc. and UGI Corporation and its subsidiaries under which Utilities would provide pipeline engineering, construction, maintenance and related services to UGI Companies.
III-A-22.2(c)	UGI Energy Services, LLC	Apr-04	G-00041075	Affiliate Interest Agreement regarding ground to be leased by UGI Energy Services, LLC from UGI Utilities, Inc. and office space to be leased by UGI Utilities, Inc. from UGI Energy Services, LLC.
III-A-22.2(d)	UGI Energy Services, LLC	Aug-97	G-00970552	This is an Agreement whereby UGI Utilities, Inc. would buy gas from or sell gas to GASMARK (now UGI Energy Services, LLC) at prevailing market rates.
III-A-22.2(e)	UGI Energy Services, LLC	Mar-99	G-00980646	Affiliate Agreement whereby UGI Utilities, Inc. would buy electric generation from Energy Services at or below prevailing market rates, for its own use at facilities throughout its service territories.
III-A-22.2(f)	UGI Corporation	Aug-22	G-2022-3033065	Affiliate Agreement between UGI Utilities, Inc. and UGI Corporation and its subsidiaries under which Utilities would receive various construction related engineering and project management services from Affiliated UGI Companies.
III-A-22.2(g)	United Valley Insurance Co.	Jun-93	G-00930344	Affiliate Interest Agreement for insurance coverage through United Valley Insurance Co. Coverage through the affiliate is not mandatory and may be purchased through other independent companies when costs or coverage are more advantageous.
III-A-22.2(h)	UGI Sunbury, LLC	Jun-15	G-2015-2467129	Affiliated Interest Agreement between UGI Utilities, Inc. and UGI Sunbury, LLC regarding the Sunbury Pipeline.
III-A-22.2(i)	UGI Central Gas Control, LLC	Oct-20 – Sep-30	G- 2020-3021989	Affiliated Interest Agreement between UGI Utilities, Inc. - Gas Division ("UGI Gas") and UGI Central Gas Control, LLC (" UGI Gas Control") under which UGI Gas receives gas control services from UGI Gas Control and UGI Gas provides certain IT and licensing provisions to UGI Gas Control.
III-A-22.2(j)	UGI Energy Services, LLC	Apr-21	G-2021-3024552	Affiliated Interest Agreement between UGI Utilities, Inc. – Electric & Gas Divisions and UGI Energy Services, LLC to sub-lease office space.
III-A-22.2(k)	UGI Energy Services, LLC	Nov-21	G-2021-3028753	Affiliated Interest Agreement between UGI Utilities, Inc. and UGI Energy Services, LLC regarding the Auburn Gathering System.

UGI Utilities, Inc. - Gas Division
Charges by Affiliates - Services Rendered
For the Fiscal Years Ended September 30, 2023 through 2027
$s in Thousands

		2023	2024	2025	2026	2027	FERC Functional Account(s)	Allocation Factor	
1)	UGI Central Gas Control								
	Gas Control Services	$ 2,634	$ 3,014	$ 2,475	$ 3,008	$ 3,159	871	Signal count	
2)	United Valley Insurance Company								
	Insurance coverage	$ 1,173	$ 1,534	$ 1,612	$ 1,612	$ 1,612	925	By policy	(a)
3)	AmeriGas								
	Administrative Services	$ 59	$ 47	$ 74	$ 74	$ 582	(d)	(e)	
4)	UGI Energy Services, LLC								
	Natural Gas Purchases	$ 249,255	$ 216,343	$ 267,198	$ 270,000	$ 270,000	804	N/A	(b)
	Building sub-lease	$ 569	$ 636	$ 703	$ 726	$ 745	107, 101	Lease agreement	(c)
	Auburn Capacity Lease	$ 565	$ 573	$ 578	$ 584	$ 590	881	Lease agreement	
	Administrative Services	$ 62	$ 50	$ 68	$ 60	$ 63	(d)	(e)	
	Construction & engineering services	$ 8	$ 480	$ 431	$ 431	$ 431	107, 101	N/A	(b)
5)	UGI Corporation								
	Administrative services	$ 26,025	$ 25,156	$ 32,913	$ 32,884	$ 33,071	(d)	(f)	
	Insurance coverage	$ 7,526	$ 9,359	$ 9,487	$ 10,490	$ 11,449	(d)	By policy	

N/A Not Applicable

(a) United Valley Insurance is a UGI-owned Captive Insurance Company, from which UGI purchases a portion of its excess liability insurance. This insurance is reinsured through other insurance companies, and United Valley does not retain risk. United Valley portion of total insurance coverage for 2026 and 2027 is assumed to be consistent with the amount from 2025.

(b) 2026 and 2027 purchases from UGI Energy Services, LLC are estimated based on 2025 actuals.

(c) UGI Utilities, Inc. subleases building space from UGI Energy Services, LLC, as explained at Attachment III-A-22.2. This building space is used exclusively for the IT development project teams and is therefore capitalized as part of the project costs within 107 (while in progress) and 101 (when complete).

(d) Administrative services are assigned to various A&G FERC accounts, based on the nature of the underlying cost. Insurance coverage is recorded to FERC 925. For both the administrative services and the insurance coverage, a portion of the amounts shown here is capitalized.

(e) Administrative services from UGI Energy Services, LLC and AmeriGas primarily relate to IT support. Allocation factor used for these IT support costs is primarily based on the number of users of the software for which the support is provided.

(f) Allocation factor used for administrative services from UGI Corporation is primarily Modified Wisconsin Formula ("MWF"), with other allocation rates used based on the nature of the services.

III-A-23

Request:

Describe costs relative to leasing equipment, computer rentals, and office space, including terms and conditions of the lease. State method for calculating monthly or annual payments.

Response:

Please see Attachment III-A-23.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Costs Relative to Leasing Equipment, Computer Rental and Office Space
12 Months Ended 9/30/2025
(000's)

	Annual Payments	Method of Computing Payment	Terms of Lease or Rental Agreement
Real Estate	$ 778	Monthly payments per lease or rental agreements. Percentage applied from Modified Wisconsin Formula for leases of shared properties.	2020 - 2028
Equipment	8	Monthly payments per lease or rental agreements. Percentage applied from Modified Wisconsin Formula for leases of shared assets.	2022 - 2026
Total	$ 786		

Note: Balances above include long-term leases only (Original Terms of 12 months or more)

III-A-24

Request:

Submit detailed calculations (or best estimates) of the cost resulting from major storm damage.

Response:

No major storm damages have been recorded in the last five fiscal years. Accordingly, no damages are included in the future or fully projected future test year claims.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-25

Request:

Submit details of expenditures for advertising (National and Institutional and Local media). Provide a schedule of advertising expense by major media categories for the test year and the prior two comparable years with respect to:

a. Public health and safety
b. Conservation of energy
c. Explanation of Billing Practices, Rates, etc.
d. Provision of factual and objective data programs in educational institutions
e. Other advertising programs
f. Total advertising expense

Response:

Please see Attachment III-A-25.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
ADVERTISING EXPENSES
FOR THE YEARS ENDED SEPTEMBER 30, 2023 THROUGH 2027
(in US Dollars)

		FY2023	FY2024	FY2025	FY2026	FY2027
Public Health & Safety	Print/Digital	$ 24,703	$ 452,992	$ 377,705	$ 379,624	$ 401,225
Public Health & Safety	Radio	$ -	$ 50,986	$ 85,912	$ 176,400	$ 176,400
Public Health & Safety	TV	$ -	$ -	$ -	$ -	$ -
Public Health & Safety	Bill Insert	$ -	$ 472,874	$ 287,946	$ 303,891	$ 321,183
Public Health & Safety	Other*	$ 200	$ 48,750	$ 135,506	$ 197,660	$ 191,916
Conservation of Energy	Print/Digital	$ 83,604	$ 72,161	$ 235,414	$ 240,467	$ 244,000
Conservation of Energy	Radio	$ -	$ 2,500	$ -	$ -	$ -
Conservation of Energy	TV	$ -	$ -	$ -	$ -	$ -
Conservation of Energy	Bill Insert	$ 21,770	$ 879	$ -	$ 26,733	$ 28,515
Conservation of Energy	Other*	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	Print/Digital	$ 36,964	$ 26,669	$ 35,983	$ 36,298	$ 37,350
Explanation of Bill Practices, Rates, Etc.	Radio	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	TV	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	Bill Insert	$ 342,186	$ 151,608	$ 130,844	$ 269,993	$ 280,320
Explanation of Bill Practices, Rates, Etc.	Other*	$ -	$ -	$ -	$ -	$ -
				$ -	$ -	$ -
Data Programs in Educational Institutions	Print/Digital	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Radio	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	TV	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Bill Insert	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Other*	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	Print/Digital	$ 163,130	$ 127,006	$ 130,784	$ 190,124	$ 189,249
Other Advertising Programs	Radio	$ -	$ -	$ 2,995	$ -	$ -
Other Advertising Programs	TV	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	Bill Insert	$ 15,916	$ -	$ -	$ -	$ -
Other Advertising Programs	Other*	$ 486,098	$ 242,799	$ 152,974	$ 168,655	$ 191,149
SUMMARY BY MEDIA						
Total Advertising Expenses	Print/Digital	$ 308,401	$ 678,829	$ 779,885	$ 846,513	$ 871,824
Total Advertising Expenses	Radio	$ -	$ 53,486	$ 88,907	$ 176,400	$ 176,400
Total Advertising Expenses	TV	$ -	$ -	$ -	$ -	$ -
Total Advertising Expenses	Bill Insert	$ 379,872	$ 625,360	$ 418,790	$ 600,617	$ 630,019
Total Advertising Expenses	Other*	$ 486,298	$ 291,550	$ 288,480	$ 366,315	$ 383,065
SUMMARY BY CATEGORY						
Public Health & Safety	All	$ 24,903	$ 1,025,602	$ 887,069	$ 1,057,575	$ 1,090,724
Conservation of Energy	All	$ 105,374	$ 75,540	$ 235,414	$ 267,200	$ 272,515
Explanation of Bill Practices, Rates, Etc.	All	$ 379,150	$ 178,277	$ 166,827	$ 306,291	$ 317,671
Data Programs in Educational Institutions	All	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	All	$ 665,144	$ 369,805	$ 286,752	$ 358,779	$ 380,397
TOTAL		$ 1,174,571	$ 1,649,225	$ 1,576,062	$ 1,989,845	$ 2,061,307

* Other advertising includes other mass media, website and branded giveaways.

III-A-26

Request:

Provide a list of reports, data, or statements requested by and submitted to the Commission during and subsequent to the test year.

Response:

Please see Attachment III-A-26.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. – Gas Division
List of reports, data or statements requested by and submitted to the Commission during and subsequent to the test year.

- Test Year Plant Reporting Obligation. (Docket No. R-2024-3052716, Final Order entered 9/11/2025)
- Weather Normalization Pilot Program Reporting. (Docket No. R-2021-3030218, Final Order entered 9/15/22. Reporting was revised at Docket No. R-2024-3052716, Final Order entered 9/11/2025)
- PUC Annual Report
- Universal Service Program Reconciliations
- Section 1307(f) Annual Purchased Gas Cost Filings – Book I & II
- Annual Purchase Gas Cost Compliance Filing
- Annual Gas Rate Comparison Report
- Integrated Resource Planning Report (Preliminary, Annual, Bi-Annual Reporting)
- Quarterly Purchase Gas Cost Filing
- Gas Switching Report/Choice Switching Report/Monthly Gas Switching Chart
- Annual Report on Unaccounted For Gas
- Residential and Commercial Price-to-Compare Report
- Quarterly Financial and Statistical Report
- P.U.C. Regulatory Assessment on Gross Receipts
- Informal compliant replies
- 52 PA Code 56.231 – Collection Results for Residential and Small Commercial Customers (Monthly and Annual)
- Quality of Service – Benchmark and Standards Report - including Metrix/Matrix
- PA Code 58.15 LIURP annual program evaluation report and Spending and Budget report
- 52 PA Code 62.6 - Universal Service Program Impact Evaluation
- Annual Conservation Plan – Status of Existing Conservation Activities
- 52 PA Code 56.100 (4) and 56.100 (5) – Cold Weather Survey of premises where heat related service is terminated during the year and resurvey of prior year's account not restored.
- Customer Assistance Program (CAP) Report
- Section 1410.1(4) – Medical Certificates and renewals submitted and accepted by the Company
- Section 1410.1(3) – Accounts Exceeding $10,000 in Arrearages
- Quarterly Rate of Return Filing
- Annual Depreciation Report
- Public Utility Security Planning & Readiness Self-Certification Form
- Gas Supply and Demand Report
- Payment Agreement Report
- Gas Delivery Enhancement Rider Rate Filing
- 66 PA Code 1412 – Collections Data – Ch. 14 Reporting – Attachment A

UGI Utilities, Inc. – Gas Division
List of reports, data or statements requested by and submitted to the Commission during and subsequent to the test year.

- Annual Statistical Report
- Natural Gas Utility Update Report
- Long Term Infrastructure Improvement Plan
- Annual Asset Optimization Plan
- Annual DOT Reports
- Meter Test Reports and Letter Filing
- Annual Diversity Report
- Quality of Service Transaction Survey
- Bi-Annual LIURP Report
- Annual Hardship Fund Report
- State Tax Adjustment Surcharge Filing
- Universal Service Surcharge Quarterly Filing
- Universal Service Surcharge Reporting Requirements
- USP Impact Evaluation
- Annual Conservation Plan - IRP - Status of Existing Conservation Activities
- LIHEAP Performance Management Report
- CAP Collaboratives
- CAP Credit Report
- Distribution System Improvement Charge (DSIC)
- Combined Heat and Power (CHP) Report
- EE&C Annual Rate Filing
- EE&C Annual Over/Under Reconciliation
- Annual Report – Natural and Other Gas Transmission and Gathering Systems
- Transmission Integrity Management Notifications
- Cast Iron and Bare Steel Status Report
- Safety Related Condition Report
- Incident Report – Gas Distribution/Transmission Systems
- Supply Regulatory Inventory
- Low-Income Usage Reduction Program Year-end Status Report
- EAP Winter Season Annual Report
- Quarterly Mechanical Tee Reporting
- Natural Gas-fired Electric Generation Customers receiving Distribution Service from NGDCs
- Universal Service and Energy Conservation Plan (every 5 years)
- Refunds of LIHEAP Benefits

UGI Utilities, Inc. – Gas Division
List of reports, data or statements requested by and submitted to the Commission during and subsequent to the test year.

- Refunds of LIHEAP Benefits
- Capital Investment Plan Report (every 5 years)
- Service Life Study Report (every 5 years)
- Significant Updates to Commodity Risk Management Policy
- Annual Call Center Performance Reports (Docket No. R-2024-3052716, Final Order entered 9/11/2025)

III-A-27

Request:

Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for by the Company and the cost thereof.

Response:

None are being claimed.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-28

Request:

Submit a schedule showing, by major components, the expenditures associated with Outside Services Employed, Regulatory Commission Expenses and Miscellaneous General Expenses, for the test year and prior two comparable years.

Response:

Please see Attachment III-A-28.1 for account 930.2 - Miscellaneous General Expenses.

Please see Attachment III-A-28.2 for account 923 - Outside Services Employed.

Please see attachment III-A-28.3 for account 928 - Regulatory Commission Expenses. 2027 costs are associated with the current rate case filing and the actual claimed amount is shown at Exhibit A, Fully Projected, Schedule D-10.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of Account 930.2 - Miscellaneous General Expenses
For the Fiscal Years Ending September 30, 2025 through 2027
(thousands of dollars)

Expenditure Type	**2023**	**2024**	**2025**	**2026**	**2027**
Association Dues	1,019	970	1,038	1,034	1,095
Company Memberships	463	117	315	149	151
Industry Research	-	-	172	366	371
Company Use of Fuel*	1,809	-	-	-	-
Employee Benefits Expense	134	74	26	-	-
Other Expenses	(438)	22	-	-	-
Total	**2,987**	**1,183**	**1,552**	**1,550**	**1,617**

*2024 - 2027 expenses associated with Company Use of Fuel have been remapped to FERC 9320

UGI Utilities, Inc. - Gas Division
Schedule of Account 923 - Outside Services Employed
For the Fiscal Years Ending September 30, 2023 through 2027
(thousands of dollars)

Expenditure Type	**2023**	**2024**	**2025**	**2026**	**2027**
Accounting, Audit and Tax	729	782	1,836	985	989
Corporate Allocations	7,543	8,274	12,487	12,057	11,182
Environmental	737	621	738	605	609
Insurance Premiums[(1)]	5,476	1	-	-	-
Legal & Other Professional Services	9,516	9,496	9,498	3,921	3,893
Information Services	6,419	2,469	2,774	3,505	3,670
Miscellaneous	93	95	102	171	112
Total	**30,514**	**21,740**	**27,435**	**21,245**	**20,455**

(1) Insurance premium expense was included in FERC 923 in 2023, but in FERC 925 for 2024 - 2027.

UGI Utilities, Inc. - Gas Division
Schedule of Account 928 - Regulatory Commission Expenses
For the Fiscal Years Ending September 30, 2023 through 2027
(thousands of dollars)

Expenditure Type	**2023**	**2024**	**2025**	**2026**	**2027**
Rate Case Amortization	387	433	36	1,160	2,297
Total	**387**	**433**	**36**	**1,160**	**2,297**

III-A-29

Request:

Submit details of information covering research and development expenditures, including major projects within the company and forecasted company programs.

Response:

UGI Gas has included approximately $371,457 in the fully projected future test year claim for supporting a number of research and development program areas through membership with the Operations Technology Development Company ("OTD"), an associated company of the Gas Technology Institute. OTD is a collaborative effort to develop advanced technologies for the natural gas industry.

UGI Gas currently has an active membership agreement with OTD. This membership supports access to best practices related to the natural gas industry technologies, as well as furthering support for newer or emerging gas technologies; all of which stand to benefit natural gas customers by enhancing efficient operational and equipment standards which support the safe, reliable and efficient delivery and utilization of natural gas.

Prepared by or under the supervision of: Hans G. Bell

III-A-30

Request:

Provide a detailed schedule of all charitable and civic contributions by recipient and amount for the test year.

Response:

Please see Attachment III-A-30 for a schedule of all charitable and civic contributions made for UGI Gas for the fiscal year ending September 30, 2025. No claim is being made for charitable and civic contributions.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Charitable and Civic Contributions
For The Year Ended September 30, 2025

Organization Name		2025
OPERATION SHARE	$	584,500
READING IS FUNDAMENTAL INC		166,333
WILKES UNIVERSITY		60,000
UNITED WAY OF BERKS COUNTY		60,000
THE PENNSYLVANIA STATE UNIVERSITY		60,000
AMERICAN RED CROSS		54,000
UNITED WAY OF WYOMING VALLEY		53,941
LANCASTER EDUCATION FOUNDATION		50,000
UNITED WAY OF LACKAWANNA & WAYNE CO		44,200
UNITED WAY OF LANCASTER COUNTY		35,300
UNITED WAY OF THE CAPITAL REGION		30,500
THADDEUS STEVENS FOUNDATION		30,000
THE SALVATION ARMY		26,250
THE JOSHUA GROUP		25,000
PENNSYLVANIA COLLEGE OF TECH FNDN		25,000
BIG BROTHERS BIG SISTERS OF SCPA		23,000
JUNIOR ACHIEVEMENT OF NORTHEASTERN PA		21,250
BRIDGE EDUCATIONAL FOUNDATION		21,111
UNITED WAY OF GREATER LEHIGH VALLEY		20,500
LEHIGH CARBON COMMUNITY COLL FNDN		20,000
DA VINCI DISC CNTR OF SCI & TECH		20,000
POCONO MOUNTAINS UNITED WAY		17,000
LANCASTER SCIENCE FACTORY		15,000
COMMUNITIES IN SCHS OF EASTERN PA INC		15,000
COCALICO EDUCATION FOUNDATION		15,000
KIDSPEACE CORP		15,000
LANCASTER COUNTY CAREER & TECH FNDN		15,000
OPPORTUNITY HOUSE		12,241
SKILLSUSA COUNCIL		11,000
ALVERNIA UNIVERSITY		10,500
SPANISH AMERICAN CIVIC ASSOC		10,000
DAUPHIN COUNTY LIBRARY SYSTEM		10,000
BERKS COUNTY COMMUNITY FNDN		10,000
THE CHALLENGE PROGRAM, INC		10,000
READING SCIENCE CENTER		10,000
UNITED WAY OF CARLISLE & CUMBERLAND COUNTY		10,000
FOUNDATION OF THE COLUMBIA MONTOUR		10,000
UNITED WAY OF PENNSYLVANIA		10,000
WITF INC		10,000
JUNIOR ACHIEVEMENT OF S CENTRAL PA		10,000
SOLANCO EDUCATION FOUNDATION		10,000
MISCELLANEOUS CONTRIBUTIONS UNDER $10,000		342,214
Total	**$**	**2,008,840**

III-A-31

Request:

Provide a detailed analysis of Special Services--Account 795.

Response:

Gas account 795 has no activity.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-32

Request:

Provide a detailed analysis of Miscellaneous General Expense--Account No. 801.

Response:

UGI Gas has not recorded activity to account 801 for the last five fiscal years and has no amounts allocated to this account in the FTY or FPFTY. UGI Gas does, however, capture Miscellaneous General Expense under account 930.2. For an analysis of that account's activity, please refer to the response to III-A-28.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-33

Request:

Provide a labor productivity schedule.

Response:

Please see Attachment III-A-33.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Labor Productivity Schedule
For Fiscal Years 2025 - 2027

	HTY Actual FY-2025	FTY Estimate FY-2026	FPFTY Estimate FY-2027
Sales (Mcf)	321,628,752	338,968,445	339,204,231
Number of Employees	1,533	1,520	1,541
Number of Hours Worked	3,189,322	3,161,816	3,205,543
Miles of Main- Total	12,700	12,750	12,800
Miles of Main-Distribution	12,437	12,487	12,537
Miles of Main- Transmission	263	263	263
Number of Customers	693,759	700,430	706,232
Mcf Sales per Employee	209,759	222,990	220,102
Per Hours Worked	101	107	106
Miles of Main per Employee-Total	8	8	8
Miles of Main per Employee-Distribution	8	8	8
Miles of Main per Employee- Transmission	0	0	0
Customers per Employee	452	461	458

III-A-34

Request:

List and explain all non-recurring abnormal or extraordinary expenses incurred in the test year which will not be present in future years.

Response:

Test year expenses that are non-recurring, extraordinary or do not occur yearly, but over an extended period of years, are explained and adjusted in Section D of UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected).

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-35

Request:

List and explain all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years. (e.g.--Non-yearly maintenance programs, etc.)

[Responses shall be submitted and identified as exhibits.]

Response:

For adjustments to operating expenses, please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D, and the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-36

Request:

Using the adjusted year's expenses under present rates as a base, give detail necessary for clarification of all expense adjustments. Give clarifying detail for any such adjustments that occur due to changes in accounting procedure, such as charging a particular expense to a different account than was used previously. Explain any extraordinary declines in expense due to such change of account use.

Response:

For adjustments to operating expenses, please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D, and the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 4, and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-37

Request:

Indicate the expenses that are recorded in the test year, which are due to the placement in operating service of major plant additions or the removal of major plant from operating service, and estimate the expense that will be incurred on a full-year's operation.

Response:

For a presentation of the major plant additions, cost of removal and plant retirements, refer to Schedules C-2 and C-3 in the UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected). For a presentation of depreciation expense, please refer to Schedule D-21.

Prepared by or under the supervision of: Amy M. Keller

III-A-38

Request:

Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures.

Response:

New Accounting Standard Adopted in Fiscal 2025

Segment Reporting. In November 2023, the FASB issued ASU 2023-07, “Improvements to Reportable Segment Disclosures (Topic 280)” which requires enhanced disclosure of (1) significant segment expenses that are regularly provided to the CODM and included within each reported measure of segment profit or loss, (2) the amount and description of the composition of other segment items which reconcile to segment profit or loss, and (3) the title and position of the entity’s CODM and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and allocating resources. The amendments also expand the interim segment disclosure requirements. In the fourth quarter of Fiscal 2025, the Company adopted the new guidance on a retrospective basis. The adoption of the new guidance did not have a material impact on our consolidated financial statements. See Note 22 for enhanced disclosures.

Accounting Standards Not Yet Adopted

Targeted Improvements to the Accounting for Internal-Use Software. In September 2025, the FASB issued ASU 2025-06, “Targeted Improvements to the Accounting for Internal-Use Software (Subtopic 350-40)” which, among other things, removes the prescriptive project stage requirements and allows entities to capitalize internal-use software costs when management authorizes and commits funding to the project and it is probable the software will be completed and used as intended. This new guidance is effective for the Company for annual and interim periods beginning October 1, 2028 (Fiscal 2029). Early adoption is permitted. The amendments in this ASU may be adopted using the prospective, modified, or retrospective methods. The Company is in the process of assessing the impact on its financial statements and determining the transition method and the period in which the new guidance will be adopted.

III-A-38 (Continued)

Measurement of Credit Losses for Accounts Receivable and Contract Assets. In July 2025, the FASB issued ASU 2025-05, "Measurement of Credit Losses for Accounts Receivable and Contract Assets (Topic 326)" which provides a practical expedient that allows entities to assume that current conditions as of the balance sheet date do not change for the remaining life of the asset when estimating expected credit losses for current accounts receivable and current contract assets. This new guidance is effective for the Company for annual and interim periods beginning October 1, 2026 (Fiscal 2027). Early adoption is permitted. The amendments in this ASU should be adopted using the prospective method. The Company is in the process of assessing the impact on its financial statements and the period in which the new guidance will be adopted.

Disaggregation of Income Statement Expenses. In November 2024, the FASB issued ASU 2024-03, "Disaggregation of Income Statement Expenses (Subtopic 220-40)" which requires enhanced disclosure of income statement expense categories to improve transparency and provide financial statement users with more detailed information about the nature, amount and timing of expenses impacting financial performance. This new guidance is effective for the Company for annual periods beginning October 1, 2027 (Fiscal 2028) and interim periods beginning October 1, 2028 (Fiscal 2029). Early adoption is permitted. The amendments in this ASU may be adopted using the prospective or retrospective methods. The Company is in the process of assessing the impact on its financial statements and determining the transition method and the period in which the new guidance will be adopted.

Improvements to Income Tax Disclosures. In December 2023, the FASB issued ASU 2023-09, "Improvements to Income Tax Disclosures (Topic 740)" which requires entities to disclose, among other items, disaggregated information about a reporting entity's effective tax rate reconciliation and income taxes paid. This new guidance is effective for the Company for annual periods beginning October 1, 2025 (Fiscal 2026). Early adoption is permitted. The amendments in this ASU may be adopted using the prospective or retrospective methods. This Company will adopt the new guidance effective for the year ending September 30, 2026 and provide the additional disclosures as required by the new guidance.

Prepared by or under the supervision of: Amy M. Keller

III-A-39

Request:

Identify the specific witness for all statements and schedules of revenues, expenses, taxes, property, valuation, etc.

Response:

Please see the Direct Testimony of Hans G. Bell, UGI Gas Statement No. 1, for a complete list of witnesses and areas of responsibility. The primary witness for each statement and schedule is identified on the specific document.

Prepared by or under the supervision of: Hans G. Bell

III-A-40

Request:

Adjustments which are estimated shall be fully supported by basic information reasonably necessary.

Response:

Adjustments are fully supported in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Sections C and D, as well as the Direct Testimony of UGI Gas Statement Nos. 1 through 12.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-41

Request:

Submit a statement explaining the derivation of the amounts used for projecting future test year level of operations and submit appropriate schedules supporting the projected test year level of operations.

Response:

The schedules shown in UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D, reflect this information and are the supporting detail for the Fully Projected Future Test Year for the period ending September 30, 2027. Please see the Direct Testimony of Hans G. Bell, UGI Gas Statement No. 1, the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 4, the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5, the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 7, and the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-42

Request:

If a company has separate operating divisions, an income statement must be shown for each division, plus an income statement for company as a whole.

Response:

Please see Attachment III-A-42.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Statements of Income by Division
For the Fiscal Year Ended September 30, 2025
(thousands of dollars)

	UGI Utilities, Inc. Gas	UGI Utilities, Inc. Electric	UGI Utilities, Inc. Total
Revenues			
Electric Utility Revenues	$ -	$ 146,117	$ 146,117
Gas Utility Revenues	1,136,989	-	1,136,989
Other Operating Revenues	174,026	10,736	184,762
Total Operating Revenue	1,311,015	156,853	$ 1,467,868
Expenses			
Operating Expense	55,839	14,547	70,386
Maintenance Expense	35,902	10,085	45,987
Customer Accounts Operations Expense	44,076	5,970	50,045
Customer Service, Information and Sales Expense	3,546	137	3,683
Admin and General Operation Expense	98,441	11,081	109,522
Depreciation and Amortization Expense	142,917	12,338	155,255
Other taxes	13,228	9,613	22,841
Storage, Transportation and Other	573,097	76,907	650,004
Interest Income/Interest Expense	(1,924)	(520)	(2,444)
Miscellaneous Income/Expense	2,566	116	2,683
Long Term Debt Interest	83,930	3,558	87,487
Total Expenses before Taxes	1,051,618	143,831	1,195,449
Income Before Taxes	259,398	13,022	272,419
Tax Expense	55,657	3,332	58,989
Net Income	$ 203,741	$ 9,690	$ 213,430

*UGI Utilities, Inc. Electric includes both Transmission and Distribution.

III-A-43

Request:

If a company's business extends into different states or jurisdictions, then statements must be shown listing Pennsylvania jurisdictional data, other state data and federal data separately and jointly (Balance sheets and operating accounts).

Response:

Please see Attachment III-A-43.1 and Attachment III-A-43.2.

Additionally, the Carverton Road gate station connects the Auburn II line to the Transco interstate pipeline. In late December 2013, a FERC 63 certificate was issued to UGI PNG.

Amounts for the year ended September 30, 2025 are as follows:

Account No.		
146404	UGI ENERGY SERVICES A/R - CARVERTON ROAD	$ 86,324
489026	OTHER REVENUE - CARVERTON ROAD (FERC ORDER 63)	$1,035,888

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
BALANCE SHEET BY STATE JURISDICTION AT
SEPTEMBER 30, 2025
(thousands of dollars)

	Total Company	Pennsylvania Jurisdiction	Maryland Jurisdiction
Utility Plant	$ 4,557,025	$ 4,554,205	$ 2,820
Other Investments	$ 1,693	1,693	$ -
Cash and Cash Equivalents	$ 14,498	14,498	$ -
Accounts Receivable	$ 113,612	113,573	$ 39
Other Receivables	$ 20,336	20,324	$ 12
Other Assets	$ 629,059	630,965	$ (1,906)
Total Assets	$ 5,336,223	$ 5,335,258	$ 965
Current and Accrued Liabilities	$ 495,009	494,845	$ 164
Other Non-current Liabilities	$ 73,621	73,621	$ -
Long-term Debt	$ 1,690,869	1,690,869	$ -
Other Deferred Liabilities	$ 1,118,244	1,118,244	$ -
Total Liabilities	$ 3,377,743	$ 3,377,579	$ 164
Equity	$ 1,958,480	1,957,679	$ 801
Total Liabilities and Equity	$ 5,336,223	$ 5,335,258	$ 965

UGI Utilities, Inc. - Gas Division
Statement of Operations - by Division
For Year Ended September 30, 2025
(thousands of dollars)

	Total Company	Pennsylvania Jurisdiction	Maryland Jurisdiction
Revenues			
Gas Utility Revenues	$ 1,136,989	$ 1,136,253	$ 736
Other Operating Revenues	174,026	173,906	121
Total Operating Revenue	1,311,015	1,310,159	856
Expenses:			
Operating Expense	55,839	55,801	39
Maintenance Expense	35,902	35,877	25
Customer Accounts Operations Expense	44,076	44,045	31
Customer Service and Information Operations Expense	3,546	3,544	2
Admin and General Operation Expense	98,441	98,373	68
Depreciation and Amortization Expense	142,917	142,818	99
Other taxes	13,228	13,219	9
Storage, Transportation and Other	573,097	572,677	420
Interest Income	(1,924)	(1,923)	(1)
Miscellaneous Income/Expense	2,566	2,564	2
Long Term Debt Interest	83,930	83,872	58
Total Expenses before Taxes	1,051,618	1,050,866	752
Income Before Taxes	259,398	259,293	104
Tax Expense	55,657	55,618	39
Net Income	$ 203,741	$ 203,675	$ 66

III-A-44

Request:

Ratios, percentages, allocations and averages used in adjustments must be fully supported and identified as to source.

Response:

Ratios, percentages, allocations and averages, where utilized, are detailed in the supporting adjustments to revenue and expenses set forth in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D. Please also refer to the Direct Testimony of UGI Gas Statement Nos. 1 through 12.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-45

Request:

Provide an explanation of any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate case.

Response:

There have been no changes to the allocation methodology.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-46

Request:

Supply a copy of internal and independent audit reports of the test year and prior calendar year, noting any exceptions and recommendations and disposition thereof.

Response:

Please see Attachment III-A-46 for the list of audit reports for the historic test year and prior year. The information contained in these reports is deemed confidential. Any party to the proceeding requiring access to these reports will be afforded the opportunity upon request, subject to the provisions of a Confidentiality Agreement to be entered into between such party and the Company pursuant to a Protective Order.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Listing of Audit Reports

Entity	Audit Report Name	Auditor	Audit Year	Date Issued
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities, Inc.	KPMG	FY25	12/18/25
UGI Corporate	Endpoint Detection & Response, Global IT Audit	Internal Audit	FY25	02/03/25
UGI Corporate	Shadow IT System Ownership, Global IT Audit	Internal Audit	FY25	01/25/25
UGI Corporate	Hedging Compliance Audit	Internal Audit	FY24	10/28/24
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities, Inc.	Ernst & Young, LLP	FY24	12/18/24

III-A-47

Request:

Submit a schedule showing rate of return on facilities allocated to serve wholesale customers.

Response:

There are no facilities allocated for the provision to serve wholesale customers.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-48

Request:

Provide a copy of the latest capital stock tax report and the latest capital stock tax settlement.

Response:

Not applicable. The PA Capital Stock tax was eliminated for tax years beginning January 1, 2016. Last filed PA Capital Stock tax return was for tax year ending September 30, 2016.

Prepared by or under the supervision of: Darin T. Espigh

III-A-49

Request:

Submit details of calculations for Taxes, Other than Income where a company is assessed taxes for doing business in another state, or on its property located in another state.

Response:

Details of Taxes, Other Than Income where UGI Gas is assessed taxes for doing business in another state, or on its property in another state for the period ended September 30, 2025, are listed below:

1.	Maryland (Property, Franchise and PSC Tax):	$33,230
2.	Mississippi (Property Tax):	$ 4,461
	Total:	$37,691

Prepared by or under the supervision of: Darin T. Espigh

III-A-50

Request:

Provide a schedule of federal and Pennsylvania taxes, other than income taxes, calculated on the basis of test year per books, pro forma at present rates, and pro forma at proposed rates, to include the following categories:

a. social security
b. unemployment
c. capital stock
d. public utility realty
e. P.U.C. assessment
f. other property
g. any other appropriate categories

Response:

Refer to UGI Gas Exhibit A, Schedules D-31 and D-32 for the Historic, Future, and Fully Projected Future test years.

Prepared by or under the supervision of: Darin T. Espigh

III-A-51

Request:

Submit a schedule showing for the last five years the income tax refunds, plus interest (net of taxes), received from the federal government due to prior years' claims.

Response:

None.

Prepared by or under the supervision of: Darin T. Espigh

III-A-52

Request:

Provide detailed computations showing the deferred income taxes derived by using accelerated tax depreciation applicable to post-1969 utility property increases productive capacity, and ADR rates on property. (Separate between state and federal; also, rate used)

a. State whether tax depreciation is based on all rate base items claimed as of the end of the test year, and whether it is the annual tax depreciation at the end of the test year.

b. Reconcile any difference between the deferred tax balance, as shown as a reduction to measures of value (rate base), and the deferred tax balance as shown on the balance sheet.

Response:

See Schedules D-33 and D-34 in Exhibit A (Historic), Exhibit A (Future), and Exhibit A (Fully Projected) for the computation of federal and state deferred income taxes.

a. Tax depreciation subject to normalization is based on depreciable property as of the end of the test year. Further, tax depreciation is annualized as of the end of the test year period.

b. The accumulated deferred tax balance, as shown as a reduction to measures of value, represents the annualized balance based on the plant in service included in the measures of value, and then pro-rated according to the normalization rules under Treasury Regulation 1.167(l)-1(h)(6)(ii). The balance sheet represents the budgeted balance.

Prepared by or under the supervision of: Darin T. Espigh

III-A-53

Request:

Submit a schedule showing a breakdown of the deferred income taxes by state and federal per books, pro-forma existing rates, and under proposed rates.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33.

Prepared by or under the supervision of: Darin T. Espigh

III-A-54

Request:

Submit a schedule showing a breakdown of accumulated investment tax credits (3 percent, 4 percent, 7 percent, 10 percent and 11 percent), together with details of methods used to write-off the unamortized balances.

Response:

As of fiscal year ended September 30, 2025, the amount of UGI Gas' accumulated 3% investment tax credit was $402,468.

This investment credit is amortized on a straight-line basis. The annual amortization of the credit is $318,420.

Prepared by or under the supervision of: Darin T. Espigh

III-A-55

Request:

Submit a schedule showing the adjustments for taxable net income per books (including below-the-line items) and pro-forma under existing rates, together with an explanation of any difference between the adjustments. Indicate charitable donations and contributions in the tax calculation for rate making purposes.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules A-1, D-1, D-33 and D-34. For ratemaking purposes, charitable donations and contributions are not being claimed and are excluded from test year data.

Prepared by or under the supervision of: Darin T. Espigh

III-A-56

Request:

Submit detailed calculations supporting taxable income before state and federal income taxes where the income tax is subject to allocation due to operations in another state, or due to operation of other taxable utility or non-utility business, or by operating divisions or areas.

Response:

Please see Attachment III-A-56.

UGI Gas has established nexus for income tax purposes in other states due to having storage inventory in those states. Because of having nexus with those states, it files tax returns with income allocated to those states. Income is allocated according to the apportionment rules for each state. Attachment III-A-56 reflects that allocation of taxable income.

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Gas Division
Allocation of Income to Other States, Other Operating Divisions, & Non-Utility Operations
Historic Test Year - 9/30/25
In Thousands (000)

	(1) As Filed	(2) PA	(3) Non-PA
Revenue	1,149,615	1,148,705	594
Operating Expenses	(810,753)	(810,111)	(419)
Depr & Amort	(142,830)	(142,717)	(74)
Taxes Other Than Income	(12,560)	(12,550)	(6)
Total Operating Expenses	(966,143)	(965,378)	(499)
Interest Expense	(81,919)	(81,854)	(42)
Book/Tax Depr Adj	(120,850)	(120,754)	(62)
Taxable Income	(19,296)	(19,281)	(10)

III-A-57

Request:

Submit detailed calculations showing the derivation of deferred income taxes for amortization of repair allowance if such policy is followed.

[Note: Submit additional schedules if the company has more than one accounting area.]

Response:

Please see Exhibit A, Schedule D-33 (Historic); Exhibit A, Schedule D-33 (Future); and Exhibit A, Schedule D-33 (Fully Projected) for the repairs deferred income tax expense for each of the respective years.

Please see Exhibit A, Schedule C-6 (Historic); Exhibit A, Schedule C-6 (Future); and Exhibit A Schedule C-6 (Fully Projected) for the repairs accumulated deferred income tax balance for each of the respective years.

Also, see the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9, for an explanation of the Company's regulatory treatment of the repairs tax allowance.

Prepared by or under the supervision of: Darin T. Espigh

III-A-58

Request:

Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits and reserves by accounting areas.

Response:

See UGI Gas Exhibit A, Schedule C-6 (Historic) for deferred taxes relative to plant in service.

The net value of deferred taxes on items other than plant in service at fiscal year ended 9/30/2025 is a deferred tax liability of $52,127,436.

Prepared by or under the supervision of: Darin T. Espigh

III-A-59

Request:

Provide details of the Federal Surtax Credit allocated to the Pennsylvania jurisdictional area, if applicable.

Response:

Not applicable.

Prepared by or under the supervision of: Darin T. Espigh

III-A-60

Request:

Explain the reason for the use of cost of removal of any retired plant figures in the income tax calculations.

Response:

For income tax purposes, the cost of removal is deductible in the year incurred. For book purposes, the cost is amortized over 60 months.

Prepared by or under the supervision of: Darin T. Espigh

III-A-61

Request:

Submit the corresponding data applicable to Pennsylvania Corporate Income Tax deferment.

a. Show the amounts of straight line tax depreciation and accelerated tax depreciation, the difference between which gave rise to the normalizing tax charged back to the test year operating statement.

b. Show normalization for both Federal and State Income Taxes.

c. Show tax rates used to calculate tax deferment amount.

Response:

a.& b. Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), UGI Gas Exhibit A (Fully Projected), Schedules D-33 and D-34, which provide details of the deferred income taxes from normalized depreciation separately for Federal and State.

c. For the FPFTY, the U.S. gross federal income tax rate is 21%, but net of the federal benefit for state taxes it becomes 19.43%. The state tax rate is 7.49%.

Prepared by or under the supervision of: Darin T. Espigh

III-A-62

Request:

Provide the accelerated tax depreciation and the book depreciation used to calculate test year deferrals in amounts segregated as follows:

For:

a. Property installed prior to 1970

b. Property installed subsequent to 1969 (indicate increasing capacity additions and nonincreasing capacity additions).

Response:

a. There is no property installed prior to 1970 for tax purposes.

b. Tax depreciation related to accelerated cost recovery system (ACRS) and modified accelerated cost recovery system (MACRS) is calculated on the full taxable basis and income taxes are normalized on the difference between ACRS/MACRS depreciation and book depreciation. For property installed subsequent to 1969, see Section D, Schedule D-34 within UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected).

Prepared by or under the supervision of: Darin T. Espigh

III-A-63

Request:

State whether all tax savings due to accelerated depreciation on property installed prior to 1970 have been passed through to income. (If not, explain).

Response:

All tax savings have been passed through and UGI Gas has no remaining accelerated depreciation on property installed prior to 1970.

Prepared by or under the supervision of: Darin T. Espigh

III-A-64

Request:

Show any income tax loss/gain carryovers from previous years that may effect test year income taxes or future year income taxes. Show loss/gain carryovers by years of origin and amounts remaining by years at the end of the test year.

Response:

Not applicable.

Prepared by or under the supervision of: Darin T. Espigh

III-A-65

Request:

State whether the company eliminates any tax savings by the payment of actual interest on construction work in progress not in rate base claim.

If response is affirmative:

a. Set forth amount of construction claimed in this tax savings reduction. Explain the basis for this amount.

b. Explain the manner in which the debt portion of this construction is determined for purposes of the deferral calculations.

c. State the interest rate used to calculate interest on this construction debt portion, and the manner in which it is derived.

d. Provide details of calculation to determine tax saving reduction. State whether state taxes are increased to reflect the construction interest elimination.

Response:

No. Interest deduction for rate making purposes is synchronized with the interest component of the capital structure.

Prepared by or under the supervision of: Darin T. Espigh

III-A-66

Request:

Provide a detailed analysis of Taxes Accrued per books as of the test year date. Also supply the basis for the accrual and the amount of taxes accrued monthly.

Response:

Please see Attachments III-A-66.1 (Historic), III-A-66.2 (Future), and III-A-66.3 (Fully Projected).

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Historic Test Year
Twelve Months Ended September 30, 2025
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Unemployment Tax	121	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	1,676	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	31	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	2,136	Tax for OASDI is based on the first $176,100 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	2,259	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 8.49% for the fiscal year 2025.	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	(8,594)	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income. Note, the amount reflected is negative due to cash payments exceeding accrued tax expense.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ (2,371)		

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Future Test Year
Twelve Months Ended September 30, 2026
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Unemployment Tax	0	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	0	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	0	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	0	Tax for OASDI is based on the first $184,500 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	0	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 7.99% for the fiscal year 2026.	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	0	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ -		

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Fully Projected Future Test Year
Twelve Months Ended September 30, 2027
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Unemployment Tax	0	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	0	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	0	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	0	Tax for OASDI is based on the first $184,500 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	0	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 7.49% for the fiscal year 2027.	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	0	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ -		

III-A-67

Request:

For the test year as recorded on test year operating statement:

a. Supply the amount of federal income taxes actually paid.

b. Supply the amount of the federal income tax normalizing charge to tax expense due to excess of accelerated tax depreciation over book depreciation.

c. Supply the normalizing tax charge to federal income taxes for the 10% Job Development Credit during test year.

d. Provide the amount of the credit of federal income taxes due to the amortization or normalizing yearly debit to the reserve for the 10% Job Development Credit.

e. Provide the amount of the credit to federal income taxes for the normalizing of any 3% Investment Tax Credit Reserve that may remain on the utility books.

Response:

a & b. Refer to UGI Gas Exhibit A, Schedule D-33 for the Historic, Future, and Fully Projected test years.

c & d. None.

e. $318,420.

Prepared by or under the supervision of: Darin T. Espigh

III-A-68

Request:

Provide the debit and credit in the test year to the Deferred Taxes due to Accelerated Depreciation for federal income tax, and provide the debit and credit for the Job Development Credits (whatever account) for test year.

Response:

The debit and credit in the test year to the Deferred Taxes due to Accelerated Depreciation for federal income tax is as follows:

A/C #	Account Description	Debit	Credit
00410XXX	Deferred Tax Expense	$XXX,XXX	
00282XXX	Accumulated Deferred Taxes		$XXX,XXX

UGI Gas has no Job Development Credits.

Prepared by or under the supervision of: Darin T. Espigh

III-A-69

Request:

Reconcile all data given in answers to questions on income taxes charged on the test year operating statement with regard to income taxes paid, income taxes charged because of normalization and credits due to yearly write-offs of past years' income tax deferrals, and from normalization of investment tax and development credits. (Both state and federal income taxes.)

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Section D, Schedules D-33 and D-34. Also, refer to the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9, where the subject matter of this filing requirement is discussed in detail.

Prepared by or under the supervision of: Darin T. Espigh

III-A-70

Request:

With respect to determination of income taxes, federal and state:

a. Show income tax results of the annualizing and normalizing adjustments to the test year record before any rate increase.

b. Show income taxes for the annualized and normalized test year.

c. Show income tax effect of the rate increase requested.

d. Show income taxes for the normalized and annualized test year after application of the full rate increase.

[It is imperative that continuity exists between the income tax calculations as recorded for the test year and the final income tax calculation under proposed rates. If the company has more than one accounting area, then additional separate worksheets must be provided in addition to those for total company.]

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Section D, Schedules D-33 and D-34.

Prepared by or under the supervision of: Darin T. Espigh

III-A-71

Request:

In adjusting the test year to an annualized year under present rates, explain any changes that may be due to book or tax depreciation change and to debits and credits to income tax expense due to accelerated depreciation, deferred taxes, job development credits, tax refunds or other items.

(The above refers only the adjustments going from recorded test year to annualized test year.)

Response:

Adjustments relative to the subject matter were made to recorded data to annualize the years' data and are based on property balances at the end of the test year to reflect a full year's expense of deferral. Please see the Direct Testimony of Darin T. Espigh, UGI Gas Statement No. 9.

Prepared by or under the supervision of: Darin T. Espigh

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III-E-1

Request:

If Unrecovered Fuel Cost policy is implemented, provide the following:

a. State manner in which amount of Unrecovered Fuel Cost on balance sheet at the end of the test year was determined, and the month in test year in which such fuel expense was actually incurred. Provide amount of adjustment made on the rate case operating account for test year-end unrecovered fuel cost. (If different than balance sheet amount, explain.)

b. Provide amount of Unrecovered Fuel Cost that appeared on the balance sheet at the opening date of the test year, and the manner in which it was determined. State whether this amount is in the test year operating account.

Response:

a. For information regarding the unrecovered purchased fuel cost, please refer to the 1307(f) filing.

b. See Attachment III-E-1.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Unrecovered Fuel Costs and Revenues
For the periods ending September 30, 2024 and 2025
U.S. Dollars in Thousands

Month	Year	Fuel Costs	Revenues	Under (Over) Collection
October	2023	11,124	11,323	(199)
November	2023	38,389	25,773	12,616
December	2023	46,254	46,804	(550)
January	2024	62,724	53,064	9,660
February	2024	43,194	49,596	(6,402)
March	2024	37,408	38,328	(919)
April	2024	14,145	29,056	(14,911)
May	2024	10,886	12,492	(1,605)
June	2024	10,190	6,369	3,821
July	2024	12,793	5,365	7,428
August	2024	10,723	5,081	5,641
September	2024	9,382	5,255	4,126
October	2024	14,142	8,521	5,621
November	2024	34,157	15,386	18,772
December	2024	55,511	43,107	12,403
January	2025	78,711	70,853	7,858
February	2025	59,285	65,097	(5,812)
March	2025	45,989	57,169	(11,180)
April	2025	24,480	34,320	(9,840)
May	2025	15,770	17,501	(1,732)
June	2025	13,672	10,836	2,837
July	2025	8,924	6,701	2,222
August	2025	14,162	5,855	8,307
September	2025	11,750	6,780	4,970

Beginning Balance as of 9/30/2024		(2,343)
Purchased Fuel Cost Adjustment		53,133
Unrecovered Purchased Fuel Cost as of 9/30/2025	$	50,790

* For further information regarding the unrecovered purchased fuel cost, please refer to the 1307(f) filing.

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III-E-2

Request:

Provide details of items and amounts comprising the accounting entries for Deferred Fuel Cost at the beginning and end of the test year.

Response:

Refer to Attachment III-E-1 for an analysis of entries made to the Deferred Fuel Cost Account during the Fully Projected Future Test Year.

Prepared by or under the supervision of: Tracy A. Hazenstab

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III-E-3

Request:

Submit a schedule showing a reconciliation of test year MCF sales and line losses. List all amounts of gas purchased, manufactured and transported.

Response:

The data is provided below for the Historic Year:

Throughput -	321,987,283 Mcf
Company Use Gas -	404,613 Mcf
Line Loss -	1,699,226 Mcf
Total Sendout -	324,091,122 Mcf

Prepared by or under the supervision of: Tracy A. Hazenstab

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III-E-4

Request:

Provide detailed calculations substantiating the adjustment to revenues for annualization of changes in number of customers and annualization of changes in volume sold for all customers for the test year.

a. Break down changes in number of customers by rate schedules.

b. If an annualization adjustment for changes in customers and changes in volume sold is not submitted, please explain.

Response:

a. Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10.

b. Not applicable.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-5

Request:

Submit a schedule showing the sources of gas supply associated with annualized MCF sales.

Response:

Please see the response to III-E-30.

Prepared by or under the supervision of: Tracy A. Hazenstab

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III-E-6

Request:

Supply, by classification, Operating Revenues--Miscellaneous for test year.

Response:

Please see Attachment III-E-6.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Operating Revenues - Miscellaneous
For the Years Ended September 30, 2025, 2026, and 2027
($ in Thousands)

Account No.		Actual 12 Months 9/30/2025	Budgeted 12 Months 9/30/2026	Budgeted 12 Months 9/30/2027
487	Forfeited Discounts	$ 5,460	$ 6,261	$ 6,337
488 & 489.3	Miscellaneous Service Revenues	$ 3,694	$ 3,178	$ 3,178
493	Rent from Gas Property	$ 2,106	$ 2,292	$ 2,292
495	Other Gas Revenues	$ 980	$ 2,450	$ 2,324
	Total	$ 12,240	$ 14,181	$ 14,131

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III-E-7

Request:

Provide details of respondent's attempts to recover uncollectible and delinquent accounts.

Response:

The Company performs collection activities on all active accounts in accordance with applicable Commission requirements. When those collection activities are exhausted, UGI Gas refers bad debt placements to a collection agency for continuing collection action. When the service is closed, the customer receives a closing bill. Placements are sent to the collection agency within ninety (90) days after the service is closed. The day after the final bill is due, a Final Bill Reminder is mailed. The reminder states that their balance must be paid to avoid being turned over to a collection agency. Forty-five (45) days later, if the balance has not been paid, the account is sent to collections.

Prepared by or under the supervision of: Vivian K. Ressler

III-E-8

Request:

Describe how the net billing and gross billing is determined. For example, if the net billing is based on the rate blocks plus FCA and STA, and the gross billing is determined by a percentage increase (1, 3 or 5 percent), then state whether the percentage increase is being applied to all three items of revenue--rate blocks plus FCA and STA.

Response:

A. The total net bill is the sum of:

1. Tariff Amount – calculated as the volume of usage priced through the rate schedule tables.

2. Currently effective surcharges.

3. Sales Tax – calculated as the product of the current sales tax percentage (6%) and the sum of the above. Sales tax is not applied to residential customers when the purchase of natural gas is solely for the purchaser's own residential use and non-residential customers are exempt from sales tax if the purchaser is entitled to claim an exemption under Chapter 61 of the Pa. Code § 32.25 subsection (d). If a tax exemption certificate is on file for these non-residential customers, the tax base is adjusted in accordance with the exemption certificate.

B. The gross bill is the sum of:

1. Total net bill as described above.

2. Late payment charges on any unpaid previous balance, if any, as of the billing date.

3. Late payment charge for payment made after the due date (see III-E-9 for details on late payment charges applied).

III-E-8 (Continued)

C. The percentage increase (late payment charge) is applied to the base tariff rate and the State Tax Adjustment Surcharge. The late payment charge is not applied to Sales Tax or to previously applied late payment charges.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-9

Request:

Describe the procedures involved in determining whether forfeited discounts or penalties are applied to customer billing.

Response:

Please refer to UGI Gas Exhibit F, Rules 8.7 and 8.8 of the current Tariff for UGI Utilities, Inc. – Gas Division.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-10

Request:

Provide annualization of revenues as a result of rate changes occuring during the test year, at the level of operations as of end of the test year.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10, for detail on the annualization of revenues.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-11

Request:

Provide a detailed billing analysis supporting present and proposed rates by customer classification and/or tariff rate schedule.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-12

Request:

Provide a schedule showing residential and commercial heating sales by unit (MCF) per month and degree days for the test year and three preceding twelve month periods.

Response:

Please see Attachment III-E-12.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential and Commercial Heating Sales (Mcf's)

	October	November	December	January	February	March	April	May	June	July	August	September	Total
Degree Days													
2023-2024	289	678	756	985	815	603	341	95	4	-	12	35	4,613
2024-2025	278	562	957	1,216	941	604	359	160	20	-	24	17	5,138
2025-2026	309	647	895	1,069	881	749	410	155	27	-	8	68	5,218
2026-2027	309	647	895	1,069	881	749	410	155	27	-	8	68	5,218
Residential Heating Sales (Mcf's) Rate R & RT													
2023-2024	2,223,166	5,551,868	7,014,035	9,076,624	7,300,074	5,527,700	3,242,163	1,379,484	920,500	793,447	821,120	652,617	44,502,798
2024-2025	2,161,554	4,514,917	8,754,953	11,349,169	8,910,640	5,411,692	3,295,759	1,456,913	818,877	743,423	847,283	700,484	48,965,664
2025-2026	2,295,795	5,254,894	8,186,370	9,871,386	8,320,917	7,015,796	3,545,376	1,782,104	1,149,141	788,666	826,498	883,313	49,920,255
2026-2027	2,313,740	5,293,851	8,253,045	9,954,629	8,388,409	7,064,719	3,572,251	1,795,020	1,157,329	795,142	833,341	889,995	50,311,471
Commercial Heating Sales (Mcf's) Rate N, NT & DS													
2023-2024	1,694,572	4,069,138	4,776,916	6,352,022	5,118,145	3,862,363	2,382,490	1,199,817	922,468	928,169	928,070	824,228	33,058,398
2024-2025	1,616,251	3,167,518	5,954,502	7,767,337	6,213,109	3,863,373	2,554,296	1,357,485	917,585	854,209	898,293	881,750	36,045,708
2025-2026	1,579,249	3,178,249	5,392,321	6,843,176	5,724,269	4,372,745	2,456,096	1,289,548	903,421	779,469	807,346	846,064	34,171,954
2026-2027	1,586,420	3,190,017	5,409,964	6,864,555	5,742,397	4,387,650	2,464,344	1,294,139	906,594	782,335	810,512	849,317	34,288,244

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III-E-13

Request:

Provide a schedule of present and proposed tariff rates showing dollar change and percent of change by block. Also, provide an explanation of any change in block structure and the reasons therefor.

Response:

Please see UGI Gas Exhibit E – Proof of Revenue and the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10.

Prepared by or under the supervision of: Sherry A. Epler

III-E-14

Request:

Provide the following statements and schedules. The schedules and statements for the test year portion should be reconciled with the summary operating statement.

a. An operating revenues summary for the test year and the year preceding the test year showing the following (Gas MCF):

(i) For each major classification of customers

(a) MCF sales
(b) Dollar Revenues
(c) Forfeited Discounts (Total if not available by classification)
(d) Other and Miscellaneous revenues that are to be taken into the utility operating account along with their related costs and expenses.

(ii) A detailed explanation of all annualizing and normalizing adjustments showing method utilized and amounts and rates used in calculation to arrive at adjustment.

(iii) Segregate, from recorded revenues from the test year, the amount of revenues that are contained therein, by appropriate revenue categories, from:

(a) Fuel Adjustment Surcharge
(b) State Tax Surcharge
(c) Any other surcharge being used to collect revenues.
(d) Provide explanations if any of the surcharges are not applicable to respondent’s operations.

[The schedule should also show number of customers and unit of sales (Mcf), and should provide number of customers by service classification at beginning and end of test year.]

b. Provide details of sales for resale, based on periods five years before and projections for five years after the test year, and for the test year. List customers,

III-E-14 (Continued)

Mcf sold, revenues received, source of Mcf sold (storage gas, pipeline gas, manufactured gas, natural or synthetic), contracted or spot sales, whether sales are to affiliated companies, and any other pertinent information.

Response:

a. (i)(a) Please see Attachment III-E-19.

(i)(b)-(d) Please see UGI Gas Exhibit A, Schedule D-5 (Historic), UGI Gas Exhibit A, Schedule D-5 (Future), and UGI Gas Exhibit A, Schedule D-5 (Fully Projected).

(ii) Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10.

(iii) Please see UGI Gas Exhibit E, Proof of Revenue.

b. None.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-15

Request:

State manner in which revenues are being presented for ratemaking purposes:

a. Accrued Revenues
b. Billed Revenues
c. Cash Revenues

Provide details of the method followed.

Response:

Fully Projected Test Year revenues at present and proposed rates are based upon a calculation applying present rates to projected volumes and number of customers and proposed rates to projected volumes and number of customers.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-16

Request:

If revenue accruing entries are made on the books at end of each fiscal period, give entries made accordingly at the end of the test year and at the beginning of the year. State whether they are reversed for ratemaking purposes.

Response:

The amount of unbilled revenue accrued at September 30, 2025 and September 30, 2024 for UGI Gas was $20,334,010; and $20,125,330, respectively. The Company annualizes revenue for ratemaking purposes eliminating the impacts of unbilled revenues.

Prepared by or under the supervision of: Amy M. Keller

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III-E-17

Request:

State whether any adjustments have been made to expenses in order to present such expenses on a basis comparable to the manner in which revenues are presented in this proceeding (i.e.--accrued, billed or cash).

Response:

No such adjustments have been made to expenses. Expenses are presented on a basis comparable to the manner in which revenues are presented.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-18

Request:

If the utility has a Fuel Adjustment Clause:

a. State the base fuel cost per MCF chargeable against basic customers' rates during the test year. If there was any change in this basic fuel charge during the test year, give details and explanation thereof.

b. State the amount in which the fuel adjustment clause cost per MCF exceeds the fuel cost per MCF charged in base rates at the end of the test year.

c. If fuel cost deferment is used at the end of the test year, give

   (i) The amount of deferred fuel cost contained in the operating statement that was deferred from the 12-month operating period immediately preceding the test year.

   (ii) The amount of deferred fuel cost that was removed from the test period and deferred to the period immediately following the test year.

d. State the amount of Fuel Adjustment Clause revenues credited to the test year operating account.

e. State the amount of fuel cost charged to the operating expense account in the test year which is the basis of Fuel Adjustment Clause billings to customers in that year. Provide summary details of this charge.

f. From the recorded test year operating account, remove the Fuel Adjustment Clause Revenues. Also remove from the test year recorded operating account the excess of fuel cost over base rate fuel charges, which is the basis for the Fuel Adjustment charges. Explain any difference between FAC Revenues and excess fuel costs. [The above is intended to limit the operating account to existing customers' base rate revenues and expense deductions relative thereto].

III-E-18 (Continued)

Response:

The Company does not have a Fuel Adjustment Clause. The Company recovers its purchased gas costs through purchased gas cost rates under Section 1307(f) of the Public Utility Code.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-19

Request:

Provide growth patterns of usage and customer numbers per rate class, using historical and projected data.

Response:

Please see Attachment III-E-19.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Usage and Customer Growth Patterns for Period Ending September 30

Number of Customers September Year End	September 2023	September 2024	September 2025	September 2026	September 2027
Residential	529,873	537,599	539,764	546,897	552,510
Commercial	47,581	47,471	48,083	48,311	48,510
Industrial	661	667	673	625	613
Subtotal-Retail	578,115	585,737	588,520	595,833	601,633
Transportation-Other	105,661	102,854	105,239	104,597	104,599
Total	683,776	688,591	693,759	700,430	706,232

Total Fiscal Year Sales (Mcf's)	September 2023	September 2024	September 2025	September 2026	September 2027
Residential	40,520,719	38,977,291	43,130,950	44,090,812	44,265,497
Commercial	16,042,840	14,384,150	16,391,738	15,311,427	15,390,049
Industrial	881,133	688,784	779,268	449,955	401,675
Subtotal-Retail	57,444,693	54,050,225	60,301,956	59,852,194	60,057,221
Transportation-Other	266,671,688	272,766,224	261,326,796	279,116,251	279,147,010
Total	324,116,381	326,816,449	321,628,752	338,968,445	339,204,231

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III-E-20

Request:

Provide, for test year only, a schedule by tariff rates and by service classifications showing proposed increase and percent of increase.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue and the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10.

Prepared by or under the supervision of: Sherry A. Epler

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III-E-21

Request:

If a gas company is affiliated with another utility segment, such as a water or electric segment, explain the effects, if any, upon allocation factors used in the gas rate filing of current or recent rate increases allowed to the other utility segment (or segments) of the company.

Response:

UGI Utilities, Inc. owns both gas and electric divisions.

UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI Utilities also allocates or assigns costs between UGI Electric and UGI Gas. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are done by a methodology applicable to the cost (e.g., budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by a formula referred to as the Modified Wisconsin Formula ("MWF"). The MWF achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units, which benefit from the respective activities. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

The proposed rates of UGI Gas are not based on any increase granted to any other affiliated utility segment.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-22

Request:

Provide supporting data detailing curtailment adjustments, procedures and policies.

Response:

The Company did not have any curtailment adjustments during the historic test year ending September 30, 2025, and is not claiming any curtailment adjustments in its future test year or fully projected future test year. In addition, the Company follows curtailment procedures and policies as specified in its Gas Tariff on file with the Commission. Please refer to UGI Gas Exhibit F, Section 21, Gas Emergency Planning, of the Company's current Tariff.

Prepared by or under the supervision of: Jill E. Walter

III-E-23

Request:

Submit a schedule showing fuel cost in excess of base compared to fuel cost recovery for the period two months prior to test year and the test year.

Response:

There are no fuel costs in excess of base compared to fuel cost recovery.

All of the Company's fuel costs are recovered through its annual purchased gas cost filing made pursuant to Section 1307(f) of the Public Utility Code.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-24

Request:

Supply a detailed analysis of Purchased Gas for the test year and the twelve month period prior to the test year.

Response:

Please refer to UGI Gas Docket No. R-2025-3054938 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2025-3054938.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-25

Request:

Submit calculations supporting energy cost per MCF and operating ratio used to determine increase in costs other than production to serve additional load.

Response:

The energy cost per Mcf is developed as part of each annual and quarterly 1307(f) filing submitted to the Commission. Please refer to UGI Gas Docket No. R-2025-3054938 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2025-3054938.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-26

Request:

Submit detailed calculations for bulk gas transmission service costs under supply and/or interconnection agreements.

Response:

UGI Gas incurs no bulk gas transmission costs under supply and/or interconnection agreements.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-27

Request:

Submit a schedule for gas producing units retired or scheduled for retirement subsequent to the test year showing station, units, MCF capacity, hours of operation during test year, net output produced and cents/MCF of maintenance and fuel expenses.

Response:

UGI Gas did not have any gas producing units retired or scheduled for retirement subsequent to the test year.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-28

Request:

Provide a statement explaining the details of firm gas purchase (long-term) contracts with affiliated and nonaffiliated utilities, including determination of costs, terms of contract, and other pertinent information.

Response:

Please refer to Section 1-B of UGI Gas's most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing at Docket No. R-2025-3054938, which can be found at https://www.puc.pa.gov/docket/R-2025-3054938.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-29

Request:

Provide intrastate operations percentages by expense categories for two years prior to the test year.

Response:

Please see Attachment III-E-29.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Base Rate Case - Expense Allocation
Sales (Mcf)

	HTY (FY25)	FTY (FY 26)	FPFTY (FY 27)
PA Volume	321,628,752	338,968,445	339,204,231
Maryland Volume	222,957	158,982	158,982
Maryland Allocation	0.069%	0.047%	0.047%
PA Allocation	99.931%	99.953%	99.953%

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-30

Request:

Provide a schedule showing suppliers, MCF purchased, cost (small purchases from independent suppliers may be grouped); emergency purchases, listing same information; curtailments during the year; gas put into and taken out of storage; line loss, and any other gas input or output not in the ordinary course of business.

Response:

Please refer to UGI Gas Docket No. R-2025-3054938 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filings which can be found at URL https://www.puc.pa.gov/docket/R-2025-3054938.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-31

Request:

Provide a schedule showing the determination of the fuel costs included in the base cost of fuel.

Response:

Please refer to UGI Gas Docket No. R-2025-3054938 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2025-3054938.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-32

Request:

Provide a schedule showing the calculation of any deferred fuel costs shown in Account 174. Also, explain the accounting, with supporting detail, for any associated income taxes.

Response:

Please see Attachment III-E-32.

Because the tax treatment for deferred fuel costs differs from the book treatment, deferred taxes are generated on the over or under-collection of deferred fuel costs. Specifically, tax follows a cash basis as it relates to deferred fuel costs. When the Company is in an over-collected position, a deferred tax asset is generated because the Company will recognize it as taxable income and pay taxes currently on the cash it collected from customers, even though this is not recognized as book revenue. Vice versa, when the Company is in an under-collected position, a deferred tax liability is generated because the Company recognizes less taxable income because it did not collect adequate cash to cover its fuel costs, but for book purposes revenue is recognized such that no margin is recognized on the purchase of gas.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Statement of Total Over/Under Collections From the Present
Gas Cost Rate Adjustment Clause - 12 Months Ending September 30, 2025

	Sales Mcf (1)	PGC Revenue (2)	Cost of Fuel (3)	Over / (Under) Collections (4)
October	1,628,796	$ 8,520,626	$ 14,141,881	$ (5,621,256)
November	2,940,852	$ 15,385,826	$ 34,157,331	$ (18,771,506)
December	8,080,926	$ 43,107,456	$ 55,510,820	$ (12,403,364)
January	12,985,358	$ 70,853,137	$ 78,710,753	$ (7,857,616)
February	11,926,128	$ 65,096,899	$ 59,284,974	$ 5,811,925
March	9,840,795	$ 57,169,301	$ 45,988,942	$ 11,180,359
April	5,453,568	$ 34,320,061	$ 24,480,466	$ 9,839,595
May	2,784,674	$ 17,501,312	$ 15,769,807	$ 1,731,505
June	1,721,722	$ 10,835,537	$ 13,672,119	$ (2,836,581)
July	1,064,688	$ 6,701,349	$ 8,923,639	$ (2,222,290)
August	930,299	$ 5,854,726	$ 14,162,004	$ (8,307,278)
September	1,077,228	$ 6,779,710	$ 11,750,020	$ (4,970,310)
	60,435,034	$ 342,125,940	$ 376,552,756	$ (34,426,817)

III-E-33

Request:

Submit a schedule showing maintenance expenses, gross plant and the relation of maintenance expenses thereto as follows:

(i) Gas Production Maintenance Expenses per MCF production, per $1,000 MCF production, and per $1,000 of Gross Production Plant;

(ii) Transmission Maintenance Expenses per MMCF mile and per $1,000 of Gross Transmission Plant;

(iii) Distribution Maintenance Expenses per customer and per $1,000 of Gross Distribution Plant;

(iv) Storage Maintenance Expenses per MMCF of Storage Capacity and $1,000 of Gross Storage Plant. This schedule shall include three years prior to the test year, the test year and one year's projection beyond the test year.

Response:

Please see Attachment III-E-33.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
FOR THE YEARS ENDED SEPTEMBER 30, 2023 -2027

		12 MONTHS ENDED				
		9/30/23	9/30/24	9/30/25	9/30/26	9/30/27
(i)	Maintenance Exp /MCF Produced	-	-	-	-	-
	Maintenance Exp /$1,000 MCF	-	-	-	-	-
	Maintenance Exp /$1,000 GPP	-	-	-	-	-
(ii)	Trans. Main. Exp /MMCF	-	-	-	-	-
	Trans. Main. Exp /Transmission Mile	-	-	-	-	-
	Trans. Main. Exp /$1,000 GTP	-	-	-	-	-
(iii)	Dist. Main. Exp /Customer	49.87	47.60	51.75	43.38	44.97
	Dist. Main. Exp /$1,000 GDP	7.52	6.79	6.95	5.49	5.33
(iv)	Storage. Main. Exp /MMCF Capacity	-	-	-	-	-
	Storage. Main. Exp /$1,000 GSP	-	-	-	-	-

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-34

Request:

Prepare a 3-column schedule of expenses, as described below for the following periods (supply sub-accounts, if significant, to clarify basic accounts):

a. Column 1--Test Year

b. Column 2 and 3--The two previous years

Provide the annual recorded expense by accounts. (Identify all accounts used but not specifically listed below.)

Response:

Please see Attachment III-E-34.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

Title of Account	Account Number	2025	2026	2027
Manufactured Gas Production				
Operation Supervision and Engineering	710.0	-	-	-
Production Labor and Expenses				
Steam Expenses	711.0	-	-	-
Other Power Expenses	712.0	-	-	-
Coke Oven Expenses	713.0	-	-	-
Producer Gas Expenses	714.0	-	-	-
Water Gas Generating Expenses	715.0	-	-	-
Oil Gas Generating Expenses	716.0	-	-	-
Liquefied Petroleum Gas Expenses	717.0	-	-	-
Other Process Production Expenses	718.0	-	-	-
Total Production Labor and Expenses		-	-	-
Gas Fuels				
Fuel Under Coke Ovens	719.0	-	-	-
Producer Gas Fuel	720.0	-	-	-
Water Gas Generator Fuel	721.0	-	-	-
Fuel for Oil Gas	722.0	-	-	-
Fuel for Liquefied Petroleum Gas Process	723.0	-	-	-
Other Gas Fuels	724.0	-	-	-
Total Gas Fuels Expenses		-	-	-
Gas Raw Materials				
Coal Carbonized in Coke Ovens	725.0	-	-	-
Oil for Water Gas	726.0	-	-	-
Oil for Oil Gas	727.0	-	-	-
Liquefied Petroleum Gas Expenses	728.0	-	-	-
Raw Materials for Other Gas Processes	729.0	-	-	-
Residuals Expenses	730.0	-	-	-
Residuals Produced-Credit	731.0	-	-	-
Purification Expenses	732.0	-	-	-
Gas Mixing Expenses	733.0	-	-	-
Duplicate Charges-Credit	734.0	-	-	-
Miscellaneous Production Expenses	735.0	-	-	-
Rents	736.0	-	-	-
Total Gas Raw Materials Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	740.0	-	-	-
Maintenance of Structures and Improvements	741.0		-	-
Maintenance of Production Equipment	742.0	-	-	-
Total Maintenance Expenses		-	-	-
Manufactured Gas Production Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

NATURAL GAS PRODUCTION EXPENSES				
Production and Gathering				
Operation				
Operating Supervision and Engineering	750.0	-	-	-
Production Maps and Records	751.0	-	-	-
Gas Wells Expenses	752.0	-	-	-
Field Lines Expenses	753.0	-	-	-
Field Compressor Station Expenses	754.0	-	-	-
Field Compressor Station Fuel and Power	755.0	-	-	-
Field Measuring and Regulating Station Expenses	756.0	-	-	-
Purification Expenses	757.0	-	-	-
Gas Well Royalties	758.0	-	-	-
Other Expenses	759.0	-	-	-
Rents	760.0	-	-	-
Total Production & Gathering Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	761.0	-	-	-
Maintenance of Structures and Improvements	762.0	-	-	-
Maintenance of Producing Gas Wells	763.0	-	-	-
Maintenance of Field Lines	764.0	-	-	-
Maintenance of Field Compressor Station Equipment	765.0	-	-	-
Maintenance of Field Measuring and Reg. Station Equip.	766.0	-	-	-
Maintenance of Purification Equipment	767.0	-	-	-
Maintenance of Drilling and Cleaning Equipment	768.0	-	-	-
Maintenance of Other Equipment	769.0	-	-	-
Total Production & Gathering Maintenance Expenses		-	-	-
Products Extraction				
Operation				
Operation Supervision and Engineering	770.0	-	-	-
Operating Labor	771.0	-	-	-
Gas Shrinkage	772.0	-	-	-
Fuel	773.0	-	-	-
Power	774.0	-	-	-
Materials	775.0	-	-	-
Operation Supplies and Expenses	776.0	-	-	-
Gas Processed by Others	777.0	-	-	-
Royalties on Products Extracted	778.0	-	-	-
Marketing Expenses	779.0	-	-	-
Products Purchased for Resale	780.0	-	-	-
Variation in Products Inventory	781.0	-	-	-
Extracted Products Used by the Utility-Credit	782.0	-	-	-
Rents	783.0	-	-	-
Total Products Extraction Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	784.0	-	-	-
Maintenance of Structures and Improvements	785.0	-	-	-
Maintenance of Extraction and Refining Equipment	786.0	-	-	-
Maintenance of Pipe Lines	787.0	-	-	-
Maintenance of Extracted Products Storage Equipment	788.0	-	-	-
Maintenance of Compressor Equipment	789.0	-	-	-
Maintenance of Gas Measuring & Regulating Equipment	790.0	-	-	-
Maintenance of Other Equipment	791.0	-	-	-
Total Products Extraction Maintenance Expenses		-	-	-
Total Natural Gas Production Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

EXPLORATION AND DEVELOPMENT EXPENSES				
Operation				
Delay Rentals	795.0	-	-	-
Nonproductive Well Drilling	796.0	-	-	-
Abandoned Leases	797.0	-	-	-
Other Exploration	798.0	-	-	-
Total Exploration and Development Operation Exp.		-	-	-
OTHER GAS SUPPLY EXPENSES				
Operation				
Natural Gas Well Head Purchases	800.0	-	-	-
Natural Gas Well Head Purchases, Intercompany Trans.	801.0	-	-	-
Natural Gas Gasoline Plant Outlet Purchases	802.0	-	-	-
Natural Gas Transmission Line Purchases	803.0	-	-	-
Natural Gas City Gate Purchases	804.0	466,841	530,074	530,074
Liquefied Natural Gas Purchases	804.1	311	-	-
Other Gas Purchases	805.0	1,171	5	5
Purchases Gas Cost Adjustments	805.1	(102,299)	(86,489)	(81,826)
Exchange Gas	806.0	-	-	-
Purchased Gas Expenses	807.0	-	-	-
Gas Withdrawn from Storage-Debit	808.1	36,491	47,230	47,230
Gas Delivered to Storage-Credit	808.2	(49,027)	(62,675)	(62,675)
Withdrawals of Liquefied Nat. Gas Held for Processing	809.1	-	-	-
Deliveries of Natural Gas for Processing	809.2	-	-	-
Gas Used for Compressor Station Fuel-Credit	810.0	-	-	-
Gas Used for Products Extraction-Credit	811.0	-	-	-
Gas Used for Other Utility Operations-Credit	812.0	(2,264)	2,169	2,169
Other Gas Supply Expenses	813.0	24,629	(5,211)	(5,256)
Gas Supply Operation Expenses		375,853	425,103	429,721
Natural Gas Storage, Terminating & Processing Exp.				
Underground Storage Expenses				
Operation Supervision and Engineering	814.0	-	-	-
Maps and Records	815.0	-	-	-
Wells Expenses	816.0	-	-	-
Lines Expenses	817.0	-	-	-
Compressor Station Expenses	818.0	-	-	-
Compressor Station Fuel and Power	819.0	-	-	-
Measuring and Regulating Station Expenses	820.0	-	-	-
Purification Expenses	821.0	-	-	-
Exploration and Development	822.0	-	-	-
Gas Losses	823.0	-	-	-
Other Expenses	824.0	-	-	-
Storage Well Royalties	825.0	-	-	-
Rents	826.0	-	-	-
Total Underground Storage Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	830.0	-	-	-
Maintenance of Structures and Improvements	831.0	-	-	-
Maintenance of Reservoirs and Wells	832.0	-	-	-
Maintenance of Lines	833.0	-	-	-
Maintenance of Compressor Station Equipment	834.0	-	-	-
Maintenance of Measuring & Regulating Station Equip.	835.0	-	-	-
Maintenance of Purification Equipment	836.0	-	-	-
Maintenance of Other Equipment	837.0	-	-	-
Total Underground Maintenance Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

Other Storage Expenses				
Operation				
Operating Supervision and Engineering	840.0	-	-	-
Operation Labor and Expenses	841.0	-	-	-
Rents	842.0	-	-	-
Fuel	842.1	-	-	-
Power	842.2	-	-	-
Gas Losses	842.3	-	-	-
Storage Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	843.1	-	-	-
Maintenance of Structures and Improvements	843.2	-	-	-
Maintenance of Gas Holders	843.3	-	-	-
Maintenance of Purification Equipment	843.4	-	-	-
Maintenance of Liquefaction Equipment	843.5	-	-	-
Maintenance of Vaporizing Equipment	843.6	-	-	-
Maintenance of Compressor Equipment	843.7	-	-	-
Maintenance of Measuring and Regulatory Equipment	843.8	-	-	-
Maintenance of Other Equipment	843.9	-	-	-
Storage Maintenance Expenses		-	-	-
LIQUEFIED NATURAL GAS TERMINATING AND PROCESSING EXPENSES				
Operation				
Operation Supervision and Engineering	844.1	-	-	-
LNG Processing Terminal Labor and Expenses	844.2	-	-	-
Liquefaction Processing Labor and Expenses	844.3	-	-	-
LNG Transportation Labor and Expenses	844.4	-	-	-
Measuring and Regulating Labor and Expenses	844.5	-	-	-
Compressor Station Labor and Expenses	844.6	-	-	-
Communication System Expenses	844.7	-	-	-
System Control and Load Dispatching	844.8	-	-	-
Fuel	845.1	-	-	-
Power	845.2	-	-	-
Rents	845.3	-	-	-
Demurrage Charges	845.4	-	-	-
Warfare Receipts-Credit	845.5	-	-	-
Processing Liquefied or Vaporized Gas by Others	845.6	-	-	-
Gas Losses	846.1	-	-	-
Other Expenses	846.2	-	-	-
Total Liq. N.G. Term & Proc. Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	847.1	-	-	-
Maintenance of Structures and Improvements	847.2	-	-	-
Maintenance of LNG Processing Terminal Equipment	847.3	-	-	-
Maintenance of LNG Transportation Equipment	847.4	-	-	-
Maintenance of Measuring and Regulating Equipment	847.5	-	-	-
Maintenance of Compressor Station Equipment	847.6	-	-	-
Maintenance of Communication Equipment	847.7	-	-	-
Maintenance of Other Equipment	847.8	-	-	-
Total Liq. N.G. Term. Proc. Maintenance Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

TRANSMISSION EXPENSES				
Operation				
Operating Supervision and Engineering	850.0	-	-	-
System Control and Load Dispatching	851.0	-	-	-
Communication System Expenses	852.0	-	-	-
Compressor Station Labor and Expenses	853.0	-	-	-
Gas for Compressor Station Fuel	854.0	-	-	-
Other Fuel and Power for Compressor Stations	855.0	-	-	-
Mains Expenses	856.0	-	-	-
Measuring and Regulating Station Expenses	857.0	-	-	-
Transmission and Compression of gas by Others	858.0	-	-	-
Other Expenses	859.0	-	-	-
Rents	860.0	-	-	-
Total Transmission Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	861.0	-	-	-
Maintenance of Structures and Improvements	862.0	-	-	-
Maintenance of Mains	863.0	-	-	-
Maintenance of Compressor Station Equipment	864.0	-	-	-
Maintenance of Measuring and Regulating Station Equip.	865.0	-	-	-
Maintenance of Communication Equipment	866.0	-	-	-
Maintenance of Other Equipment	867.0	-	-	-
Total Transmission Maintenance Expenses		-	-	-
DISTRIBUTION EXPENSES				
Operations Expense				
Operation Supervision and Engineering	870.0	5,077	5,815	6,264
Distribution Load Dispatching	871.0	2,544	3,259	3,424
Compressor Station Labor and Expenses	872.0	-	-	-
Compressor Station Fuel and Power (Major Only)	873.0	-	-	-
Mains and Services Expenses	874.0	29,397	32,965	34,590
Measuring and Regulating Station Expenses-General	875.0	2,225	2,101	2,194
Measuring and Regulating Station Expenses-Industrial	876.0	105	20	21
Measuring and Regulating Station Expenses-City Gate	877.0	435	416	456
Meter and House Regulator Expenses	878.0	3,476	3,470	3,661
Customer Installations Expenses	879.0	2,358	3,165	3,328
Other Expenses	880.0	9,545	6,989	7,219
Rents	881.0	638	643	651
Total Distribution Operation Expenses		55,800	58,843	61,808
Maintenance Expense				
Maintenance Supervision and Engineering	885.0	2,414	2,201	2,325
Maintenance of Structures and Improvements	886.0	-	-	-
Maintenance of Mains	887.0	23,934	20,684	21,659
Maintenance of Compressor Station Equipment	888.0	-	-	-
Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	2,780	2,276	2,353
Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890.0	4,082	3,809	3,991
Maintenance of Measuring & Reg. Station Equip.-City G	891.0	102	106	105
Maintenance of Services	892.0	988	673	677
Maintenance of Meters & House Regulators	893.0	20	42	40
Maintenance of Other Equipment	894.0	1,555	580	592
Construction & Maintenance	895.0	-	-	-
Total Distribution Maintenance Expenses		35,876	30,371	31,741

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2025, 2026 and 2027
($ in Thousands)

CUSTOMER ACCOUNTS EXPENSES				
Operations				
Supervision	901.0	834	826	873
Meter Reading Expenses	902.0	3,059	2,777	2,940
Customer Records & Collection Expenses	903.0	50,143	56,147	58,278
Uncollectable Accounts	904.0	16,582	20,409	20,671
Miscellaneous Customer Accounts Expenses	905.0	64	67	70
Customer Account Operations Expenses		70,683	80,226	82,832
CUSTOMER SERVICE & INFORM. EXPENSES				
Operations				
Supervision	907.0	83	84	89
Customer Assistance Expenses	908.0	932	1,040	1,099
Informational & Instructional Advertising Expenses	909.0	879	1,293	1,358
Miscellaneous Customer Service & Informational Exp.	910.0	11,995	12,347	12,447
Total Cust. Service & Inform. Operations Exp		13,890	14,764	14,993
SALES EXPENSES				
Operations				
Supervision	911.0	-	-	-
Demonstrating and Selling Expenses	912.0	670	718	758
Advertising Expenses	913.0	709	532	526
(Reserved)	914.0	-	-	-
(Reserved)	915.0	-	-	-
Miscellaneous Sales Expenses	916.0	-	-	-
Total Operation Sales Expenses		1,378	1,250	1,283
ADMINISTRATIVE AND GENERAL EXPENSES				
Operations				
Administrative and General Salaries	920.0	23,716	34,066	36,333
Office Supplies and Expenses	921.0	18,422	18,291	19,009
Administrative Expenses Transferred-Credit	922.0	-	-	-
Outside Service Employed	923.0	27,416	21,235	20,445
Property Insurance	924.0	337	394	361
Injuries and Damages	925.0	10,013	10,395	11,158
Employee Pensions and Benefits	926.0	13,271	14,063	15,367
Franchise Requirements	927.0	-	-	-
Regulatory Commission Expenses	928.0	36	1,160	2,296
Duplicate Charges-Credit	929.0	-	-	-
General Advertising Expenses	930.1	154	149	171
Miscellaneous General Expenses	930.2	1,551	1,549	1,616
Rents	931.0	50	57	77
Total A & G Operation Expenses		94,965	101,359	106,833
Maintenance				
A&G Maintenance of General Plant	932.0	4,064	5,097	5,228
A&G Maintenance of General Plant	935.0	-	-	-
Total A&G Maintenance Expenses		4,064	5,097	5,228
Total Gas Operation and Maintenance Expenses		$ 652,509	$ 717,012	$ 734,438
Total Gas Operation Expenses		$ 612,569	$ 681,544	$ 697,470
Total Gas Maintenance Expenses		39,940	35,467	36,969
Total Gas Operation and Maintenance Expenses		$ 652,509	$ 717,012	$ 734,438

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-35

Request:

Submit a schedule showing the Gross Receipts Tax Base used in computing Pennsylvania Gross Receipts Tax Adjustment.

Response:

Not applicable. UGI Gas is not subject to the Pennsylvania Gross Receipts Tax.

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-36

Request:

State the amount of gas, in mcf, obtained through various suppliers in past years.

Response:

Please see Book I, Attachment 1-A-1 of the 2025 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2025-3054938 which can be found at URL https://www.puc.pa.gov/pcdocs/1877400.pdf.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-37

Request:

In determining pro forma expense, exclude cost of gas adjustments applicable to fuel adjustment clause and exclude fuel adjustment clause revenues, so that the operating statement is on the basis of base rates only.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-6.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-38

Request:

Identify company's policy with respect to replacing customers lost through attrition.

Response:

UGI Gas has not experienced attrition on a total customer basis. The Company actively seeks opportunities to add new customers, including new construction and conversion customers, and adds these customers to the extent they meet the requirements of the Company's Tariff.

Prepared by or under the supervision of: Hans G. Bell

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Section 53.53 - III-E - Balance Sheet and
Operating Statement - Gas Utilities
Delivered on January 28, 2026

III-E-39

Request:

Identify procedures developed to govern relationship between the respondent and potential customers--i.e., basically expansion, alternate energy requirements, availability of supply, availability of distribution facilities, ownership of metering and related facilities.

Response:

Please refer to UGI Gas Exhibit F, Rule 5, Extension Regulation, of the Tariff for UGI Utilities, Inc. - Gas Division.

Prepared by or under the supervision of: Sherry A. Epler

SECTION 53.53 – RATE STRUCTURE

IV-B-1

Request:

Provide a Cost of Service Study showing the rate of return under the present and proposed tariffs for all customer classifications. The study should include a summary of the allocated measures of value, operating revenues, operating expenses and net return for each of the customer classifications at original cost and at the 5-year trended original cost.

a. (Reserved)

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: John D. Taylor

IV-B-2

Request:

Provide a statement of testimony describing the complete methodology of the cost of service study.

Response:

Please refer to UGI Gas Exhibit D and Direct Testimony of John D. Taylor, UGI Gas Statement No. 11.

Prepared by or under the supervision of: John D. Taylor

IV-B-3

Request:

Provide a complete description and back-up calculations for all allocation factors.

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: John D. Taylor

IV-B-4

Request:

Provide an exhibit for each customer classification showing the following data for the test year and the four previous years:

a. The maximum coincident peak day demand.

b. The maximum coincident 3-day peak day demand.

c. The average monthly consumption in MCF during the Primary Heating Season (November-March).

d. The average monthly consumption in MCF during the Non-heating season (April-October).

e. The average daily consumption in MCF for each 12-month period.

Response:

Please see Attachments IV-B-4 (a)-(e).

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Coincident Peak Day Demand

Winter Season	Peak Day Date	Volume (Mdth)
2024-2025	2/18/2025	1,694.6
2023-2024	1/17/2024	1,705.6
2022-2023	2/3/2023	1,648.9
2021-2022	1/15/2022	1,679.1
2020-2021	1/28/2021	1,531.0
2019-2020	2/14/2020	1,564.5
2018-2019	3/6/2019	1,626.5
2017-2018	1/5/2018	1,420.9

UGI UTILITIES, INC. - GAS DIVISION
COINCIDENT 3 DAY PEAK PERIODS
SENDOUT BY RATE CLASS

	2020-2021			2021-2022			2022-2023			2023-2024			2024-2025		
	JAN 27	JAN 28	JAN 29	JAN 29	JAN 30	JAN 31	FEB 2	FEB 3	FEB 4	JAN 15	JAN 16	JAN 17	FEB 18	FEB 19	FEB 20
	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)
RG	2.2	2.8	2.9	3.6	3.2	2.9	2.0	3.3	2.7	2.2	2.5	2.6	2.9	2.7	2.8
RH	290.9	375.1	387.4	484.0	424.2	387.6	303.9	505.9	408.0	372.8	424.8	445.6	461.5	431.7	441.4
CG	3.1	4.0	4.1	5.1	4.5	4.1	4.4	7.4	5.9	4.2	4.8	5.0	5.8	5.4	5.5
CH	105.5	136.1	140.5	175.6	153.9	140.6	117.2	195.1	157.3	136.5	155.6	163.2	174.7	163.5	167.1
IG	0.8	1.1	1.1	1.4	1.2	1.1	0.9	1.6	1.3	1.9	2.2	2.3	2.0	1.8	1.9
IH	4.9	6.4	6.6	8.2	7.2	6.6	6.4	10.7	8.6	6.6	7.5	7.9	7.7	7.2	7.3
PGC FIRM	407.5	525.4	542.6	678.0	594.2	542.8	434.9	724.0	583.8	524.2	597.4	626.6	654.5	612.3	626.1
RT (CHOICE)	43.4	43.8	44.0	45.7	45.7	45.7	31.0	30.9	30.8	38.9	39.1	39.1	39.2	38.7	38.0
NT (CHOICE)	78.7	79.3	79.7	84.1	84.1	84.1	65.5	65.3	65.0	81.1	81.5	81.6	81.7	80.5	79.2
DS	56.8	65.8	64.3	69.6	67.8	67.8	54.5	70.8	59.1	61.5	67.8	70.0	70.9	67.3	68.0
LFD	100.0	105.4	97.5	96.7	99.3	111.2	102.0	109.3	88.8	109.2	117.6	121.3	123.8	121.8	119.8
XD-F/CDS-F	532.1	554.7	519.3	501.5	505.2	530.4	613.8	584.6	649.6	697.1	705.6	706.6	667.3	666.4	691.6
FIRM TRANSPORTATION	810.9	849.0	804.8	797.6	802.0	839.1	866.9	860.9	893.3	987.9	1,011.5	1,018.6	982.8	974.6	996.6
INTERRUPTIBLE	154.8	156.5	109.8	74.8	89.4	98.6	61.8	64.0	56.6	71.7	70.2	60.4	57.3	60.6	58.0
TOTAL	1,373.2	1,531.0	1,457.2	1,550.4	1,485.5	1,480.6	1,363.6	1,648.9	1,533.7	1,583.8	1,679.1	1,705.6	1,694.6	1,647.4	1,680.7

UGI Utilities, Inc. - Gas Division

Average Monthly Consumption in MCF during Primary Heating Season (November-March)

	Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT RT Total	Rate N Commercial-Non Htg	Rate N Commercial-Htg	Rate N Industrial-Non Htg	Rate N Industrial-Htg	Rate NT NT Total	Rate DS DS Total	Rate LFD,XD,IS Large Transp-Other
2021	48,043	6,386,277	974,183	76,612	2,262,056	16,769	107,176	1,764,937	1,223,098	19,188,476
2022	44,929	6,728,008	953,007	93,658	2,487,940	17,929	126,796	1,864,031	1,275,504	19,613,866
2023	41,795	6,208,101	836,419	102,757	2,329,735	21,331	122,517	1,722,567	1,193,899	20,270,840
2024	38,354	5,980,709	919,951	75,757	2,126,114	15,033	94,797	1,918,952	1,209,548	20,669,394
2025	41,821	6,808,076	987,310	89,675	2,475,915	21,550	105,275	2,081,315	1,258,812	19,950,263

Utilities, Inc. - Gas Division
Average Monthly Consumption in MCF during the Non-Heating Season (April-October)

	Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT Total RT	Rate N Commercial-Non Htg	Rate N Commercial-Htg	Rate N Industrial-Non Htg	Rate N Industrial-Htg	Rate NT Total NT	Rate DS Total DS	Rate LFD,XD,IS Large Transp-Other
2021	20,964	1,245,344	183,396	41,468	465,191	6,678	23,824	521,574	380,139	17,574,725
2022	20,737	1,415,849	202,476	57,454	545,696	8,724	27,284	557,150	442,817	18,777,979
2023	19,220	1,253,916	187,143	44,263	461,587	3,948	19,176	566,942	421,162	20,106,380
2024	18,545	1,244,837	183,238	41,404	434,027	4,244	14,500	580,556	423,175	19,436,098
2025	18,050	1,272,476	189,303	41,789	478,506	6,804	14,816	583,108	410,583	18,322,708

UGI Utilities, Inc. - Gas Division
Average Daily Consumption in MCF for each 12-Month period

	Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT Total RT	Rate N Commercial-Non Htg	Rate N Commercial-Htg	Rate N Industrial-Non Htg	Rate N Industrial-Htg	Rate NT Total NT	Rate DS Total DS	Rate LFD,XD,IS Large Transp-Other
2021	1,074	112,989	17,117	1,836	40,020	352	1,881	34,281	24,607	611,734
2022	1,007	116,595	16,575	2,356	43,320	410	2,308	35,507	25,408	617,434
2023	952	110,051	15,107	2,282	41,666	369	2,045	34,655	24,847	655,919
2024	895	105,881	16,194	1,866	37,538	293	1,594	37,739	24,596	668,694
2025	921	117,233	17,069	2,040	42,864	425	1,710	39,550	25,062	634,204

IV-B-5

Request:

Submit a Bill Frequency Analysis for each rate. The analysis should include the rate schedule and block interval, the number of bills at each interval, the cumulative number of bills at each interval, the Mcf or therms at each interval, the cumulative Mcf or therms at each interval, the accumulation of Mcf or therms passing through each interval, and the revenue at each interval for both the present rate and the proposed rates. The Analysis should show only those revenues collected from the basic tariff.

Response:

Please see Attachment IV-B-5 which has been uploaded separately via the Commission's SharePoint site. The materials will be served upon the parties via a secure OneDrive link.

Prepared by or under the supervision of: Sherry A. Epler

IV-B-6

Request:

Supply copies of all present and proposed Gas Tariffs.

Response:

Please see UGI Gas Exhibit F - Current Tariff and UGI Gas Exhibit F - Proposed Tariff Supplement.

Prepared by or under the supervision of: Sherry A. Epler

IV-B-7

Request:

Supply a graph of present and proposed base rates on hyperbolic cross section paper.

Response:

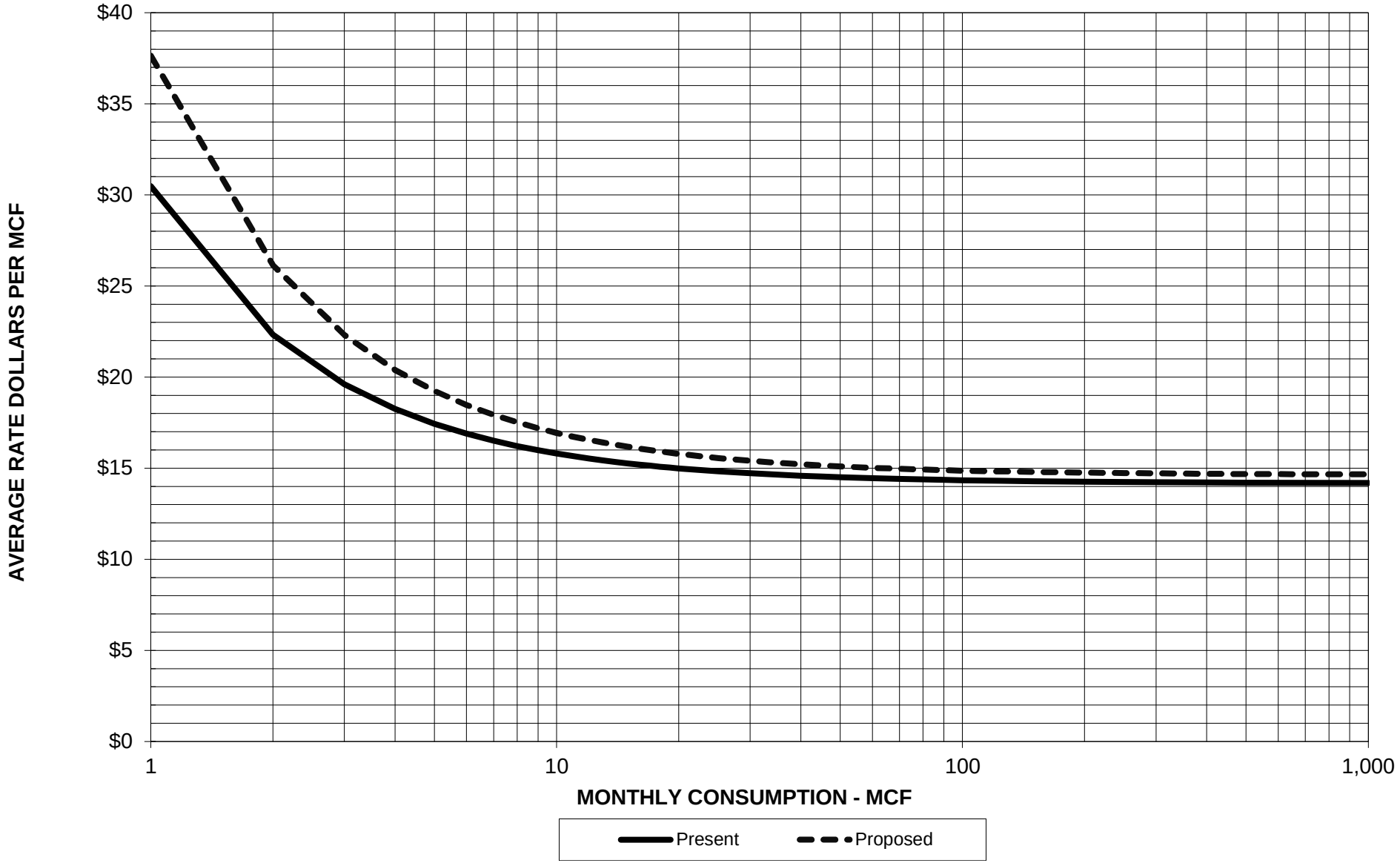
Please see Attachment IV-B-7.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential Service - Rate Schedule R
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 16.31	$ 23.00	$ 6.69	41.1%
1	$ 30.48	$ 37.64	$ 7.16	23.5%
2	$ 44.66	$ 52.29	$ 7.63	17.1%
3	$ 58.83	$ 66.93	$ 8.10	13.8%
4	$ 73.01	$ 81.57	$ 8.57	11.7%
5	$ 87.18	$ 96.22	$ 9.03	10.4%
6	$ 101.36	$ 110.86	$ 9.50	9.4%
7	$ 115.53	$ 125.50	$ 9.97	8.6%
8	$ 129.71	$ 140.15	$ 10.44	8.0%
9	$ 143.88	$ 154.79	$ 10.91	7.6%
10	$ 158.06	$ 169.43	$ 11.37	7.2%
11	$ 172.23	$ 184.07	$ 11.84	6.9%
12	$ 186.41	$ 198.72	$ 12.31	6.6%
13	$ 200.58	$ 213.36	$ 12.78	6.4%
14	$ 214.76	$ 228.00	$ 13.25	6.2%
15	$ 228.93	$ 242.65	$ 13.71	6.0%
16	$ 243.11	$ 257.29	$ 14.18	5.8%
17	$ 257.28	$ 271.93	$ 14.65	5.7%
18	$ 271.46	$ 286.58	$ 15.12	5.6%
19	$ 285.63	$ 301.22	$ 15.59	5.5%
20	$ 299.81	$ 315.86	$ 16.05	5.4%
25	$ 370.69	$ 389.08	$ 18.39	5.0%
30	$ 441.56	$ 462.29	$ 20.73	4.7%
35	$ 512.44	$ 535.51	$ 23.07	4.5%
40	$ 583.31	$ 608.73	$ 25.41	4.4%
45	$ 654.19	$ 681.94	$ 27.75	4.2%
50	$ 725.07	$ 755.16	$ 30.09	4.2%
60	$ 866.82	$ 901.59	$ 34.77	4.0%
70	$ 1,008.57	$ 1,048.02	$ 39.45	3.9%
80	$ 1,150.32	$ 1,194.45	$ 44.13	3.8%
90	$ 1,292.07	$ 1,340.88	$ 48.81	3.8%
100	$ 1,433.83	$ 1,487.31	$ 53.49	3.7%
125	$ 1,788.21	$ 1,853.39	$ 65.19	3.6%
150	$ 2,142.59	$ 2,219.47	$ 76.89	3.6%
200	$ 2,851.35	$ 2,951.63	$ 100.28	3.5%
250	$ 3,560.11	$ 3,683.79	$ 123.68	3.5%
300	$ 4,268.87	$ 4,415.94	$ 147.08	3.4%
400	$ 5,686.39	$ 5,880.26	$ 193.87	3.4%
500	$ 7,103.91	$ 7,344.57	$ 240.66	3.4%
1,000	$ 14,191.51	$ 14,666.14	$ 474.63	3.3%

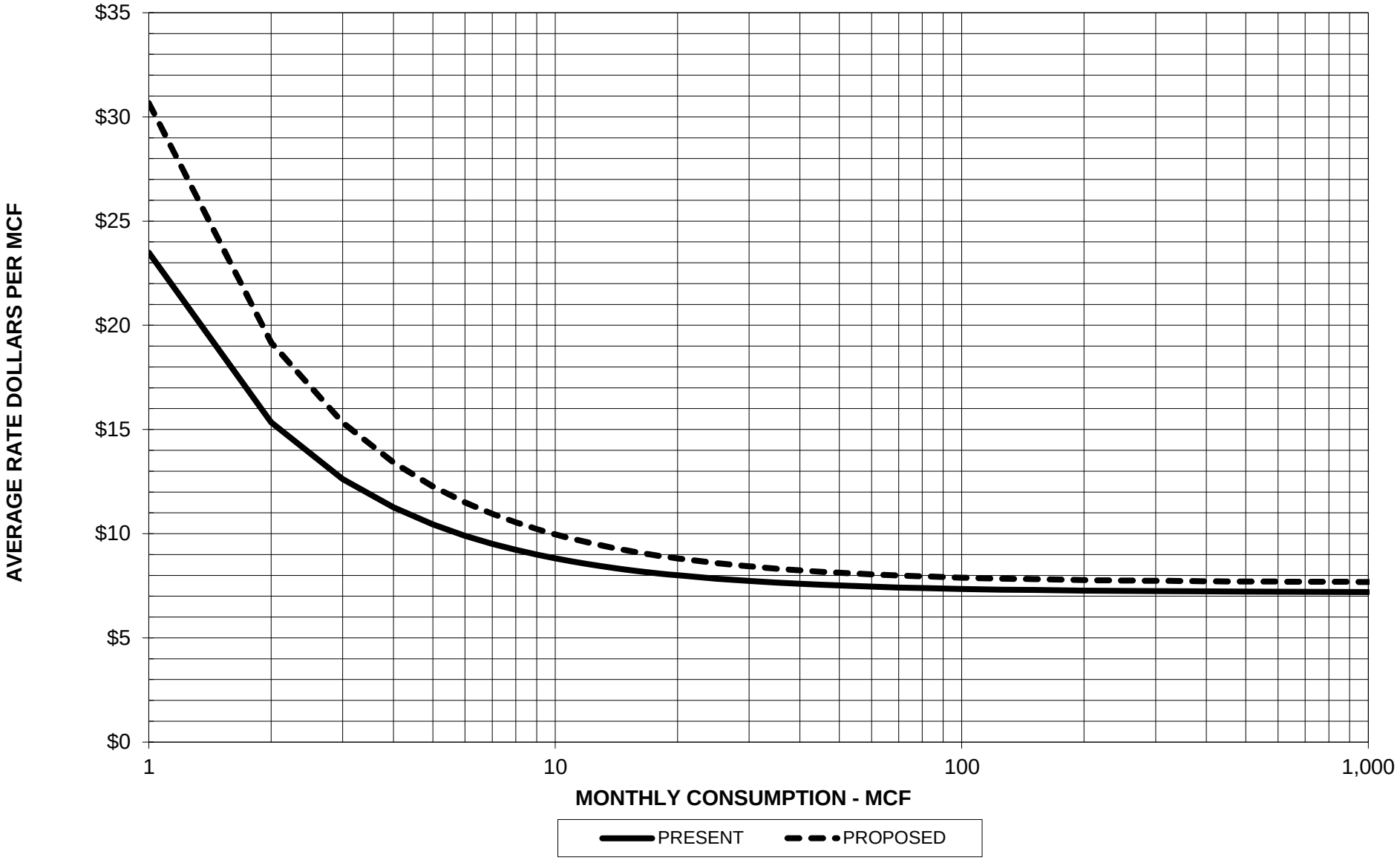
UGI Utilities, Inc.- Gas Division
Comparison of Present and Proposed Rates
Rate Schedule R



UGI Utilities, Inc. - Gas Division
Residential Transportation Service - Rate Schedule RT
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 16.31	$ 23.00	$ 6.69	41.1%
1	$ 23.49	$ 30.67	$ 7.18	30.6%
2	$ 30.68	$ 38.34	$ 7.66	25.0%
3	$ 37.86	$ 46.01	$ 8.14	21.5%
4	$ 45.05	$ 53.67	$ 8.62	19.1%
5	$ 52.24	$ 61.34	$ 9.11	17.4%
6	$ 59.42	$ 69.01	$ 9.59	16.1%
7	$ 66.61	$ 76.68	$ 10.07	15.1%
8	$ 73.80	$ 84.35	$ 10.55	14.3%
9	$ 80.98	$ 92.02	$ 11.03	13.6%
10	$ 88.17	$ 99.69	$ 11.52	13.1%
11	$ 95.36	$ 107.35	$ 12.00	12.6%
12	$ 102.54	$ 115.02	$ 12.48	12.2%
13	$ 109.73	$ 122.69	$ 12.96	11.8%
14	$ 116.91	$ 130.36	$ 13.45	11.5%
15	$ 124.10	$ 138.03	$ 13.93	11.2%
16	$ 131.29	$ 145.70	$ 14.41	11.0%
17	$ 138.47	$ 153.37	$ 14.89	10.8%
18	$ 145.66	$ 161.03	$ 15.38	10.6%
19	$ 152.85	$ 168.70	$ 15.86	10.4%
20	$ 160.03	$ 176.37	$ 16.34	10.2%
25	$ 195.96	$ 214.72	$ 18.75	9.6%
30	$ 231.90	$ 253.06	$ 21.16	9.1%
35	$ 267.83	$ 291.40	$ 23.57	8.8%
40	$ 303.76	$ 329.74	$ 25.98	8.6%
45	$ 339.69	$ 368.09	$ 28.40	8.4%
50	$ 375.62	$ 406.43	$ 30.81	8.2%
60	$ 447.49	$ 483.12	$ 35.63	8.0%
70	$ 519.35	$ 559.80	$ 40.45	7.8%
80	$ 591.21	$ 636.49	$ 45.27	7.7%
90	$ 663.08	$ 713.17	$ 50.10	7.6%
100	$ 734.94	$ 789.86	$ 54.92	7.5%
125	$ 914.60	$ 981.58	$ 66.98	7.3%
150	$ 1,094.26	$ 1,173.29	$ 79.03	7.2%
200	$ 1,453.58	$ 1,556.72	$ 103.14	7.1%
250	$ 1,812.89	$ 1,940.15	$ 127.26	7.0%
300	$ 2,172.21	$ 2,323.58	$ 151.37	7.0%
400	$ 2,890.85	$ 3,090.44	$ 199.59	6.9%
500	$ 3,609.48	$ 3,857.30	$ 247.82	6.9%
1,000	$ 7,202.66	$ 7,691.60	$ 488.94	6.8%

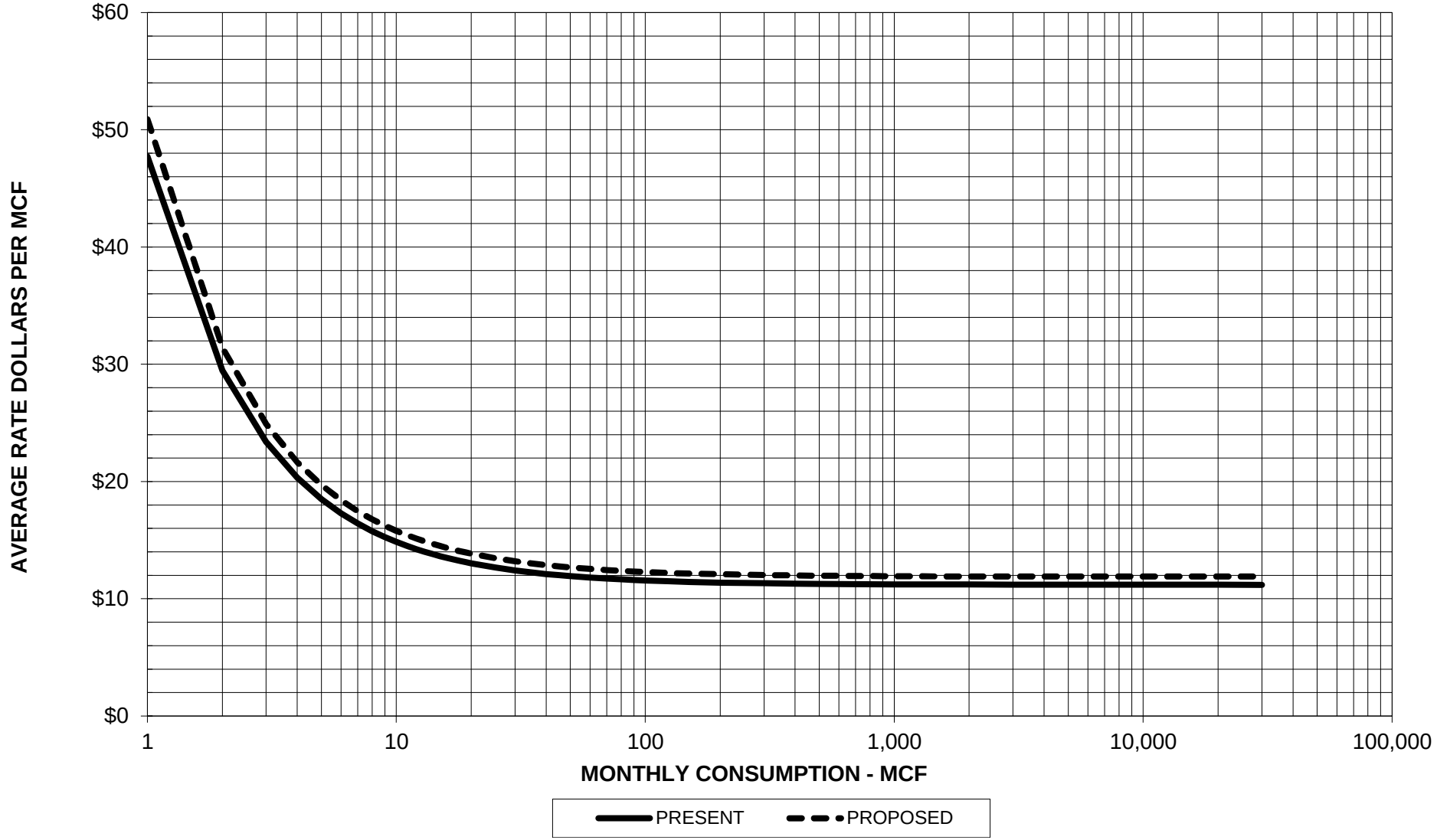
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule RT



UGI Utilities, Inc. - Gas Division
Non-Residential Service - Rate Schedule N
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 36.54	$ 39.00	$ 2.46	6.7%
1	$ 47.74	$ 50.90	$ 3.16	6.6%
2	$ 58.93	$ 62.80	$ 3.87	6.6%
3	$ 70.13	$ 74.71	$ 4.58	6.5%
4	$ 81.32	$ 86.61	$ 5.29	6.5%
5	$ 92.52	$ 98.51	$ 5.99	6.5%
6	$ 103.71	$ 110.41	$ 6.70	6.5%
7	$ 114.90	$ 122.31	$ 7.41	6.4%
8	$ 126.10	$ 134.22	$ 8.12	6.4%
9	$ 137.29	$ 146.12	$ 8.82	6.4%
10	$ 148.49	$ 158.02	$ 9.53	6.4%
11	$ 159.68	$ 169.92	$ 10.24	6.4%
12	$ 170.88	$ 181.82	$ 10.95	6.4%
13	$ 182.07	$ 193.72	$ 11.65	6.4%
14	$ 193.27	$ 205.63	$ 12.36	6.4%
15	$ 204.46	$ 217.53	$ 13.07	6.4%
16	$ 215.65	$ 229.43	$ 13.78	6.4%
17	$ 226.85	$ 241.33	$ 14.48	6.4%
18	$ 238.04	$ 253.23	$ 15.19	6.4%
19	$ 249.24	$ 265.14	$ 15.90	6.4%
20	$ 260.43	$ 277.04	$ 16.61	6.4%
25	$ 316.40	$ 336.55	$ 20.14	6.4%
30	$ 372.38	$ 396.06	$ 23.68	6.4%
35	$ 428.35	$ 455.57	$ 27.22	6.4%
40	$ 484.32	$ 515.08	$ 30.76	6.4%
45	$ 540.29	$ 574.59	$ 34.29	6.3%
50	$ 596.27	$ 634.10	$ 37.83	6.3%
60	$ 708.21	$ 753.12	$ 44.91	6.3%
70	$ 820.15	$ 872.13	$ 51.98	6.3%
80	$ 932.10	$ 991.15	$ 59.06	6.3%
90	$ 1,044.04	$ 1,110.17	$ 66.13	6.3%
100	$ 1,155.99	$ 1,229.19	$ 73.20	6.3%
125	$ 1,435.85	$ 1,526.74	$ 90.89	6.3%
150	$ 1,715.71	$ 1,824.29	$ 108.58	6.3%
200	$ 2,275.43	$ 2,419.38	$ 143.95	6.3%
250	$ 2,835.15	$ 3,014.48	$ 179.33	6.3%
300	$ 3,394.87	$ 3,609.58	$ 214.70	6.3%
400	$ 4,514.32	$ 4,799.77	$ 285.45	6.3%
500	$ 5,633.76	$ 5,989.96	$ 356.20	6.3%
1,000	$ 11,230.97	$ 11,940.92	$ 709.94	6.3%
2,000	$ 22,425.41	$ 23,842.84	$ 1,417.43	6.3%
3,000	$ 33,619.84	$ 35,744.76	$ 2,124.92	6.3%
4,000	$ 44,814.27	$ 47,646.67	$ 2,832.41	6.3%
5,000	$ 56,008.70	$ 59,548.59	$ 3,539.89	6.3%
6,000	$ 67,203.13	$ 71,450.51	$ 4,247.38	6.3%
7,000	$ 78,397.56	$ 83,352.43	$ 4,954.87	6.3%
8,000	$ 89,591.99	$ 95,254.35	$ 5,662.36	6.3%
9,000	$ 100,786.42	$ 107,156.27	$ 6,369.84	6.3%
10,000	$ 111,980.85	$ 119,058.18	$ 7,077.33	6.3%
20,000	$ 223,925.16	$ 238,077.37	$ 14,152.21	6.3%
30,000	$ 335,869.47	$ 357,096.55	$ 21,227.08	6.3%

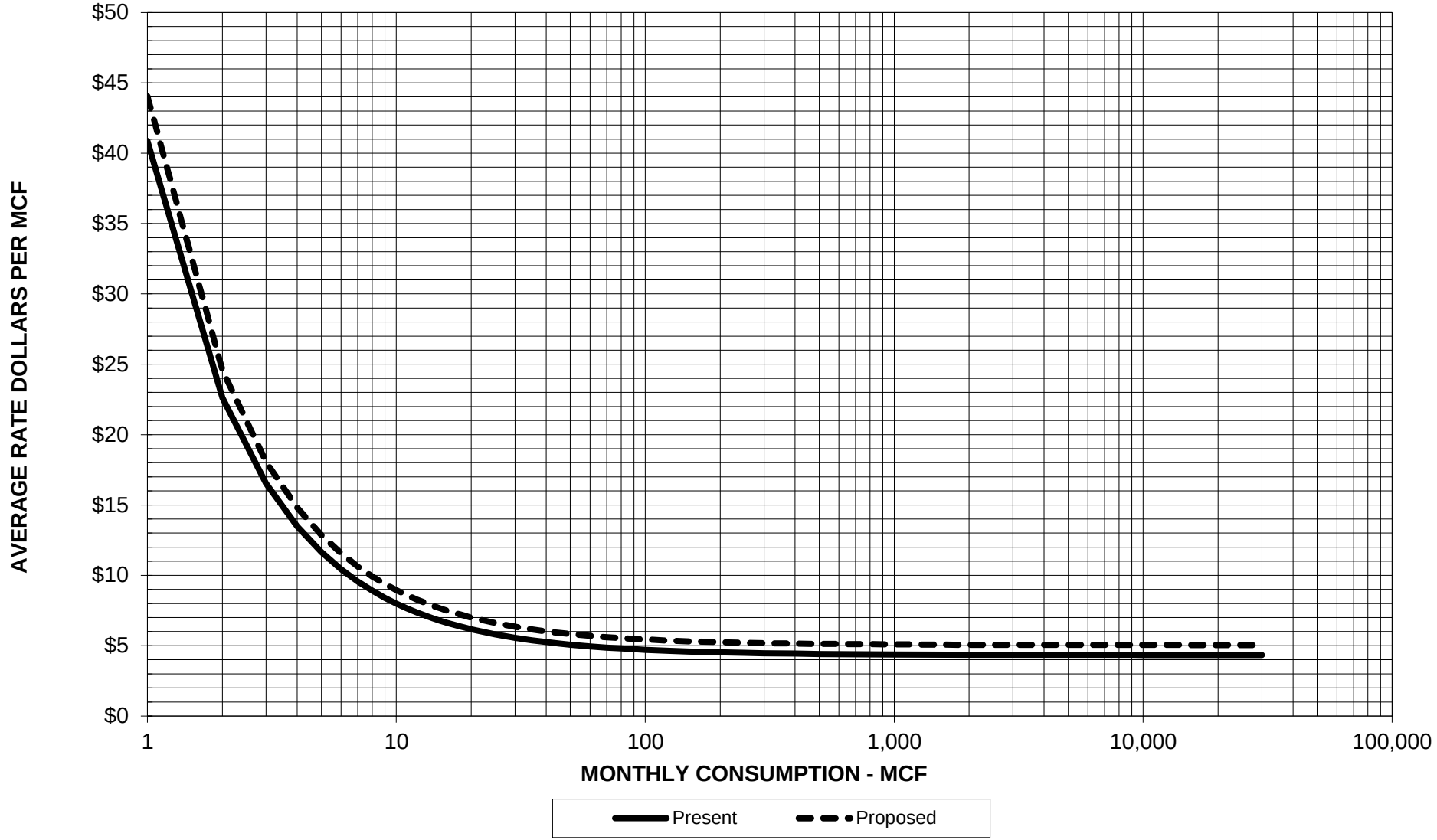
UGI Utilities, Inc.- Gas Division
Comparison of Present and Proposed Rates
Rate Schedule N



UGI Utilities, Inc. - Gas Division
Non-Residential Transportation Service - Rate Schedule NT
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 36.54	$ 39.00	$ 2.46	6.7%
1	$ 40.88	$ 44.06	$ 3.17	7.8%
2	$ 45.23	$ 49.11	$ 3.89	8.6%
3	$ 49.57	$ 54.17	$ 4.60	9.3%
4	$ 53.91	$ 59.22	$ 5.31	9.9%
5	$ 58.25	$ 64.28	$ 6.03	10.4%
6	$ 62.59	$ 69.33	$ 6.74	10.8%
7	$ 66.93	$ 74.39	$ 7.46	11.1%
8	$ 71.27	$ 79.44	$ 8.17	11.5%
9	$ 75.61	$ 84.50	$ 8.89	11.8%
10	$ 79.95	$ 89.56	$ 9.60	12.0%
11	$ 84.29	$ 94.61	$ 10.32	12.2%
12	$ 88.64	$ 99.67	$ 11.03	12.4%
13	$ 92.98	$ 104.72	$ 11.75	12.6%
14	$ 97.32	$ 109.78	$ 12.46	12.8%
15	$ 101.66	$ 114.83	$ 13.17	13.0%
16	$ 106.00	$ 119.89	$ 13.89	13.1%
17	$ 110.34	$ 124.95	$ 14.60	13.2%
18	$ 114.68	$ 130.00	$ 15.32	13.4%
19	$ 119.02	$ 135.06	$ 16.03	13.5%
20	$ 123.36	$ 140.11	$ 16.75	13.6%
25	$ 145.07	$ 165.39	$ 20.32	14.0%
30	$ 166.77	$ 190.67	$ 23.89	14.3%
35	$ 188.48	$ 215.95	$ 27.47	14.6%
40	$ 210.18	$ 241.22	$ 31.04	14.8%
45	$ 231.89	$ 266.50	$ 34.61	14.9%
50	$ 253.59	$ 291.78	$ 38.19	15.1%
60	$ 297.00	$ 342.34	$ 45.33	15.3%
70	$ 340.41	$ 392.89	$ 52.48	15.4%
80	$ 383.82	$ 443.45	$ 59.62	15.5%
90	$ 427.23	$ 494.00	$ 66.77	15.6%
100	$ 470.64	$ 544.56	$ 73.92	15.7%
125	$ 579.17	$ 670.95	$ 91.78	15.8%
150	$ 687.70	$ 797.34	$ 109.64	15.9%
200	$ 904.75	$ 1,050.12	$ 145.37	16.1%
250	$ 1,121.80	$ 1,302.90	$ 181.10	16.1%
300	$ 1,338.85	$ 1,555.68	$ 216.83	16.2%
400	$ 1,772.95	$ 2,061.24	$ 288.29	16.3%
500	$ 2,207.05	$ 2,566.80	$ 359.75	16.3%
1,000	$ 4,377.55	$ 5,094.60	$ 717.05	16.4%
2,000	$ 8,718.57	$ 10,150.20	$ 1,431.63	16.4%
3,000	$ 13,059.58	$ 15,205.80	$ 2,146.22	16.4%
4,000	$ 17,400.59	$ 20,261.40	$ 2,860.81	16.4%
5,000	$ 21,741.60	$ 25,317.00	$ 3,575.40	16.4%
6,000	$ 26,082.61	$ 30,372.60	$ 4,289.99	16.4%
7,000	$ 30,423.62	$ 35,428.20	$ 5,004.58	16.4%
8,000	$ 34,764.63	$ 40,483.80	$ 5,719.17	16.5%
9,000	$ 39,105.64	$ 45,539.40	$ 6,433.76	16.5%
10,000	$ 43,446.65	$ 50,595.00	$ 7,148.35	16.5%
20,000	$ 86,856.76	$ 101,151.00	$ 14,294.24	16.5%
30,000	$ 130,266.87	$ 151,707.00	$ 21,440.13	16.5%

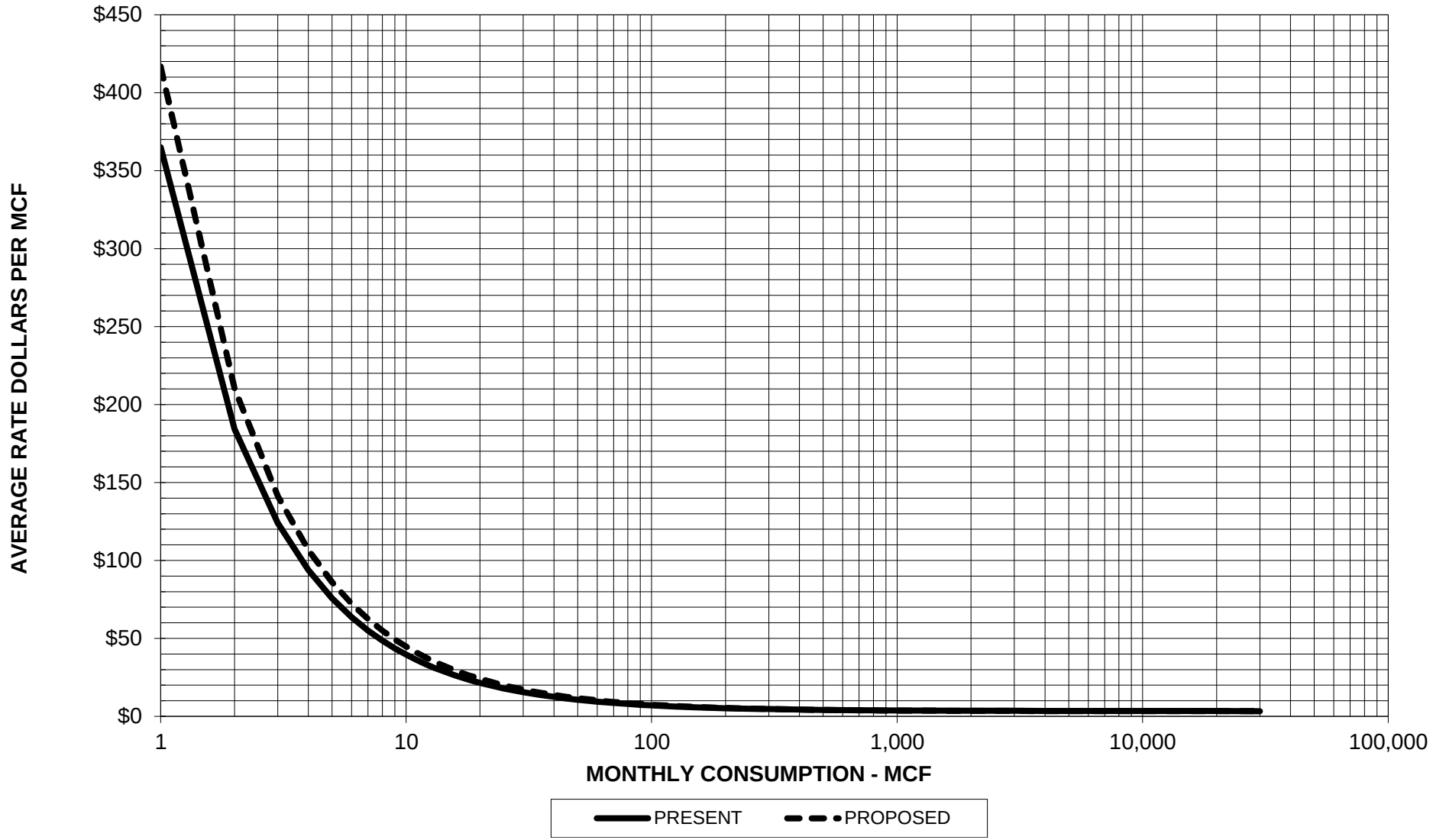
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule NT



UGI Utilities, Inc. - Gas Division
Delivery Service - Rate Schedule DS
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 361.64	$ 413.41	$ 51.77	14.3%
1	$ 365.06	$ 416.82	$ 51.76	14.2%
2	$ 368.48	$ 420.23	$ 51.75	14.0%
3	$ 371.90	$ 423.64	$ 51.74	13.9%
4	$ 375.32	$ 427.05	$ 51.73	13.8%
5	$ 378.75	$ 430.46	$ 51.72	13.7%
6	$ 382.17	$ 433.87	$ 51.71	13.5%
7	$ 385.59	$ 437.28	$ 51.69	13.4%
8	$ 389.01	$ 440.69	$ 51.68	13.3%
9	$ 392.43	$ 444.11	$ 51.67	13.2%
10	$ 395.86	$ 447.52	$ 51.66	13.1%
11	$ 399.28	$ 450.93	$ 51.65	12.9%
12	$ 402.70	$ 454.34	$ 51.64	12.8%
13	$ 406.12	$ 457.75	$ 51.63	12.7%
14	$ 409.54	$ 461.16	$ 51.61	12.6%
15	$ 412.97	$ 464.57	$ 51.60	12.5%
16	$ 416.39	$ 467.98	$ 51.59	12.4%
17	$ 419.81	$ 471.39	$ 51.58	12.3%
18	$ 423.23	$ 474.80	$ 51.57	12.2%
19	$ 426.65	$ 478.21	$ 51.56	12.1%
20	$ 430.08	$ 481.62	$ 51.54	12.0%
25	$ 447.19	$ 498.67	$ 51.49	11.5%
30	$ 464.30	$ 515.73	$ 51.43	11.1%
35	$ 481.41	$ 532.78	$ 51.37	10.7%
40	$ 498.52	$ 549.83	$ 51.31	10.3%
45	$ 515.63	$ 566.88	$ 51.26	9.9%
50	$ 532.74	$ 583.94	$ 51.20	9.6%
60	$ 566.96	$ 618.04	$ 51.08	9.0%
70	$ 601.18	$ 652.15	$ 50.97	8.5%
80	$ 635.40	$ 686.25	$ 50.85	8.0%
90	$ 669.62	$ 720.36	$ 50.74	7.6%
100	$ 703.84	$ 754.46	$ 50.62	7.2%
125	$ 789.39	$ 839.72	$ 50.34	6.4%
150	$ 874.94	$ 924.99	$ 50.05	5.7%
200	$ 1,046.04	$ 1,095.51	$ 49.48	4.7%
250	$ 1,217.14	$ 1,266.04	$ 48.90	4.0%
300	$ 1,388.24	$ 1,436.56	$ 48.33	3.5%
400	$ 1,730.43	$ 1,777.61	$ 47.18	2.7%
500	$ 2,072.63	$ 2,118.66	$ 46.03	2.2%
1,000	$ 3,783.63	$ 3,823.91	$ 40.28	1.1%
2,000	$ 7,205.63	$ 7,234.41	$ 28.78	0.4%
3,000	$ 10,627.63	$ 10,644.91	$ 17.29	0.2%
4,000	$ 14,049.62	$ 14,055.41	$ 5.79	0.0%
5,000	$ 17,471.62	$ 17,465.91	$ (5.71)	0.0%
6,000	$ 20,893.62	$ 20,876.41	$ (17.20)	-0.1%
7,000	$ 24,315.61	$ 24,286.91	$ (28.70)	-0.1%
8,000	$ 27,737.61	$ 27,697.41	$ (40.20)	-0.1%
9,000	$ 31,159.60	$ 31,107.91	$ (51.69)	-0.2%
10,000	$ 34,581.60	$ 34,518.41	$ (63.19)	-0.2%
20,000	$ 68,801.57	$ 68,623.41	$ (178.16)	-0.3%
30,000	$ 103,021.53	$ 102,728.41	$ (293.12)	-0.3%

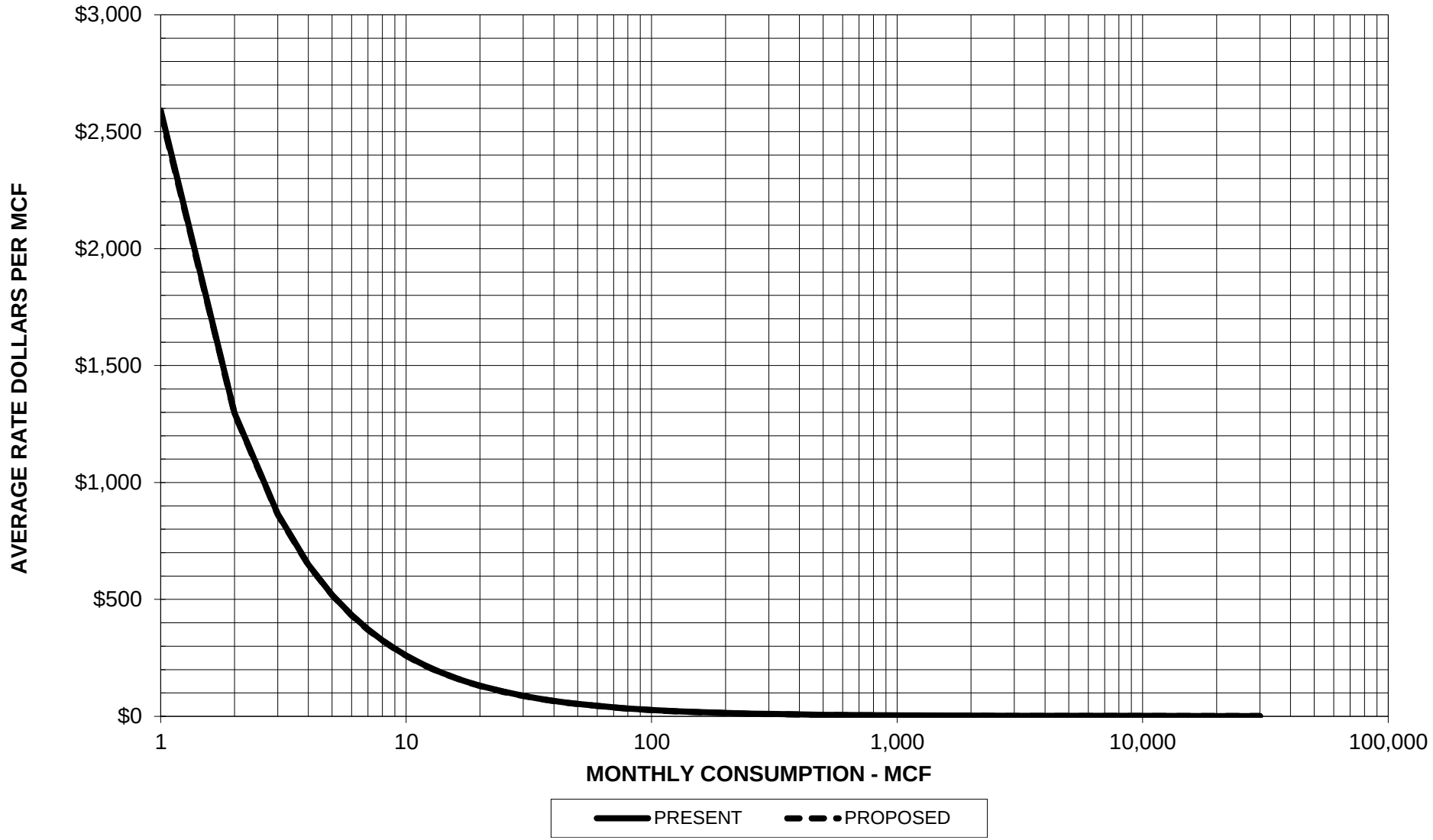
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule DS



UGI Utilities, Inc. - Gas Division
Large Firm Delivery Service - Rate Schedule LFD
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 2,590.42	$ 2,581.64	$ (8.78)	-0.3%
1	$ 2,591.84	$ 2,583.09	$ (8.75)	-0.3%
2	$ 2,593.27	$ 2,584.55	$ (8.72)	-0.3%
3	$ 2,594.69	$ 2,586.00	$ (8.69)	-0.3%
4	$ 2,596.11	$ 2,587.45	$ (8.66)	-0.3%
5	$ 2,597.54	$ 2,588.91	$ (8.63)	-0.3%
6	$ 2,598.96	$ 2,590.36	$ (8.60)	-0.3%
7	$ 2,600.39	$ 2,591.81	$ (8.57)	-0.3%
8	$ 2,601.81	$ 2,593.27	$ (8.54)	-0.3%
9	$ 2,603.23	$ 2,594.72	$ (8.51)	-0.3%
10	$ 2,604.66	$ 2,596.17	$ (8.48)	-0.3%
11	$ 2,606.08	$ 2,597.63	$ (8.46)	-0.3%
12	$ 2,607.51	$ 2,599.08	$ (8.43)	-0.3%
13	$ 2,608.93	$ 2,600.53	$ (8.40)	-0.3%
14	$ 2,610.35	$ 2,601.99	$ (8.37)	-0.3%
15	$ 2,611.78	$ 2,603.44	$ (8.34)	-0.3%
16	$ 2,613.20	$ 2,604.89	$ (8.31)	-0.3%
17	$ 2,614.63	$ 2,606.35	$ (8.28)	-0.3%
18	$ 2,616.05	$ 2,607.80	$ (8.25)	-0.3%
19	$ 2,617.48	$ 2,609.25	$ (8.22)	-0.3%
20	$ 2,618.90	$ 2,610.71	$ (8.19)	-0.3%
25	$ 2,626.02	$ 2,617.98	$ (8.04)	-0.3%
30	$ 2,633.14	$ 2,625.24	$ (7.90)	-0.3%
35	$ 2,640.26	$ 2,632.51	$ (7.75)	-0.3%
40	$ 2,647.38	$ 2,639.78	$ (7.60)	-0.3%
45	$ 2,654.50	$ 2,647.04	$ (7.46)	-0.3%
50	$ 2,661.62	$ 2,654.31	$ (7.31)	-0.3%
60	$ 2,675.86	$ 2,668.84	$ (7.02)	-0.3%
70	$ 2,690.10	$ 2,683.38	$ (6.72)	-0.2%
80	$ 2,704.34	$ 2,697.91	$ (6.43)	-0.2%
90	$ 2,718.58	$ 2,712.45	$ (6.13)	-0.2%
100	$ 2,732.82	$ 2,726.98	$ (5.84)	-0.2%
125	$ 2,768.42	$ 2,763.32	$ (5.11)	-0.2%
150	$ 2,804.02	$ 2,799.65	$ (4.37)	-0.2%
200	$ 2,875.22	$ 2,872.32	$ (2.90)	-0.1%
250	$ 2,946.42	$ 2,944.99	$ (1.43)	0.0%
300	$ 3,017.63	$ 3,017.66	$ 0.03	0.0%
400	$ 3,160.03	$ 3,163.00	$ 2.97	0.1%
500	$ 3,302.43	$ 3,308.34	$ 5.91	0.2%
1,000	$ 4,014.44	$ 4,035.04	$ 20.60	0.5%
2,000	$ 5,438.47	$ 5,488.44	$ 49.97	0.9%
3,000	$ 6,862.49	$ 6,941.84	$ 79.35	1.2%
4,000	$ 8,286.52	$ 8,395.24	$ 108.72	1.3%
5,000	$ 9,710.54	$ 9,848.64	$ 138.10	1.4%
6,000	$ 11,134.57	$ 11,302.04	$ 167.48	1.5%
7,000	$ 12,558.59	$ 12,755.44	$ 196.85	1.6%
8,000	$ 13,982.61	$ 14,208.84	$ 226.23	1.6%
9,000	$ 15,406.64	$ 15,662.24	$ 255.60	1.7%
10,000	$ 16,830.66	$ 17,115.64	$ 284.98	1.7%
20,000	$ 31,070.91	$ 31,649.64	$ 578.73	1.9%
30,000	$ 45,311.15	$ 46,183.64	$ 872.49	1.9%

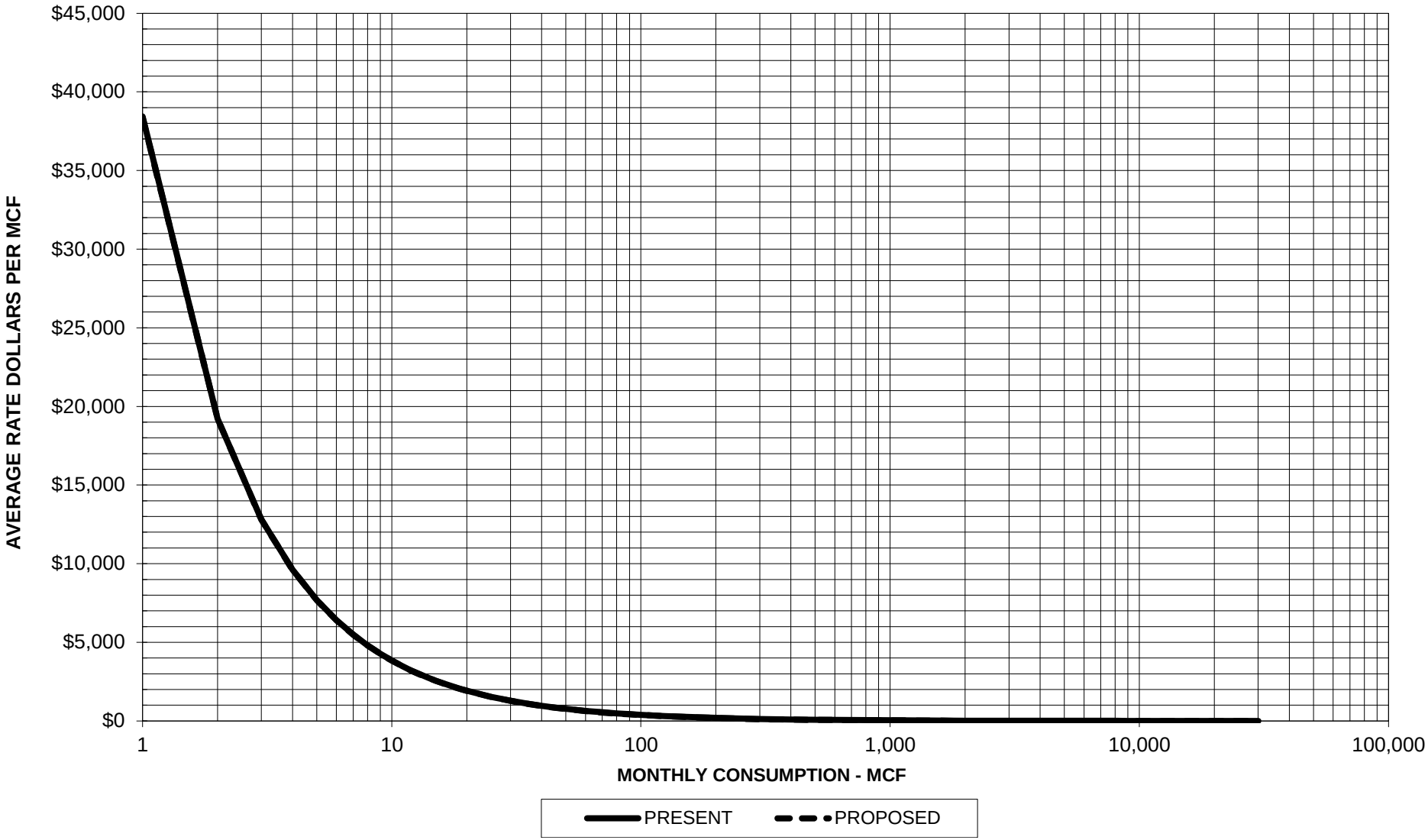
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule LFD



UGI Utilities, Inc. - Gas Division
Extended Large Firm Delivery Service - Rate Schedule XD
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 38,445.48	$ 38,382.26	$ (63.21)	-0.2%
1	$ 38,445.54	$ 38,382.33	$ (63.21)	-0.2%
2	$ 38,445.60	$ 38,382.39	$ (63.21)	-0.2%
3	$ 38,445.66	$ 38,382.45	$ (63.21)	-0.2%
4	$ 38,445.73	$ 38,382.51	$ (63.21)	-0.2%
5	$ 38,445.79	$ 38,382.58	$ (63.21)	-0.2%
6	$ 38,445.85	$ 38,382.64	$ (63.21)	-0.2%
7	$ 38,445.91	$ 38,382.70	$ (63.21)	-0.2%
8	$ 38,445.98	$ 38,382.76	$ (63.21)	-0.2%
9	$ 38,446.04	$ 38,382.83	$ (63.21)	-0.2%
10	$ 38,446.10	$ 38,382.89	$ (63.21)	-0.2%
11	$ 38,446.16	$ 38,382.95	$ (63.21)	-0.2%
12	$ 38,446.23	$ 38,383.01	$ (63.21)	-0.2%
13	$ 38,446.29	$ 38,383.08	$ (63.21)	-0.2%
14	$ 38,446.35	$ 38,383.14	$ (63.21)	-0.2%
15	$ 38,446.41	$ 38,383.20	$ (63.21)	-0.2%
16	$ 38,446.48	$ 38,383.26	$ (63.21)	-0.2%
17	$ 38,446.54	$ 38,383.32	$ (63.21)	-0.2%
18	$ 38,446.60	$ 38,383.39	$ (63.21)	-0.2%
19	$ 38,446.66	$ 38,383.45	$ (63.21)	-0.2%
20	$ 38,446.73	$ 38,383.51	$ (63.21)	-0.2%
25	$ 38,447.04	$ 38,383.82	$ (63.21)	-0.2%
30	$ 38,447.35	$ 38,384.14	$ (63.22)	-0.2%
35	$ 38,447.66	$ 38,384.45	$ (63.22)	-0.2%
40	$ 38,447.98	$ 38,384.76	$ (63.22)	-0.2%
45	$ 38,448.29	$ 38,385.07	$ (63.22)	-0.2%
50	$ 38,448.60	$ 38,385.39	$ (63.22)	-0.2%
60	$ 38,449.23	$ 38,386.01	$ (63.22)	-0.2%
70	$ 38,449.85	$ 38,386.63	$ (63.22)	-0.2%
80	$ 38,450.48	$ 38,387.26	$ (63.22)	-0.2%
90	$ 38,451.10	$ 38,387.88	$ (63.22)	-0.2%
100	$ 38,451.73	$ 38,388.51	$ (63.22)	-0.2%
125	$ 38,453.29	$ 38,390.07	$ (63.23)	-0.2%
150	$ 38,454.86	$ 38,391.63	$ (63.23)	-0.2%
200	$ 38,457.98	$ 38,394.75	$ (63.23)	-0.2%
250	$ 38,461.11	$ 38,397.87	$ (63.24)	-0.2%
300	$ 38,464.24	$ 38,401.00	$ (63.24)	-0.2%
400	$ 38,470.49	$ 38,407.24	$ (63.25)	-0.2%
500	$ 38,476.75	$ 38,413.48	$ (63.26)	-0.2%
1,000	$ 38,508.02	$ 38,444.70	$ (63.32)	-0.2%
2,000	$ 38,570.56	$ 38,507.14	$ (63.42)	-0.2%
3,000	$ 38,633.10	$ 38,569.58	$ (63.52)	-0.2%
4,000	$ 38,695.64	$ 38,632.02	$ (63.62)	-0.2%
5,000	$ 38,758.18	$ 38,694.46	$ (63.73)	-0.2%
6,000	$ 38,820.72	$ 38,756.90	$ (63.83)	-0.2%
7,000	$ 38,883.27	$ 38,819.33	$ (63.93)	-0.2%
8,000	$ 38,945.81	$ 38,881.77	$ (64.04)	-0.2%
9,000	$ 39,008.35	$ 38,944.21	$ (64.14)	-0.2%
10,000	$ 39,070.89	$ 39,006.65	$ (64.24)	-0.2%
20,000	$ 39,696.31	$ 39,631.04	$ (65.27)	-0.2%
30,000	$ 40,321.72	$ 40,255.42	$ (66.30)	-0.2%

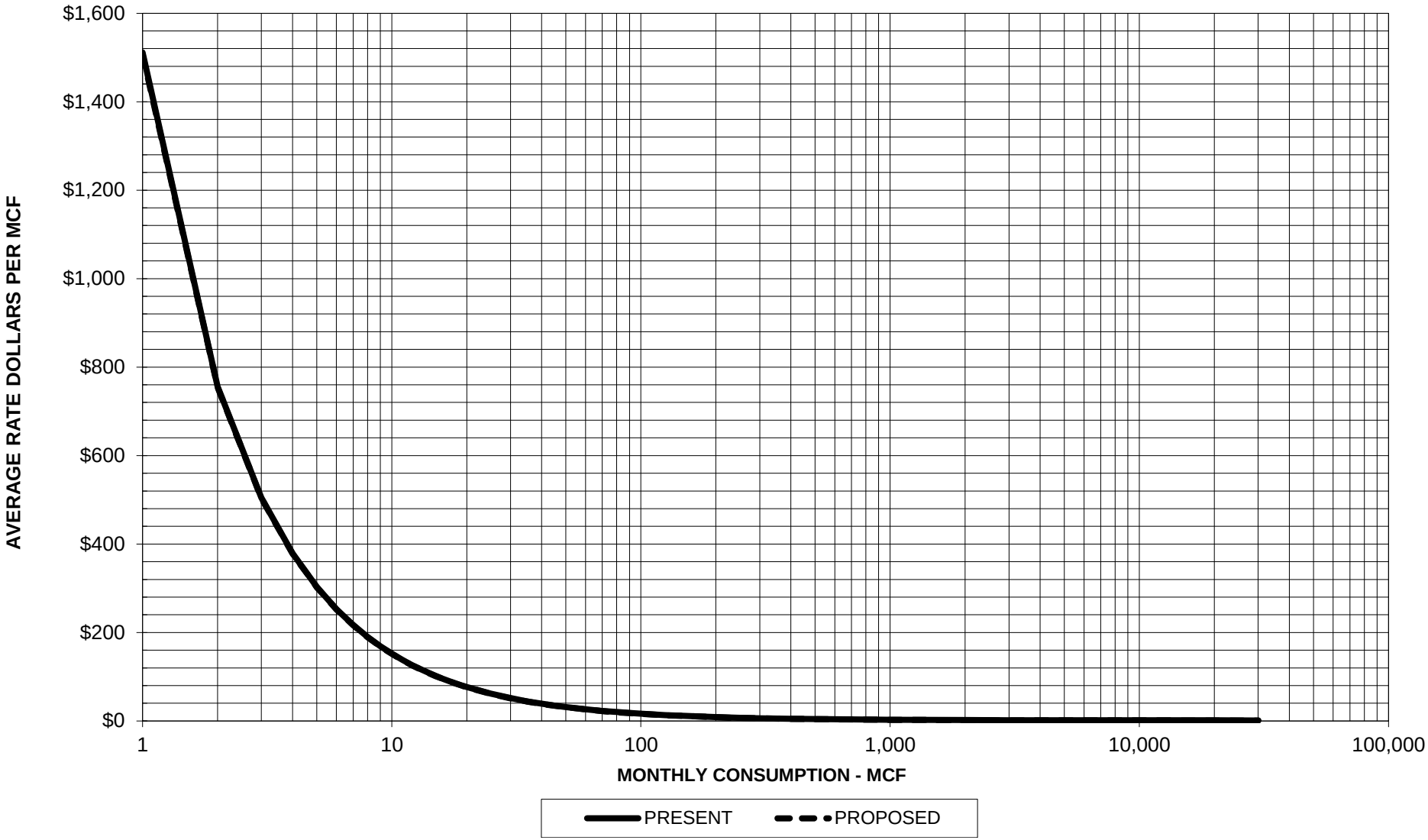
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule XD



UGI Utilities, Inc. - Gas Division
Interruptible Service - Rate Schedule IS
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 1,510.43	$ 1,505.60	$ (4.83)	-0.3%
1	$ 1,511.63	$ 1,506.80	$ (4.83)	-0.3%
2	$ 1,512.83	$ 1,508.00	$ (4.83)	-0.3%
3	$ 1,514.03	$ 1,509.19	$ (4.84)	-0.3%
4	$ 1,515.23	$ 1,510.39	$ (4.84)	-0.3%
5	$ 1,516.44	$ 1,511.59	$ (4.85)	-0.3%
6	$ 1,517.64	$ 1,512.79	$ (4.85)	-0.3%
7	$ 1,518.84	$ 1,513.99	$ (4.85)	-0.3%
8	$ 1,520.04	$ 1,515.19	$ (4.86)	-0.3%
9	$ 1,521.25	$ 1,516.38	$ (4.86)	-0.3%
10	$ 1,522.45	$ 1,517.58	$ (4.86)	-0.3%
11	$ 1,523.65	$ 1,518.78	$ (4.87)	-0.3%
12	$ 1,524.85	$ 1,519.98	$ (4.87)	-0.3%
13	$ 1,526.05	$ 1,521.18	$ (4.88)	-0.3%
14	$ 1,527.26	$ 1,522.38	$ (4.88)	-0.3%
15	$ 1,528.46	$ 1,523.57	$ (4.88)	-0.3%
16	$ 1,529.66	$ 1,524.77	$ (4.89)	-0.3%
17	$ 1,530.86	$ 1,525.97	$ (4.89)	-0.3%
18	$ 1,532.06	$ 1,527.17	$ (4.90)	-0.3%
19	$ 1,533.27	$ 1,528.37	$ (4.90)	-0.3%
20	$ 1,534.47	$ 1,529.56	$ (4.90)	-0.3%
25	$ 1,540.48	$ 1,535.56	$ (4.92)	-0.3%
30	$ 1,546.49	$ 1,541.55	$ (4.94)	-0.3%
35	$ 1,552.50	$ 1,547.54	$ (4.96)	-0.3%
40	$ 1,558.51	$ 1,553.53	$ (4.98)	-0.3%
45	$ 1,564.52	$ 1,559.52	$ (5.00)	-0.3%
50	$ 1,570.53	$ 1,565.51	$ (5.02)	-0.3%
60	$ 1,582.55	$ 1,577.49	$ (5.06)	-0.3%
70	$ 1,594.57	$ 1,589.48	$ (5.10)	-0.3%
80	$ 1,606.59	$ 1,601.46	$ (5.13)	-0.3%
90	$ 1,618.61	$ 1,613.44	$ (5.17)	-0.3%
100	$ 1,630.63	$ 1,625.42	$ (5.21)	-0.3%
125	$ 1,660.69	$ 1,655.38	$ (5.31)	-0.3%
150	$ 1,690.74	$ 1,685.34	$ (5.40)	-0.3%
200	$ 1,750.84	$ 1,745.25	$ (5.59)	-0.3%
250	$ 1,810.95	$ 1,805.16	$ (5.79)	-0.3%
300	$ 1,871.05	$ 1,865.07	$ (5.98)	-0.3%
400	$ 1,991.26	$ 1,984.90	$ (6.36)	-0.3%
500	$ 2,111.47	$ 2,104.72	$ (6.75)	-0.3%
1,000	$ 2,712.51	$ 2,703.84	$ (8.67)	-0.3%
2,000	$ 3,914.60	$ 3,902.09	$ (12.51)	-0.3%
3,000	$ 5,116.68	$ 5,100.33	$ (16.35)	-0.3%
4,000	$ 6,318.77	$ 6,298.58	$ (20.19)	-0.3%
5,000	$ 7,520.85	$ 7,496.82	$ (24.03)	-0.3%
6,000	$ 8,722.94	$ 8,695.06	$ (27.87)	-0.3%
7,000	$ 9,925.02	$ 9,893.31	$ (31.71)	-0.3%
8,000	$ 11,127.11	$ 11,091.55	$ (35.56)	-0.3%
9,000	$ 12,329.19	$ 12,289.79	$ (39.40)	-0.3%
10,000	$ 13,531.28	$ 13,488.04	$ (43.24)	-0.3%
20,000	$ 25,552.13	$ 25,470.48	$ (81.65)	-0.3%
30,000	$ 37,572.98	$ 37,452.92	$ (120.06)	-0.3%

UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule IS



IV-B-8

Request:

Supply a map showing the Gas System Facilities and Gas Service Areas. The map should include transmission lines, distribution lines, other companies' lines interconnecting with the interconnecting points clearly designated, major compressor stations, gas storage areas and gas storage lines. The normal direction of gas flow within the transmission system should be indicated by arrows. Separate service areas within the system should be clearly designated.

Response:

Please see the response to I-C-2.

Prepared by or under the supervision of: Jill E. Walter

IV-B-9

Request:

Supply a cost analysis supporting minimum charges for all rate schedules.

Response:

Please refer to UGI Gas Exhibit D and the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11.

Prepared by or under the supervision of: John D. Taylor

IV-B-10

Request:

Supply a cost analysis supporting demand charges for all tariffs which contain demand charges.

Response:

Please refer to UGI Gas Exhibit D and the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11.

Prepared by or under the supervision of: John D. Taylor

IV-B-11

Request:

Supply the net fuel clause adjustment by month for the test year.

Response:

The Company does not have a net fuel clause adjustment.

Prepared by or under the supervision of: Tracy A. Hazenstab

IV-B-12

Request:

Supply a tabulation of base rate bills for each rate schedule comparing the existing rates to proposed rates. The tabulation should show the dollar difference and the per cent increase or decrease.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10, and the responses to IV-B-5 and IV-B-7.

Prepared by or under the supervision of: Sherry A. Epler

IV-B-13

Request:

Submit the projected demands for all customer classes for both purchased and produced gas for the three years following the test year filing.

Response:

Please reference Attachment 4-1 of UGI Gas Docket No. R-2025-3054938 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filings which can be found at URL https://www.puc.pa.gov/pcdocs/1877400.pdf.

Prepared by or under the supervision of: Tracy A. Hazenstab

IV-B-14

Request:

Supply an exhibit showing the gas deliveries to each customer class for the most recent 24 month period. The exhibit should identify the source of the gas, such as “purchased” (pipeline), “production” (includes purchases from local producers), “storage withdrawal,” “propane/air,” and “unaccounted for.”

Response:

Please see Attachment IV-B-14.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Deliveries by Rate Class (MCF)

	Rate R Residential Non Heating	Rate GL Residential Gas Lights	Rate R Residential Heating	Rate RT Residential Transportation	Rate N Commercial Non Heating	Rate GL Commercial Gas Lights	Rate N Commercial Heating	Rate N Industrial Non Heating	Rate N Industrial Heating	Rate NT Non-Residential Transportation	Rate DS Delivery Service	Rate XD Extended Large Volume Delivery Service	Rate LFD Large Firm Delivery Service	Rate IS Interruptible Service Transportation	Co Use	Unaccounted for Gas
October 2023	23,262	137	1,930,559	297,164	51,697	1,297	613,228	7,055	22,667	794,126	511,257	18,347,236	1,854,974	1,116,700	19,068	484,138
November 2023	29,087	113	4,808,981	748,154	64,853	952	1,620,425	12,465	69,485	1,559,437	1,251,765	14,126,379	2,219,196	1,179,057	28,294	155,268
December 2023	41,475	118	6,062,612	958,456	79,934	944	2,133,442	11,193	97,806	1,875,816	1,162,178	19,734,433	2,334,343	1,186,171	38,100	81,910
January 2024	46,219	120	7,859,598	1,224,662	87,011	1,000	2,873,693	40,953	138,775	2,554,372	1,464,700	18,882,691	2,789,197	1,257,035	49,524	797,233
February 2024	40,645	111	6,346,394	960,569	75,657	745	2,311,183	(804)	101,229	2,043,417	1,205,999	17,348,948	2,477,746	948,542	42,498	21,276
March 2024	33,763	119	4,825,961	707,913	66,737	948	1,691,827	11,356	66,688	1,561,720	963,099	15,583,826	2,274,953	1,004,455	36,654	(150,687)
April 2024	27,363	124	2,838,346	409,079	51,731	1,054	963,397	8,163	42,690	1,047,457	704,132	16,309,455	1,960,820	1,094,839	37,536	276,414
May 2024	21,956	127	1,207,098	176,856	44,121	1,101	399,961	4,817	9,790	572,265	410,583	15,733,005	1,683,018	910,676	25,282	44,714
June 2024	19,076	135	799,905	124,408	38,823	1,194	268,933	6,153	4,579	491,287	315,786	17,960,742	1,484,627	839,808	14,406	235,789
July 2024	14,580	123	687,493	109,856	40,911	1,345	293,123	66	10,064	460,859	315,215	18,598,558	1,460,814	837,034	14,473	227,654
August 2024	14,439	115	718,112	104,955	33,452	859	292,535	4,663	9,234	448,030	328,415	18,238,763	1,586,246	937,186	13,131	128,319
September 2024	13,279	96	565,648	89,569	34,143	587	241,307	917	8,780	367,435	345,330	17,263,657	1,548,726	986,053	14,214	275,887
October 2024	18,296	109	1,897,255	267,942	39,797	710	578,935	4,931	16,364	676,560	542,765	13,378,358	2,077,742	1,162,565	18,065	112,710
November 2024	25,072	115	3,958,282	561,424	61,834	777	1,336,923	10,559	50,824	1,270,028	836,202	13,170,149	2,122,770	1,093,843	22,436	13,995
December 2024	40,448	111	7,656,546	1,105,344	94,580	975	2,700,320	17,119	117,673	2,313,396	1,384,773	17,131,780	2,658,827	1,187,624	45,535	846,536
January 2025	55,478	115	9,912,260	1,445,997	112,334	795	3,636,348	22,481	158,620	2,986,532	1,721,890	18,626,256	3,098,345	1,049,100	57,716	620,641
February 2025	48,423	111	7,782,975	1,135,551	95,983	931	2,943,947	32,961	129,637	2,364,870	1,384,835	17,107,927	2,471,724	1,059,444	65,952	390,598
March 2025	39,113	122	4,730,315	688,232	79,214	952	1,762,036	24,630	69,623	1,471,751	966,359	15,624,520	2,328,871	1,020,139	55,891	(684,351)
April 2025	26,176	120	2,887,010	413,686	61,858	1,209	1,049,386	13,655	42,612	1,062,270	678,372	17,587,417	2,010,952	1,054,880	38,974	154,729
May 2025	18,003	114	1,276,141	184,265	37,475	647	527,151	1,970	13,070	558,708	418,158	17,277,279	1,719,690	971,573	28,391	(358,009)
June 2025	19,817	131	709,663	113,071	47,257	1,202	279,832	3,766	7,294	473,332	299,653	17,243,298	1,553,094	771,828	25,247	297,456
July 2025	14,742	116	640,960	105,445	31,854	936	271,551	15,817	5,800	418,837	286,255	16,990,037	1,513,499	764,242	17,118	122,720
August 2025	14,509	125	738,583	111,643	32,221	1,071	288,448	(3,068)	7,281	426,543	308,819	16,964,340	1,577,900	873,115	13,572	103,659
September 2025	14,569	106	604,920	98,426	39,138	798	272,311	10,278	5,373	414,527	320,651	13,821,543	1,620,864	824,152	15,718	78,541

INDEX OF CONTENTS ON ONEDRIVE

UGI UTILITIES, INC. – GAS DIVISION
2026 BASE RATE CASE
DOCKET NO. R-2025-3059523

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- (Fully Projected, Future and Historic)

UGI Gas Exhibit B – Rate of Return
UGI Gas Exhibit E – Proof of Revenue

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BOOK VII - UGI Gas Exhibit C – Depreciation Study – Future

BOOK VIII - UGI Gas Exhibit C – Depreciation Study – Historic

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BOOK II

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

SUPPLEMENTAL DATA REQUESTS – COST OF SERVICE
SUPPLEMENTAL DATA REQUESTS – RATE OF RETURN
SUPPLEMENTAL DATA REQUESTS – REVENUE REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

SUPPLEMENTAL DATA REQUESTS

COST OF SERVICE

SDR-COS-1

Request:

Please explain the Company's policy with regard to when customer advances and contributions in aid of construction must be made.

Response:

An advance or contribution in aid of construction is required from an Extension Applicant or Customer when insufficient revenues will be derived from the Extension Applicant or Customer to warrant the investment by UGI Gas. Please see UGI Gas Exhibit F, Section 5, Extension Regulation, of the UGI Gas Tariff.

Prepared by or under the supervision of: Jill E. Walter

SDR-COS-2

Request:

Please provide a detailed explanation describing how contributions in aid of construction and customer advances are reflected in the Company's cost of service study.

Response:

Contributions in aid of construction, including amounts collected to cover the Company's tax obligations on certain project investments, are reflected as a deduction to rate base and included in UGI Gas Exhibit D. UGI Gas does not have any customer advances and no claim is made for customer advances.

Prepared by or under the supervision of: Amy M. Keller

SDR-COS-3

Request:

Please provide a breakdown of contributions in aid of construction by customer class and plant account number for the most recent year available.

Response:

Please see Attachment SDR-COS-3.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
CONTRIBUTIONS IN AID OF CONSTRUCTION BY CUSTOMER CLASSIFICATION AND PLANT ACCOUNT
FOR THE YEAR ENDED SEPTEMBER 30, 2025

Customer Class	Plant Account		Historic Test Year
Residential	107		$ 201,667
	376		70,913
	380		128,587
	381		259
	382		-
		Subtotal	$ 401,425
Commercial	107		$ 1,462,733
	376		307,200
	380		328,321
	381		298
	382		1,600
	385		1,600
		Subtotal	$ 2,101,752
Industrial			
	107		$ -
	376		-
	380		-
	381		-
	382		-
		Subtotal	$ -
		Total	$ 2,503,178

SDR-COS-4

Request:

Please provide a breakdown of transmission and distribution mains investment by pipe diameter.

Response:

Please see Attachment SDR-COS-4.

Prepared by or under the supervision of: John D. Taylor

UGI UTILITES, INC. - GAS DIVISION
MAINS SIZE AND ORIGINAL COSTS
ACCOUNTS 367 AND 376
AS OF SEPTEMBER 30, 2025

Account 367 - Transmission

Type	Size (Inches)	Original Cost $
Mains		
	16	$ 18,179
	14	234,989
	12.75	615,222
	12	3,415,835
	11.625	2,740
	10.75	1,803,699
	10	541,958
	9.625	26,095
	8.625	1,945,037
	8	12,517,085
	7.625	-
	7	29,545
	6.625	4,676,768
	6.25	20,665
	6	5,956,090
	5.625	15,088
	5.5625	25,555
	5.5	47,518
	5.375	19,325
	5.1875	298
	5	283,225
	4.5	540,335
	4.25	802
	4	6,001,545
	3	298,575
	2.5	6,322
	2	139,886
	1.5	42
	1.25	3,076
	1	3,021
	0.75	164
Total		$ 39,188,681
Valves		
	14	$ 10,516
	12	-
	10	17,298
	8	216,538
	6	35,149
	2	-
	1	-
		$ 279,500
Total Transmission Mains & Valves		$ 39,468,181

UGI UTILITES, INC. - GAS DIVISION
MAINS SIZE AND ORIGINAL COSTS
ACCOUNTS 367 AND 376
AS OF SEPTEMBER 30, 2025

Account 376 - Distribution

Type	Size (Inches)	Original Cost $
Mains		
	36	$ 307
	30	7,979
	24	62,535,509
	20	1,487,915
	18	221
	16	49,604,896
	14	78,202
	12	271,338,004
	10.75	33,631
	10	12,508,713
	8	385,499,535
	7	272,185
	6.625	562,482
	6.25	38,798
	6	341,889,907
	5.625	2,103
	5	318,582
	4.875	831
	4.5	34,045
	4.25	1,910
	4	549,470,333
	3.5	31,119
	3.375	1
	3	38,638,157
	2.5	39,165
	2	951,370,322
	1.5	27,896
	1.25	62,409,340
	1	4,302,108
	0.75	525,682
	0.625	1,798
	0.5	554,708
	0.25	6,376
		$ 2,733,592,761
Valves		
	24	$ 838
	16	-
	12	2,551,084
	10	495,341
	8	2,636,536
	6	4,521,508
	4	4,429,558
	3	804,015
	2.5	40
	2	5,226,488
	1.5	257
	1.25	275,405
	1	33,939
	0.75	1,901
	0.5	18,340
		$ 20,995,251
Total Distribution Mains & Valves		$ 2,754,588,011

SDR-COS-5

Request:

Please provide a breakdown of customer advances by customer class for the most recent year available.

Response:

The Company did not have any customer advances for the Fiscal Year ended September 30, 2025.

Prepared by or under the supervision of: Amy M. Keller

SDR-COS-6

Request:

Please provide a breakdown of services investment by service line diameter, and a breakdown of services by size and customer class.

Response:

Please see Attachment SDR-COS-6.

Prepared by or under the supervision of: John D. Taylor

UGI UTILITIES, INC. - GAS DIVISION
Service Size and Original Cost
Account 380
As of September 30, 2025

Service Size	R/RT	N/NT	DS	LFD	Interruptible	XD Firm	Total
10"	$ 29,666	$ 2,799	$ -	$ -	$ -	$ -	$ 32,465
8"	124,380	279,854	62,190	124,380	248,759	217,664	1,057,227
6"	178,141	870,913	415,663	554,217	277,109	98,967	2,395,009
4"	481,327	6,326,006	1,884,050	1,980,315	701,362	82,513	11,455,572
3"	415,578	3,155,318	569,496	230,877	15,392	-	4,386,661
2.5"	3,834	3,834	-	-	-	-	7,669
2"	6,482,762	27,490,271	2,848,577	1,157,422	293,853	17,991	38,290,876
1.5"	714,022	192,979	9,649	9,649	-	-	926,299
1.25"	47,808,342	17,006,804	429,180	88,095	54,212	4,518	65,391,150
1"	892,577,185	118,815,919	412,069	62,199	15,550	11,662	1,011,894,585
0.75"	44,763,489	4,276,955	19,689	1,790	4,475	895	49,067,292
0.5"	447,565,371	14,610,998	25,836	1,722	-	-	462,203,928
0.25"	622,463	40,756	-	-	-	-	663,219
Total	$ 1,441,766,561	$ 193,073,405	$ 6,676,398	$ 4,210,666	$ 1,610,711	$ 434,211	$ 1,647,771,953

SDR-COS-7

Request:

If available, please provide a breakdown of meter investment by meter size, and a breakdown of meters by size and customer class.

Response:

Please see Attachment SDR-COS-7.

Prepared by or under the supervision of: John D. Taylor

UGI UTILITIES, INC. - GAS DIVISION
METER SIZE AND ORIGINAL COST
ACCOUNT 381 and 385
AS OF SEPTEMBER 30, 2025

Meter Size	R/RT	N/NT	DS	LFD	Interruptible	XD Firm	Total
Diaphragm 1000-Series	$ 484,101	$ 25,988,724	$ 818,747	$ 74,727	$ 81,225	$ -	$ 27,447,524
Diaphragm 1400-Series	39,736	10,371,100	1,096,714	174,838	111,261	7,947	11,801,597
Diaphragm 200-Series	82,422,970	4,248,227	528	-	-	132	86,671,857
Diaphragm 2300-Series	-	2,324,623	818,822	277,567	76,331	6,939	3,504,283
Diaphragm 300-Series	953,041	441,136	223	-	-	-	1,394,399
Diaphragm 400-Series	4,565,581	5,898,724	5,236	308	616	616	10,471,081
Diaphragm 5000-Series	9,355	2,086,055	1,225,440	692,233	121,609	-	4,134,692
Diaphragm 800-Series 10Ft	700,945	2,943,968	-	-	-	-	3,644,913
Diaphragm 800-Series 2Ft	1,001,557	5,013,818	16,592	-	-	-	6,031,967
Diaphragm 800-Series 5Ft	225,740	6,776,890	136,384	9,406	-	-	7,148,420
Rotary 1.5M	-	268,825	-	-	-	-	268,825
Rotary 11C	-	134,115	8,941	-	-	-	143,057
Rotary 11M	-	935,396	968,410	1,056,447	187,079	44,019	3,191,351
Rotary 15C	-	55,052	-	-	-	-	55,052
Rotary 16M	-	875,605	477,603	1,671,610	378,102	59,700	3,462,621
Rotary 23M	-	-	6,982	27,927	13,964	-	48,873
Rotary 38M	-	97,684	-	-	-	-	97,684
Rotary 3M	3,738	3,135,889	512,058	130,818	48,589	3,738	3,834,830
Rotary 4IN-IRM3	-	-	-	-	-	31,653	31,653
Rotary 5M	-	3,143,219	1,311,787	564,005	209,125	6,337	5,234,474
Rotary 7M	-	3,082,465	1,922,211	1,229,523	225,124	86,586	6,545,909
Rotary 8C125	-	4,348	-	-	-	-	4,348
Rotary 8C175	-	27,954	-	-	-	-	27,954
Rotary ROM2000	-	-	-	-	-	-	-
Turbine 12 Inch	-	-	-	-	-	-	-
Turbine 3 Inch	-	83,847	41,924	-	20,962	-	146,733
Turbine 4 Inch	-	227,674	292,723	1,268,468	487,872	195,149	2,471,887
Turbine 6 Inch	-	365,516	166,143	963,632	996,861	531,659	3,023,811
Turbine 8 Inch	-	283,211	56,642	339,853	623,063	509,779	1,812,548
Turbine 8 Inch Auto-Adjust	-	-	-	-	-	-	-
Ultrasonic 16" Flow Meter	-	-	-	-	-	132,148	132,148
Ultrasonic 6" Flow Meter	-	-	-	-	-	-	-
Ultrasonic 800-Series	2,351,139	9,293,883	10,797	-	-	-	11,655,819
Total	$ 92,757,900	$ 88,107,949	$ 9,894,911	$ 8,481,363	$ 3,581,784	$ 1,616,403	$ 204,440,309

SDR-COS-8

Request:

Please provide the Company's rate design models and cost of service study on an IBM PC-compatible computer disk in Lotus 1-2-3 or Quattro format. If the models consist of more than one file, please include information on all files on the disk and what they contain. If not available in Lotus 1-2-3 or Quattro format, please provide in ASCII format.

Response:

Please refer to UGI Gas Exhibit D, Cost of Service Allocation, provided in electronic format and uploaded to the Commission’s SharePoint site. Those materials will be served upon the parties via a secure OneDrive link.

Prepared by or under the supervision of: John D. Taylor

SDR-COS-9

Request:

Please provide a copy of the Company's current customer extension policy. Provide a representative sample of the analyses conducted by the Company when deciding whether service to a new customer qualifies under the Company's customer extension policy.

Response:

The current customer extension policy is contained in UGI Gas Exhibit F, Rule 5, Extension Regulation, of the Company's current Tariff. Rules 5.1-5.4 and 5.7 describe the methodology to evaluate whether service to a new customer qualifies under the current extension policy and when to apply or require a contribution in aid of construction.

Prepared by or under the supervision of: Sherry A. Epler

SDR-COS-10

Request:

Please provide a detailed supply and requirement schedule for the Company's three most recent annual peak days and for design day. The schedules should include deliveries by source and requirements by rate schedule. Identify sources and requirements for transportation customers separately. Also include the Company's daily sendout sheet for each peak day and applicable weather data.

Response:

Please see Attachment SDR-COS-10.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY SENDOUT BY RATE CLASS
FOR THE YEARS ENDED SEPTEMBER 30, 2023, 2024 and 2025
(MDTH)

	2022-2023 Feb 3 (MDTH)	2023-2024 Jan 17 (MDTH)	2024-2025 Feb 18 (MDTH)
RG	3.3	2.6	2.9
RH	505.9	445.6	461.5
CG	7.4	5.0	5.8
CH	195.1	163.2	174.7
IG	1.6	2.3	2.0
IH	10.7	7.9	7.7
PGC FIRM	724.0	626.6	654.5
RT (CHOICE)	30.9	39.1	39.2
NT (CHOICE)	65.3	81.6	81.7
DS	70.8	70.0	70.9
LFD	109.3	121.3	123.8
XD-F/CDS-F	584.6	706.6	667.3
FIRM TRANSPORTATION	860.9	1018.6	982.8
INTERRUPTIBLE	64.0	60.4	57.3
TOTAL	1,648.9	1,705.6	1,694.6

UGI UTILITIES, INC. - GAS DIVISION
TEMPERATURE BY AREA
FOR THE YEARS ENDED SEPTEMBER 30, 2023, 2024 and 2025
(°F)

	2/3/2023	1/17/2024	2/18/2025
Reading/Harrisburg/Lehigh/Lancaster/Altoona	16	18	20
Wilkes-Barre/Scranton	7	17	15
Bradford	5	15	11

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2023
(DTH)

Actual For	**3-Feb-23**
System Sendout	
Daily Sendout	1,648,851
Month to Date Current Sendout	4,464,505
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	16
Wilkes-Barre/Scranton	7
Bradford	5

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2024
(DTH)

Actual For	**17-Jan-24**
System Sendout	
Daily Sendout	1,705,634
Month to Date Current Sendout	23,070,037
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	18
Wilkes-Barre/Scranton	17
Bradford	15

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2025
(DTH)

Actual For	**18-Feb-25**
System Sendout	
Daily Sendout	1,694,613
Month to Date Current Sendout	25,289,743
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	20
Wilkes-Barre/Scranton	15
Bradford	11

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY CAPACITY REQUIREMENTS AND SUPPLY OPTIONS
FOR YEAR ENDING SEPTEMBER 30, 2027
(DTH)

Supplier	Upstream Pipeline	Rate Schedule	2026-2027 (Projected)
Columbia		SST / FSS	126,473
Columbia		FTS	121,932
Columbia		NTS	19,520
Texas Eastern		FT/FT-1	182,204
Texas Eastern		CDS	84,068
Texas Eastern	EGTS	FTS-5/GSSII	6,667
Texas Eastern	EGTS	FT / GSS I	2,000
Texas Eastern	EGTS	FT / GSS II	2,000
Texas Eastern		SS-1	7,659
EGTS		FT	2,000
Texas Eastern / UGI Energy Services		Delivered Supply	40,003
Supplier B LNG Supply			10,500
Tennessee		FT	40,068
Tennessee		Delivered Supply	25,160
UGI Storage Company		NNS	8,792
Transco		FT	44,938
Transco		FTF/FT	22,770
Transco		SS-2	33,120
Transco		GSS	59,378
Transco		LGA	1,035
Transco		PS-FT	5,073
Transco		LSS	7,518
Transco		FT-Pocono	2,000
Transco Sentinel			(7,000)
Local Production - Supplier J		Direct Connection	800
Transco / UGI Energy Services		Delivered Supply	134,163
UGI Energy Services		Peaking Services	479,187
Supply TBD			30,436
Subtotal			**1,492,464**
Third Party Capacity - Large Customers			848,207
Total Firm Capacity			2,340,671

PGC-1 Requirements	963,774
CHOICE Requirements	243,984
Subtotal	**1,207,758**
Firm Transportation Requirements	**1,072,525**
Total Requirements	**2,280,283**

SDR-COS-11

Request:

Please provide copies of the Company's daily sendout sheets for November through March of the most recent heating season.

Response:

Please see Attachment SDR-COS-11.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
DAILY SENDOUT
NOVEMBER 2024 - MARCH 2025
(DTH)

Nov 2024 Sendout		Dec 2024 Sendout		Jan 2025 Sendout		Feb 2025 Sendout		Mar 2025 Sendout	
11/1/2024	755,927	12/1/2024	1,342,955	1/1/2025	1,169,303	2/1/2025	1,382,098	3/1/2025	1,237,504
11/2/2024	901,716	12/2/2024	1,356,268	1/2/2025	1,402,174	2/2/2025	1,412,385	3/2/2025	1,370,554
11/3/2024	907,987	12/3/2024	1,351,347	1/3/2025	1,434,143	2/3/2025	1,207,255	3/3/2025	1,264,415
11/4/2024	857,665	12/4/2024	1,282,725	1/4/2025	1,525,092	2/4/2025	1,334,086	3/4/2025	1,009,533
11/5/2024	731,708	12/5/2024	1,401,967	1/5/2025	1,483,402	2/5/2025	1,429,032	3/5/2025	968,621
11/6/2024	719,760	12/6/2024	1,332,316	1/6/2025	1,531,872	2/6/2025	1,350,979	3/6/2025	1,265,841
11/7/2024	776,083	12/7/2024	1,219,815	1/7/2025	1,524,460	2/7/2025	1,406,230	3/7/2025	1,111,649
11/8/2024	746,081	12/8/2024	1,054,082	1/8/2025	1,590,857	2/8/2025	1,373,445	3/8/2025	1,108,395
11/9/2024	791,532	12/9/2024	1,021,424	1/9/2025	1,551,062	2/9/2025	1,377,551	3/9/2025	1,070,438
11/10/2024	707,594	12/10/2024	944,230	1/10/2025	1,421,534	2/10/2025	1,462,556	3/10/2025	933,106
11/11/2024	627,278	12/11/2024	1,101,908	1/11/2025	1,376,871	2/11/2025	1,461,015	3/11/2025	869,645
11/12/2024	840,986	12/12/2024	1,382,917	1/12/2025	1,322,293	2/12/2025	1,385,743	3/12/2025	995,973
11/13/2024	916,585	12/13/2024	1,381,260	1/13/2025	1,412,139	2/13/2025	1,375,055	3/13/2025	1,016,819
11/14/2024	886,896	12/14/2024	1,344,849	1/14/2025	1,489,015	2/14/2025	1,416,061	3/14/2025	886,241
11/15/2024	740,786	12/15/2024	1,259,767	1/15/2025	1,527,310	2/15/2025	1,335,778	3/15/2025	809,073
11/16/2024	721,750	12/16/2024	1,135,852	1/16/2025	1,495,297	2/16/2025	1,324,080	3/16/2025	730,191
11/17/2024	739,525	12/17/2024	1,088,048	1/17/2025	1,322,804	2/17/2025	1,561,781	3/17/2025	1,060,237
11/18/2024	736,282	12/18/2024	1,089,507	1/18/2025	1,253,146	2/18/2025	1,694,613	3/18/2025	927,510
11/19/2024	744,815	12/19/2024	1,199,208	1/19/2025	1,497,799	2/19/2025	1,647,447	3/19/2025	798,953
11/20/2024	747,636	12/20/2024	1,333,814	1/20/2025	1,602,637	2/20/2025	1,680,721	3/20/2025	858,924
11/21/2024	946,900	12/21/2024	1,505,244	1/21/2025	1,693,866	2/21/2025	1,521,432	3/21/2025	954,222
11/22/2024	954,362	12/22/2024	1,566,852	1/22/2025	1,672,666	2/22/2025	1,309,326	3/22/2025	957,966
11/23/2024	713,642	12/23/2024	1,425,233	1/23/2025	1,593,290	2/23/2025	1,226,579	3/23/2025	971,294
11/24/2024	795,671	12/24/2024	1,192,418	1/24/2025	1,549,053	2/24/2025	1,135,701	3/24/2025	956,462
11/25/2024	926,027	12/25/2024	1,220,814	1/25/2025	1,429,980	2/25/2025	1,112,531	3/25/2025	936,472
11/26/2024	1,033,202	12/26/2024	1,357,355	1/26/2025	1,380,313	2/26/2025	1,043,886	3/26/2025	1,068,066
11/27/2024	997,991	12/27/2024	1,189,658	1/27/2025	1,334,614	2/27/2025	1,127,411	3/27/2025	940,547
11/28/2024	1,005,294	12/28/2024	995,879	1/28/2025	1,299,835	2/28/2025	1,008,498	3/28/2025	826,310
11/29/2024	1,191,544	12/29/2024	857,645	1/29/2025	1,307,420			3/29/2025	671,996
11/30/2024	1,290,414	12/30/2024	1,058,134	1/30/2025	1,259,990			3/30/2025	747,705
		12/31/2024	947,160	1/31/2025	1,152,126			3/31/2025	766,537

SDR-COS-12

Request:

Please provide a copy of the load duration curve used by the Company for capacity planning purposes. Please also identify the numerical data points shown for each day on the curve.

Response:

Please see Book I, Attachment 14-2, of the 2025 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2025-3054938 which can be found at https://www.puc.pa.gov/pcdocs/1877400.pdf.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-COS-13

Request:

Please provide the following for the Company's ten largest transportation customers during peak month of the most recent heating season:

a. actual consumption

b. volume delivered to the Company on their behalf, if applicable

c. daily nomination

Response:

Please see Attachment SDR-COS-13.

Prepared by or under the supervision of: Sherry A. Epler

UGI UTILITIES, INC. - GAS DIVISION
TEN LARGEST TRANSPORTATION CUSTOMERS DURING PEAK MONTH OF THE MOST RECENT HEATING SEASON
JANUARY 2025

Rate XD Customer 2	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	5,343.8	0.0
1/2/2025	7,166.4	0.0
1/3/2025	6,516.7	0.0
1/4/2025	6,548.3	0.0
1/5/2025	6,697.3	0.0
1/6/2025	7,428.2	0.0
1/7/2025	6,698.9	0.0
1/8/2025	6,919.5	0.0
1/9/2025	6,849.7	0.0
1/10/2025	6,046.2	0.0
1/11/2025	6,458.1	0.0
1/12/2025	6,606.5	0.0
1/13/2025	7,057.5	0.0
1/14/2025	6,689.0	0.0
1/15/2025	6,609.2	0.0
1/16/2025	6,748.7	0.0
1/17/2025	6,496.9	0.0
1/18/2025	5,986.2	0.0
1/19/2025	6,158.1	0.0
1/20/2025	7,290.5	0.0
1/21/2025	6,321.1	0.0
1/22/2025	6,501.3	0.0
1/23/2025	6,910.1	0.0
1/24/2025	5,720.0	0.0
1/25/2025	6,159.0	0.0
1/26/2025	6,438.3	0.0
1/27/2025	6,517.0	0.0
1/28/2025	5,826.7	0.0
1/29/2025	6,026.6	0.0
1/30/2025	5,945.7	0.0
1/31/2025	5,555.0	0.0
Total	200,236.5	0.0

Rate XD Customer 6	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	129,235.0	124,162.7
1/2/2025	154,052.5	143,948.0
1/3/2025	155,221.4	158,981.7
1/4/2025	173,844.8	176,142.4
1/5/2025	174,299.4	176,135.7
1/6/2025	145,615.1	148,505.3
1/7/2025	112,877.9	115,608.3
1/8/2025	99,861.3	101,785.4
1/9/2025	112,660.5	119,326.3
1/10/2025	111,247.7	113,577.5
1/11/2025	130,097.9	132,980.8
1/12/2025	126,457.6	130,096.2
1/13/2025	139,251.1	145,481.2
1/14/2025	119,283.2	120,376.3
1/15/2025	118,712.8	121,281.0
1/16/2025	107,888.0	112,129.9
1/17/2025	95,396.9	102,587.1
1/18/2025	119,823.8	127,592.9
1/19/2025	131,725.5	139,648.7
1/20/2025	55,948.7	59,929.7
1/21/2025	58,338.8	63,009.6
1/22/2025	72,008.4	76,507.2
1/23/2025	106,239.9	107,820.0
1/24/2025	110,583.8	117,489.9
1/25/2025	93,533.0	98,209.8
1/26/2025	112,310.2	117,422.5
1/27/2025	131,339.5	125,129.0
1/28/2025	162,137.1	154,849.9
1/29/2025	164,203.4	155,876.8
1/30/2025	150,408.0	140,452.4
1/31/2025	126,467.6	113,826.8
Total	3,801,070.8	3,840,871.0

Rate XD Customer 9	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	6,607.1	9,115.9
1/2/2025	8,715.5	8,940.3
1/3/2025	8,253.0	6,825.0
1/4/2025	7,938.2	5,706.3
1/5/2025	9,657.6	8,527.0
1/6/2025	10,255.0	13,740.7
1/7/2025	9,901.8	12,030.1
1/8/2025	10,049.6	8,321.7
1/9/2025	10,068.9	8,321.7
1/10/2025	9,366.7	8,321.7
1/11/2025	8,223.5	8,591.9
1/12/2025	9,740.9	8,591.9
1/13/2025	10,525.0	8,591.9
1/14/2025	10,375.4	8,591.9
1/15/2025	10,597.2	9,172.2
1/16/2025	10,832.5	9,172.2
1/17/2025	9,490.8	8,890.6
1/18/2025	8,293.3	4,890.1
1/19/2025	10,034.8	8,724.5
1/20/2025	10,073.5	9,927.3
1/21/2025	8,894.6	10,384.5
1/22/2025	8,627.6	10,000.8
1/23/2025	10,073.1	10,955.3
1/24/2025	9,625.6	10,000.8
1/25/2025	8,536.0	7,615.4
1/26/2025	8,815.4	5,549.7
1/27/2025	9,585.6	0.0
1/28/2025	9,585.7	0.0
1/29/2025	9,673.5	5,903.9
1/30/2025	9,709.5	4,058.7
1/31/2025	8,570.9	6,971.0
Total	290,697.8	246,435.0

Rate XD Customer 14	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	11,714.0	9,164.6
1/2/2025	12,221.0	8,927.9
1/3/2025	12,202.0	9,686.7
1/4/2025	12,071.0	14,947.2
1/5/2025	12,297.0	11,587.2
1/6/2025	12,035.0	13,406.6
1/7/2025	11,124.0	16,477.4
1/8/2025	9,739.0	12,992.3
1/9/2025	7,558.0	19,153.9
1/10/2025	11,423.0	16,848.7
1/11/2025	11,554.0	11,888.9
1/12/2025	10,142.0	11,887.9
1/13/2025	9,357.0	11,890.8
1/14/2025	8,923.0	17,043.4
1/15/2025	6,039.0	9,680.0
1/16/2025	0.0	6,013.6
1/17/2025	0.0	0.0
1/18/2025	0.0	11,401.1
1/19/2025	0.0	11,359.1
1/20/2025	0.0	6,922.4
1/21/2025	0.0	0.0
1/22/2025	0.0	0.0
1/23/2025	0.0	0.0
1/24/2025	0.0	0.0
1/25/2025	0.0	0.0
1/26/2025	0.0	0.0
1/27/2025	0.0	0.0
1/28/2025	0.0	0.0
1/29/2025	0.0	0.0
1/30/2025	0.0	0.0
1/31/2025	250.0	0.0
Total	158,649.0	231,279.7

Rate XD Customer 16	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	10,340.0	8,813.3
1/2/2025	10,310.0	10,825.5
1/3/2025	10,250.0	10,968.7
1/4/2025	10,060.0	10,612.6
1/5/2025	9,290.0	11,192.0
1/6/2025	11,080.0	9,283.9
1/7/2025	11,000.0	13,810.4
1/8/2025	11,000.0	11,883.1
1/9/2025	11,000.0	13,792.2
1/10/2025	11,000.0	11,290.4
1/11/2025	11,000.0	10,079.0
1/12/2025	11,020.0	10,368.3
1/13/2025	11,090.0	10,184.0
1/14/2025	11,500.0	12,370.0
1/15/2025	11,340.0	11,847.8
1/16/2025	10,550.0	11,623.5
1/17/2025	10,870.0	9,644.7
1/18/2025	8,440.0	11,930.9
1/19/2025	11,150.0	14,349.7
1/20/2025	10,110.0	15,229.8
1/21/2025	9,860.0	11,987.2
1/22/2025	11,010.0	11,987.2
1/23/2025	9,990.0	11,987.2
1/24/2025	11,660.0	11,987.2
1/25/2025	10,950.0	9,693.4
1/26/2025	10,890.0	9,083.5
1/27/2025	10,650.0	1,356.4
1/28/2025	10,690.0	3,724.6
1/29/2025	10,830.0	7,246.0
1/30/2025	10,660.0	5,785.5
1/31/2025	10,670.0	6,940.5
Total	330,260.0	321,878.5

Rate XD Customer 22	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	126,384.7	126,384.7
1/2/2025	130,256.8	130,256.8
1/3/2025	131,876.0	131,876.0
1/4/2025	133,411.8	133,411.8
1/5/2025	132,779.1	132,779.1
1/6/2025	133,579.5	133,579.5
1/7/2025	133,442.8	133,442.8
1/8/2025	134,100.8	134,100.8
1/9/2025	133,354.7	133,354.7
1/10/2025	132,212.2	132,212.2
1/11/2025	129,010.7	129,010.7
1/12/2025	127,579.5	127,579.5
1/13/2025	114,597.9	114,597.9
1/14/2025	122,252.9	122,252.9
1/15/2025	126,961.2	126,961.2
1/16/2025	127,648.3	127,648.3
1/17/2025	127,414.7	127,414.7
1/18/2025	120,407.9	120,407.9
1/19/2025	128,166.7	128,166.7
1/20/2025	133,619.2	133,619.2
1/21/2025	137,806.2	137,806.2
1/22/2025	138,197.7	138,197.7
1/23/2025	135,340.1	135,340.1
1/24/2025	132,541.7	132,541.7
1/25/2025	131,341.1	131,341.1
1/26/2025	130,915.7	130,915.7
1/27/2025	127,583.3	127,583.3
1/28/2025	126,068.8	126,068.8
1/29/2025	122,702.5	122,702.5
1/30/2025	126,065.9	126,065.9
1/31/2025	119,558.1	119,558.1
Total	4,007,178.5	4,007,178.5

UGI UTILITIES, INC. - GAS DIVISION
TEN LARGEST TRANSPORTATION CUSTOMERS DURING PEAK MONTH OF THE MOST RECENT HEATING SEASON
JANUARY 2025

Rate XD Customer 30	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	176,913.0	146,056.5
1/2/2025	213,513.4	194,742.0
1/3/2025	216,353.9	207,300.9
1/4/2025	217,861.9	212,849.1
1/5/2025	217,590.5	212,849.1
1/6/2025	180,294.7	203,533.6
1/7/2025	190,911.4	193,668.9
1/8/2025	207,875.4	209,298.0
1/9/2025	215,067.9	217,038.0
1/10/2025	215,295.7	218,985.4
1/11/2025	212,596.7	218,011.7
1/12/2025	212,893.8	218,011.7
1/13/2025	199,568.7	218,011.7
1/14/2025	162,729.7	218,011.7
1/15/2025	206,854.1	209,248.3
1/16/2025	210,959.8	211,245.4
1/17/2025	211,847.5	212,169.4
1/18/2025	203,318.6	204,379.7
1/19/2025	202,795.5	204,379.7
1/20/2025	206,758.7	204,379.7
1/21/2025	188,616.0	209,248.3
1/22/2025	210,442.0	210,222.0
1/23/2025	219,471.9	218,011.7
1/24/2025	217,772.6	214,116.8
1/25/2025	216,841.1	219,082.8
1/26/2025	217,370.3	219,082.8
1/27/2025	185,218.5	189,871.5
1/28/2025	142,506.0	141,187.9
1/29/2025	140,792.1	138,266.8
1/30/2025	138,468.3	138,266.8
1/31/2025	138,844.5	138,266.8
Total	6,098,344.2	6,169,794.7

Rate XD Customer 47	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	27,656.0	39,480.5
1/2/2025	29,504.0	33,280.7
1/3/2025	30,462.0	32,780.7
1/4/2025	31,375.0	35,278.8
1/5/2025	31,414.0	34,279.7
1/6/2025	31,866.0	31,682.3
1/7/2025	32,876.0	45,868.4
1/8/2025	34,332.0	48,365.5
1/9/2025	33,685.0	44,369.4
1/10/2025	35,121.0	43,770.0
1/11/2025	35,753.0	43,271.0
1/12/2025	36,523.0	42,771.0
1/13/2025	37,394.0	41,272.9
1/14/2025	37,603.0	41,272.9
1/15/2025	37,632.0	40,373.3
1/16/2025	37,890.0	41,372.3
1/17/2025	38,119.0	41,372.3
1/18/2025	38,722.0	40,573.1
1/19/2025	38,792.0	39,374.3
1/20/2025	39,056.0	41,272.9
1/21/2025	39,241.0	41,284.6
1/22/2025	39,859.0	41,272.9
1/23/2025	40,397.0	41,771.9
1/24/2025	40,414.0	39,274.9
1/25/2025	40,501.0	40,273.9
1/26/2025	41,733.0	38,774.9
1/27/2025	41,911.0	38,275.8
1/28/2025	42,652.0	31,369.4
1/29/2025	43,865.0	34,578.9
1/30/2025	45,000.0	34,578.9
1/31/2025	45,000.0	36,677.4
Total	1,156,348.0	1,220,215.5

Rate XD Customer 50	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	0.5	0.0
1/2/2025	2,239.4	1,930.4
1/3/2025	3.4	0.0
1/4/2025	5,591.4	4,796.0
1/5/2025	4,487.8	4,796.0
1/6/2025	6,024.9	4,796.0
1/7/2025	4,737.4	4,796.0
1/8/2025	5,298.4	4,796.0
1/9/2025	0.6	0.0
1/10/2025	4,265.7	6,552.6
1/11/2025	0.0	2,397.5
1/12/2025	0.6	2,397.5
1/13/2025	5,030.6	2,397.5
1/14/2025	3,446.0	2,877.2
1/15/2025	6,018.9	2,877.2
1/16/2025	0.0	0.0
1/17/2025	0.6	2,383.0
1/18/2025	5,482.8	7,721.5
1/19/2025	22,161.9	20,268.9
1/20/2025	18,472.0	20,268.9
1/21/2025	22,053.0	20,268.9
1/22/2025	24,419.4	19,288.2
1/23/2025	438.0	0.0
1/24/2025	0.0	0.0
1/25/2025	5,429.0	4,796.0
1/26/2025	5,360.0	4,796.0
1/27/2025	9,907.4	9,621.9
1/28/2025	3,806.2	5,754.4
1/29/2025	12,074.2	9,591.0
1/30/2025	9,510.5	6,726.4
1/31/2025	2,896.6	959.4
Total	189,157.2	177,854.4

Rate XD Customer 54	(a.) Actual Consumption (Mcf)	(b. and c.) Volume Delivered / Daily Nomination (Mcf)
1/1/2025	4,543.0	4,500.0
1/2/2025	4,594.0	4,500.0
1/3/2025	4,621.0	4,500.0
1/4/2025	4,624.0	4,500.0
1/5/2025	4,705.0	4,596.7
1/6/2025	4,675.0	4,596.7
1/7/2025	4,577.0	4,838.5
1/8/2025	4,559.0	4,838.5
1/9/2025	4,629.0	4,838.5
1/10/2025	4,525.0	4,838.5
1/11/2025	4,521.0	4,693.4
1/12/2025	4,540.0	4,693.4
1/13/2025	4,487.0	4,693.4
1/14/2025	3,183.0	4,693.4
1/15/2025	2,865.0	4,693.4
1/16/2025	3,689.0	4,693.4
1/17/2025	3,962.0	4,500.0
1/18/2025	3,910.0	4,751.5
1/19/2025	3,929.0	4,751.5
1/20/2025	3,763.0	4,751.5
1/21/2025	3,729.0	4,751.5
1/22/2025	3,874.0	4,751.5
1/23/2025	4,050.0	4,500.0
1/24/2025	4,251.0	4,500.0
1/25/2025	4,594.0	4,354.9
1/26/2025	4,513.0	4,354.9
1/27/2025	4,513.0	4,354.9
1/28/2025	4,458.0	4,354.9
1/29/2025	4,498.0	4,354.9
1/30/2025	4,692.0	4,354.9
1/31/2025	4,682.0	4,354.9
Total	132,755.0	142,449.6

SDR-COS-14

Request:

Please provide a summary identifying the salient features of each of the following. Salient features include contract party, effective term and applicable contract quantities (daily, annual, seasonal, etc.).

a. All firm transportation agreements by type greater than one month in length. Indicate whether the capacity is available at the Company's citygate to meet design day requirements or is upstream capacity. Identify the downstream pipeline for each upstream arrangement.

b. All firm storage, gathering and exchange agreements. Indicate if each agreement provides design day capacity at the citygate or requires separate transportation (identify) service to effectuate delivery. Include on-system storage and peak shaving facilities used by the Company and identify all ratcheting provisions applicable to the Company's contractual and on-system storage arrangements.

Response:

Please see Attachments SDR-COS-14(a) and SDR-COS-14(b) included in print and uploaded to the Commission’s SharePoint site. Those materials will be served upon the parties via a secure OneDrive link. The contracts are reflected as of November 1, 2025.

Prepared by or under the supervision of: Tracy A. Hazenstab

Pipeline	Rate Schedule	Contract ID	Contract Type	Term Start	Term End	MDQ	SCQ	Capacity Flow	Downstream Pipe
Columbia	FSS	79028	Storage	11/1/2004	3/31/2030	126,473	7,050,541	Upstream	Columbia
Columbia	FTS	46284	Transport	11/1/1993	10/31/2028	50,412		City Gate	
Columbia	FTS	78653	Transport	5/15/2004	10/31/2029	42,000		City Gate	
Columbia	FTS	80021	Transport	11/1/2004	10/31/2030	21,500		City Gate	
Columbia	FTS	80095	Transport	11/1/2004	3/31/2029	18,020		City Gate	
Columbia	FTS	80835	Transport	11/1/2004	10/31/2028	3,738		City Gate	
Columbia	NTS	80837	Transport	11/1/2004	10/31/2029	15,000		City Gate	
Columbia	SST	79133	Transport	11/1/2004	3/31/2030	126,473		City Gate	
Columbia	FTS	229154	Transport	11/1/2004	3/31/2030	7,750		City Gate	
Columbia	FTS	230222	Transport	11/1/2012	10/31/2027	10,782		City Gate	
Columbia	NTS	230215	Transport	11/1/2012	3/31/2029	4,520		City Gate	
Columbia	FTS	230211	Transport	11/1/2004	10/31/2027	2,432		City Gate	
Columbia	FTS	230212	Transport	11/1/2019	10/31/2027	2,432		City Gate	
Columbia	FTS	230213	Transport	11/1/2019	10/31/2027	2,432		City Gate	
Columbia	FTS	230214	Transport	11/1/2019	10/31/2027	2,434		City Gate	
EGTS	FT	200796	Transport	1/1/2005	3/31/2028	2,000		City Gate	
EGTS	FT	700117	Transport	11/1/1998	3/31/2030	2,000		Upstream	TETCO
EGTS	FTGSS	700121	Transport	11/1/2024	3/31/2045	56,667		Upstream	EGTS
EGTS	GSS	300225	Storage	11/1/1998	3/31/2030	2,000	200,000	Upstream	TETCO
EGTS	GSS	300126	Storage	11/1/1998	3/31/2030	8,667	866,667	Upstream	TETCO
EGTS	GSS	300234	Storage	4/1/2024	3/31/2045	56,667	3,400,000	Upstream	Tennessee/TETCO
Tennessee	FT-G	62498	Transport	9/1/1993	10/31/2030	Variable - 400 dth/d to 1,200 dth/d		City Gate	
Tennessee	FT-G	62499	Transport	9/1/1993	10/31/2030	Variable - 0 dth/d to 2,054 dth/d		City Gate	
Tennessee	FT-A	301692	Transport	11/1/2014	10/31/2029	34,000		City Gate	
Tennessee	FT-A	362539	Transport	11/1/2020	10/31/2026	3,183		City Gate	
TETCO	CDS	800239	Transport	6/1/1993	10/31/2026	25,000		City Gate	
TETCO	CDS	800397	Transport	11/1/1993	10/31/2026	41,000		City Gate	
TETCO	CDS	820019	Transport	11/1/2000	10/31/2026	10,000		City Gate	
TETCO	Flex-X	800504	Transport	11/1/1995	10/31/2026	4,000		City Gate	
TETCO	FT-1	800240	Transport	6/1/1993	10/31/2026	25,000		City Gate	
TETCO	FT-1	800373	Transport	11/1/1994	10/31/2027	20,000		City Gate	
TETCO	FT-1	800394	Transport	11/1/1993	10/31/2026	32,475		City Gate	
TETCO	FT-1	800468	Transport	11/1/1995	10/31/2027	10,000		City Gate	
TETCO	FT-1	830067	Transport	12/1/1999	10/31/2027	10,000		City Gate	
TETCO	FT-1	910181	Transport	11/1/2004	10/31/2026	12,000		City Gate	
TETCO	FT-1	910417	Transport	11/1/2003	10/31/2026	11,713		City Gate	
TETCO	FTS-5	330910	Transport	6/1/1993	3/31/2028	6,667		City Gate	
TETCO	FT-1	911580	Transport	11/1/1994	4/15/2027	5,880		City Gate	
TETCO	CDS	800376	Transport	10/1/1993	10/31/2027	8,068		City Gate	
TETCO	FT-1	800404	Transport	11/1/1994	10/31/2026	1,136		City Gate	
TETCO	FT-1	830060	Transport	3/24/1999	11/30/2027	4,000		City Gate	
TETCO	FT-1	911777	Transport	11/1/2021	10/31/2036	18,000		City Gate	
TETCO	FT-1	911153	Transport	11/1/2014	10/31/2026	3,300		Upstream	Columbia
TETCO	FT-1	911966	Transport	11/1/2024	10/31/2036	32,000		City Gate	
TETCO	FT-1	8983450	Transport	4/1/2020	3/31/2026	15,003		City Gate	
TETCO	SS-1	400190	Storage	5/1/1994	4/30/2027	7,659	541,911	City Gate	
Transco	FT	1005004	Transport	8/1/1991	3/31/2029	1,346		City Gate	
Transco	FT	1002594	Transport	2/1/1992	3/31/2029	5,072		City Gate	
Transco	FT	1002595	Transport	4/10/1990	3/31/2029	2,081		City Gate	
Transco	FT	1013596	Transport	10/1/1996	3/31/2027	22,770		City Gate	
Transco	FT	9089608	Transport	11/1/2009	10/31/2029	7,000		City Gate	
Transco	FT	9180223	Transport	12/1/2015	7/31/2028	12,279		City Gate	
Transco	FT-PS	1004999	Transport	8/1/1991	3/31/2029	3,416		City Gate	
Transco	FT-Pocono	1021106	Transport	11/1/1997	10/31/2027	500		City Gate	
Transco	FT	1003692	Transport	2/1/1992	3/31/2029	8,328		City Gate	
Transco	FT-PS	1005005	Transport	8/1/1991	7/31/2028	311		City Gate	
Transco	FT	1006503	Transport	10/1/1993	10/31/2026	4,566		City Gate	
Transco	FT	1012119	Transport	11/16/1995	3/31/2027	828		City Gate	
Transco	FT-Pocono	1021107	Transport	11/1/1997	3/31/2027	1,500		City Gate	
Transco	FT-LS	9250893	Transport	10/19/2021	11/30/2036	2,400		City Gate	
Transco	GSS	1000798	Storage	7/1/1996	3/31/2028	56,532	2,746,576	City Gate	
Transco	LSS	1000796	Storage	10/1/1993	3/31/2027	7,518	827,053	City Gate	
Transco	SS-2	1004032	Storage	4/1/1990	3/31/2028	25,875	2,846,250	City Gate	
Transco	ESS	9162496	Storage	11/1/1993	10/31/2026	10,000	83,847	Upstream	Transco
Transco	GSS	1000749	Storage	7/1/1996	3/31/2028	1,744	102,129	City Gate	
Transco	SS2	1003973	Storage	7/25/1990	3/31/2028	7,245	796,950	City Gate	
Transco	GSS	1000780	Storage	7/1/1996	3/31/2028	1,102	57,881	City Gate	

Pipeline	Rate Schedule	Contract ID	Contract Type	Term Start	Term End	MDQ	SCQ	Capacity Flow	Downstream Pipe
Transco	LG-A	1000783	Storage	11/1/1974	3/31/2026	1,035	4,140	City Gate	
Transco	FT	9305460	Transport	11/1/2025	10/31/2037	25,254		City Gate	
UGI Storage Company	NNS	NNS-1	Transport	4/1/2011	3/31/2027	8,792		City Gate	
UGI Storage Company	FSS	FSS-1	Storage	4/1/2011	3/31/2027	8,792	879,200	City Gate	
Supplier A		N/A	Delivered Supply	12/1/2025	3/31/2030	500		City Gate	
Supplier B		N/A	Delivered Supply	12/1/2024	3/31/2027	10,000		City Gate	
Supplier C		N/A	Delivered Supply	11/1/2014	3/31/2026	800		City Gate	
Supplier D		N/A	Delivered Supply	11/1/2018	10/31/2028	16,766		City Gate	
Supplier D		N/A	Delivered Supply	11/1/2024	3/31/2029	8,394		City Gate	
Supplier E		N/A	Delivered Supply	11/1/2019	7/30/2030	200			
Supplier F		N/A	Delivered Supply	5/13/2022	4/30/2027	909			
UGI Energy Services		UGI-CO-1014	Delivered Supply	11/1/2021	10/31/2036	25,000		City Gate	
UGI Energy Services		UGIN-CO-1012	Delivered Supply	11/1/2018	10/31/2033	36,169		City Gate	
UGI Energy Services		UGI-CO-1013	Delivered Supply	11/1/2020	10/31/2038	97,994		City Gate	
UGI Energy Services		UGIN-CO-1017	Delivered Supply	11/1/2025	3/31/2026	17,963		City Gate	
UGI Energy Services		UGI-CO-1018	Delivered Supply	4/1/2026	3/31/2030	15,003		City Gate	
UGI Energy Services		UGIU-P-1010	Peaking	11/1/2015	3/31/2030	106,465		City Gate	
UGI Energy Services		UGIU-P-1012	Peaking	11/1/2016	3/31/2031	23,632		City Gate	
UGI Energy Services		UGIU-P-1014	Peaking	11/1/2018	3/31/2033	40,573		City Gate	
UGI Energy Services		UGIU-P-1016	Peaking	11/1/2021	3/31/2036	162,177		City Gate	
UGI Energy Services		UGIU-P-1017	Peaking	11/1/2021	3/31/2036	72,299		City Gate	
UGI Energy Services		UGIU-P-1020	Peaking	12/1/2024	3/31/2039	40,000		City Gate	
UGI Energy Services		CPG-P-1006	Peaking	11/1/2015	3/31/2030	4,750		City Gate	
UGI Energy Services		CPG-P-1007	Peaking	11/1/2018	3/31/2033	5,000		City Gate	
UGI Energy Services		CPG-P-1008	Peaking	11/1/2018	3/31/2033	2,519		City Gate	
UGI Energy Services		PNG-P-1003	Peaking	11/1/2016	3/31/2031	21,772		City Gate	

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
COLUMBIA	**FSS**	7,050,541	63,706	MDIQ = 1/25 of monthly maximum and	YEAR	126,473	39	MDWQ =100% if % if gas in storage is >30%	56	YEAR	
	79028			Nov and Dec = 1/30 of monthly maximum	ROUND	101,178	6	80% MDWQ if gas in storage is <30% and >20%		ROUND	sec.4/ p.84-86
				MAXIMUM MONTHLY INJECTIONS -		82,207	8	65% MDWQ if gas in storage is <20% and >10%			
				Apr=15%; May thru July = 20%;		63,237	11	50% MDWQ if gas in storage is <10% and >0%			
				August= 18%: Sept = 13%; Oct=9%; Nov=5%;		9,458	1	last withdrawal to empty field			
				Dec thru Mar= 10%		Total	65	MAXIMUM MONTHLY WITHDRAWALS -			
								NOV DEC JAN - 40% OF SCQ			
								FEB - 30% OF SCQ			
	INJ RULES:	1) Subject to minimum and maximum daily and monthly injection limits.						MAR - 20% OF SCQ			sec.4/ p.86
		2) Excess must be requested 24hrs in advance						MINIMUM MONTHLY WITHDRAWALS -			sec.4/ p.87
	WDL RULES:	1) Subject to minimum and maximum daily and monthly withdrawals limits						FEB - 10% OF SCQ			sec.4/ p.88
		2) Excess must be requested 24hrs in advance						MAR - 10% OF SCQ			sec.4/ p.88
	Seasonal Rules	1) Subject to seasonal maximum inventory levels: no more than 60% of SCQ on 6/30 and no more than 85% of SCQ on 8/31									sec.4/ p.87
		2) Subject to seasonal maximum inventory levels: no more than 25% of SCQ on 4/1 and no more than 65% of SCQ on 2/1									sec.4/ p.89
	Overrun	1) DAILY PENALTY based on the price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia" as									sec.4/ p.91
		published in Platts Gas Daily price survey for all quantities taken in excess of its Lowered Quantity									
		2) DAILY OFO PENALTY based on the price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia"									sec.4/ p.91
		as published in Platts Gas Daily price survey shall be assessed to Shipper for all quantities in violation of that operational flow order									
		3) DAILY PENALTY = If injections exceed 110% of MDIQ, charge is $5 for all dth in excess of MDIQ									
		4) MONTHLY PENALTY = If injections exceed 105% of MMIQ, charge is $5 for all dth in excess of 105%									sec.4/ p.91
		5) MONTHLY PENALTY = If withdrawls exceed monthly limits, charge is $5 for all dth in excess of limits									sec.4/ p.92
		6) DAILY PENALTY = If injections or withdrawals exceed SCQ or results in a negative balance, charge is $5 for all dth in excess ofSCQ									sec.4/ p.92
		7) DAILY PENALTY = If unauthorized withdrawals > 103% of MDWQ, charge is $10 for all dth can be reduced if paying matching transportation penalties									
		8) Gas is forfeited to Pipeline if :a) OFO violation; b) failure to withdrawal monthly minimum; c)Failure to comply with April 1 limit									sec.4/ p.92

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
EGTS	**GSS**	866,667	4,815	SUMMER : if storage balance < or = 1/2	YEAR	8,667	65	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300126		4,050	of capacity then 1/180 of capacity;	ROUND	7,974	21	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		6,067	9	70% MDWQ if % if gas in storage is <16% and >10%			
	(VIA FTS-5)			then 1/214 of capacity		5,460	14	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity		3695	1	last withdrawal to empty field			
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;				**Total**	**110**				
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to exess charge									p.58/sec. 7.4
	WDL RULES:	1) Monthly limit : EGTS is required to deliver only 87.5% in any month									p. 60/sec. 8.6
		2) Excess withdrawals may be requested, subject to excess charge									p. 61/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceeding year									p. 60/sec. 8.7
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									p. 60/sec. 8.5
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									p. 27
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									p. 27
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									p. 27
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
EGTS	**GSS-III**	3,400,000	18,889	SUMMER : if storage balance < or = 1/2	YEAR	56,667	65	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300234		15,888	of capacity then 1/180 of capacity;	ROUND	52,134	21	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		39,667	9	70% MDWQ if % if gas in storage is <16% and >10%			
				then 1/214 of capacity		35,700	16	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity		Total	111	last withdrawal to empty field			
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;									
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to excess charge									p.58/sec. 7.4
	WDL RULES:	1) Monthly limit : EGTS is required to deliver only 70.0% in any month									p. 60/sec. 8.6
		2) Excess withdrawals may be requested, subject to excess charge									p. 61/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									p. 60/sec. 8.7
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									p. 60/sec. 8.5
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									p. 27
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									p. 27
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									p. 27
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
EGTS	**GSS**	200,000	1,111	SUMMER : if storage balance < or = 1/2	YEAR	2,000	65	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300225		935	of capacity then 1/180 of capacity;	ROUND	1,840	21	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		1,400	9	70% MDWQ if % if gas in storage is <16% and >10%			
				then 1/214 of capacity		1,260	16	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity		Total	111	last withdrawal to empty field			
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;									
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to excess charge									p.58/sec. 7.4
	WDL RULES:	1) Monthly limit : EGTS is required to deliver only 87.5% in any month									p. 60/sec. 8.6
		2) Excess withdrawals may be requested, subject to excess charge									p. 61/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									p. 60/sec. 8.7
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									p. 60/sec. 8.5
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									p. 27
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									p. 27
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									p. 27
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS (Based on Top Inventory)	Contractual Number of Days	W/D SEASON	Tariff Reference
UGI STORAGE Co.	**FSS**	879,200	4,885	0 -50% of Storage Cap Quantity	YEAR	8,792	48	100% MDWQ if % if gas in storage is >50%	100	YEAR	sec 6.0.2.1
			4,103	50-100% of Storage Cap Quantity - 84% of MDIQ	ROUND	6,594	47	75% MDWQ if % if Inventory is 15% to 50%		ROUND	sec 9.2
						3,956	34	45% MDWQ if % is 0% to 15%			
						Total	129				

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TETCO	**SS-1**	541,911	2,785		YEAR	7,659	48	> 174,300 but <= 541,911	71	YEAR	
	400190				ROUND	6,762	7	> 125,601 but <= 174300		ROUND	
						5,707	9	> 73,101 but <=125,600			
						1,516	27	>32,601 but <= 73,100			
						929	35	<= 32,600			
						Total	126				
	INJ RULES:	1) Excess injections may be requested, subject to charge									
	WDL RULES:	1) Excess withdraws may be requested, subject to charge									
	Seasonal Rules	1) No-notice service that cannot exceed MSQ; No carryover provisions									
		2) If, at any time the MSQ is <10% of aggregate customers MSQ, then for remaining year any injs or transfers will not be included in determining the ratchet									
		3) MMWQ subject to Texas Eastern's operational availability, per annual notice.									
	Overrun	1) MONTHLY PENALTIES :Charge for excess injections/withdrawals is maximum (p.87 of tariff) times dth in excess									sec. 3.2
		2) Subject to cashout									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**GSS**	102,129	567	0 -50% of Storage Cap Quantitiy =1/180	YEAR	1744	38	MDWQ =100% if % if gas in storage is >35%	59	YEAR	
	1000749		477	50-100% of Storage Cap Quantitiy =1/214	ROUND	1,727	9	99% of MDWQ if % if gas in storage is 20% to 35%		ROUND	
						1,291	10	74% of MDWQ if % if gas in storage is 7% to 20%			
						959	7	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule				374	1	last withdrawal to empty field			
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period				Total	65				sec 8.3b/p 336
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 8.3c/p 336
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 8.3c/p 336
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by Apr 15									sec 8.3d/p 336-337
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 8.3e/p 336
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceeding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**SS-2**	796,950	5,313	0 -10% of Storage Cap Quantitiy =1/150	4/1-10/31	7,245	77	>30 -100% of Annual Storage Volume in balance =1/110	110	11/1-3/31	
	1003973		4,981	>10-30% of Storage Cap Quantitiy =1/160		6,641	18	>15 -30% of Annual Storage Volume in balance =1/120			
			4,554	>30-50% of Storage Cap Quantitiy =1/175		5,903	7	>10 -15% of Annual Storage Volume in balance =1/135			
			4,308	>50-70% of Storage Cap Quantitiy =1/185		5,313	14	<10% of Annual Storage Volume in balance =1/150			
			3,985	>70-100% of Storage Cap Quantitiy =1/200		3,844	1	last withdrawal to empty field			
	INJ RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C				Total	117				GT&C sec.18.1
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									GT&C sec.18.1
	Seasonal Rules										

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**GSS**	2,746,576	15,259	0 -50% of Storage Cap Quantity =1/180	YEAR	56,532	**31**	MDWQ =100% if % if gas in storage is >35%	49	1/1-12/31	
	1000798		12,834	50-100% of Storage Cap Quantity =1/214	ROUND	55,967	**7**	99% of MDWQ if % if gas in storage is 20% to 35%			
						41,834	**9**	74% of MDWQ if % if gas in storage is 7% to 20%			
						31,093	**7**	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule				Total	**54**	last withdrawal to empty field			
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period									sec 8.3b/p 336
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 8.3c/p 336
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 8.3c/p 336
	Seasonal Rules	1) Minimum turnover is the difference between 35% of storage capacity and prior November 1 balance by Apr 15 (Does not include injection during winter period)									sec 8.3d/p 336-337
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 8.3e/p 336
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**SS-2**	2,846,250	18,975	0 -10% of Storage Cap Quantity =1/150	4/1-10/31	25,875	**77**	>30 -100% of Annual Storage Volume in balance =1/110	110	11/1-3/31	
	1004032		17,789	>10-30% of Storage Cap Quantity =1/160		23,719	**18**	>15 -30% of Annual Storage Volume in balance =1/120			
			16,264	>30-50% of Storage Cap Quantity =1/175		21,083	**7**	>10 -15% of Annual Storage Volume in balance =1/135			
			15,385	>50-70% of Storage Cap Quantity =1/185		18,975	**15**	<10% of Annual Storage Volume in balance =1/150			
			14,231	>70-100% of Storage Cap Quantity =1/200		Total	**117**				
	INJ RULES:										GT&C sec.18.1
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									GT&C sec.18.1
	Seasonal Rules	1) Swing rate ability, subject to Sec. 18.1 of GT&C									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**LSS**	827,053	4,595	0 -50% of Storage Cap Quantity =1/180	4/1-10/31	7,518	**71**	MDWQ =100% if % if gas in storage is >35%	110	11/1-3/31	
	1000796		3,865	50-100% of Storage Cap Quantity =1/214		7,142	**5**	95% of MDWQ if % if gas in storage is >=30% and < 35%			
						5,639	**21**	75% of MDWQ if % if gas in storage is >=16% < 30%			
						5,037	**10**	67% of MDWQ if % if gas in storage is >=10% and < 16%			
						3,759	**22**	50% of MDWQ if % if gas in storage is >0% and < 10%			
						Total	**129**				
	INJ RULES:										
	WDL RULES:	1) Transco is required to deliver only 92% in any consecutive 30 day period									sec 8.3b/p. 349
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by March 31									
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 6.67%									sec 8.3c/p. 349
		1) Minimum turnover is the difference between 35% of storage capacity and prior November 1 balance by Apr 1									sec 8.3d/p. 349
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									sec 8.3d/p. 349
		4) Subject to specific buyer OFO's to allow Transco manage LSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**GSS**	57,881	322	0 -50% of Storage Cap Quantity =1/180	YEAR	1,102	**34**	MDWQ =100% if % if gas in storage is >35%	53	YEAR	sec. 7.3a
	1000780		270	50-100% of Storage Cap Quantity =1/214	ROUND	1,091	**8**	99% of MDWQ if % if gas in storage is 20% to 35%		ROUND	
						815	**9**	74% of MDWQ if % if gas in storage is 7% to 20%			
						606	**7**	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule				Total	**58**				
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period									sec 8.3b/p 336
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 8.3c/p 336
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 8.3c/p 336
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by Apr 15									sec 8.3d/p 336-337
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 8.3e/p 336
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**LGA 1000783**	4,140	21	Returns = 1/200 of Liquefaction Capacity Quantity	4/1-10/31	1,035	4	NOT RATCHETED	4	11/1-3/31	sec. 7.3a
	INJ RULES:	1) Injections during withdrawal period may be requested									sec 7.4/p. 372
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									sec 7.1b/p. 371
		2) Excess withdrawals may be requested, subject to excess delivery charge									sec 7.3c/p. 371
		3) Withdrawals during Oct and Apr may be requested									sec 11/p. 373
	Seasonal Rules	1) Cumulative delivery nominations during withdrawal period will not exceed beginning Gas Balance									sec 10/p. 373

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**ESS 1006655**	83,847	838		YEAR ROUND	10,000	9		9	YEAR ROUND	
	INJ RULES:	Subject to Transco's operating conditions in the Eminence field and system conditions at the time									sec 5.2/p. 299
	WDL RULES:	Subject to Transco's operating conditions in the Eminence field and system conditions at the time									sec 6.2/p. 300
	Seasonal Rules										

SDR-COS-15

Request:

For the most recent annual period available, please identify the applicable monthly volumes and revenues under each rate schedule which were:

a. Sold under a negotiated or market-based rate

b. Transported under a negotiated or market based rate

c. Transported at full margin transportation rates

Response:

Please see Attachment SDR-COS-15.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Sales and Revenues for Selected Rate Schedules

a.	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Sales (Mcf)												
None	-	-	-	-	-	-	-	-	-	-	-	-
Revenue ($)												
None	-	-	-	-	-	-	-	-	-	-	-	-
b.												
Sales (Mcf)												
Rate IS	1,162,565	1,093,843	1,187,624	1,049,100	1,059,444	1,020,139	1,054,880	971,573	771,828	764,242	873,115	824,152
Rate XD	13,378,358	13,170,149	17,131,780	18,626,256	17,107,927	15,624,520	17,587,417	17,277,279	17,243,298	16,990,037	16,964,340	13,821,543
Revenue ($)												
Rate IS	$ 2,070,764	$ 1,925,006	$ 2,213,855	$ 6,007,016	$ 1,864,840	$ 1,964,172	$ 1,884,997	$ 1,580,457	$ 1,612,288	$ 1,491,141	$ 1,539,866	$ 1,607,509
Rate XD	$ 3,773,416	$ 3,560,188	$ 3,756,317	$ 5,188,730	$ 2,802,034	$ 3,222,254	$ 3,633,718	$ 3,278,626	$ 3,171,491	$ 4,717,997	$ 1,977,096	$ 3,335,170
c.												
Sales (Mcf)												
Rate RT	267,942	561,424	1,105,344	1,445,997	1,135,551	688,232	413,686	184,265	113,071	105,445	111,643	98,426
Rate NT	676,560	1,270,028	2,313,396	2,986,532	2,364,870	1,471,751	1,062,270	558,708	473,332	418,837	426,543	414,527
Rate DS	542,765	836,202	1,384,773	1,721,890	1,384,835	966,359	678,372	418,158	299,653	286,255	308,819	320,651
Rate LFD	2,077,742	2,122,770	2,658,827	3,098,345	2,471,724	2,328,871	2,010,952	1,719,690	1,553,094	1,513,499	1,577,900	1,620,864
Revenue ($)												
Rate RT	$ 3,184,223	$ 5,251,095	$ 7,718,899	$ 9,552,234	$ 8,211,105	$ 6,575,923	$ 3,978,585	$ 2,610,008	$ 2,094,661	$ 2,038,381	$ 2,148,292	$ 1,985,895
Rate NT	$ 3,756,892	$ 6,483,987	$ 9,508,659	$ 11,835,679	$ 10,107,635	$ 7,836,683	$ 5,071,107	$ 3,079,243	$ 2,628,578	$ 2,412,138	$ 2,452,563	$ 2,376,223
Rate DS	$ 3,806,262	$ 4,652,172	$ 6,433,609	$ 7,677,149	$ 6,365,284	$ 3,657,448	$ 2,896,982	$ 3,119,238	$ 3,050,335	$ 2,937,542	$ 2,845,424	$ 3,018,570
Rate LFD	$ 5,637,074	$ 5,268,565	$ 6,423,550	$ 11,345,983	$ 6,176,723	$ 5,356,751	$ 4,481,196	$ 4,533,906	$ 4,126,014	$ 4,518,860	$ 5,137,163	$ 4,826,329

SDR-COS-16

Request:

Please provide the following for each curtailment during the last three years:

a. Dates of curtailment

b. Type of curtailment (firm service, interruptible service, both)

c. Whether curtailment was related to amount of capacity on the Company's system, other capacity or supply related

d. Rate schedule that curtailed volumes would have been billed under

e. Curtailed volumes by rate schedule

f. Actual volumes moved by rate schedule

Response:

The Company has had no curtailments of firm service during the last three years.

Prepared by or under the supervision of: Jill E. Walter

SDR-COS-17

Request:

Please identify the Company's design day planning criteria and the probability of design day occurrence. Include any available documentation supporting the Company's claimed probability of occurrence.

Response:

Please see Book I, Section 11 of the 2025 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2025-3054938 which can be found at https://www.puc.pa.gov/pcdocs/1877400.pdf.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-COS-18

Request:

For each customer class contained in the cost of service study, please provide monthly throughput by class.

Response:

Please see Attachment SDR-COS-18.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Sales by Cost of Service Study Classification (Mcf's)

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL 2027
Service Classification:													
Rate R/RT	2,353,068	5,417,825	8,182,235	9,721,934	8,285,451	7,279,778	3,606,088	1,851,176	1,218,775	807,594	841,881	925,231	50,491,037
Rate N/NT	1,476,735	2,980,471	4,593,424	5,584,465	4,807,335	4,144,442	2,114,635	1,167,736	880,065	710,242	759,691	788,795	30,008,036
Rate DS	469,348	790,717	1,230,574	1,587,588	1,420,826	1,178,881	683,326	413,133	291,148	247,847	253,793	300,860	8,868,042
Rate LFD	2,178,226	2,439,512	2,722,453	2,938,512	2,626,143	2,543,149	2,211,337	2,050,030	1,899,805	1,876,792	1,910,642	1,945,350	27,341,950
Rate XD Firm	17,561,353	17,103,536	17,210,521	17,440,940	17,224,597	17,353,349	16,765,507	17,514,952	16,562,698	17,763,196	17,696,800	17,629,165	207,826,615
Rate Interruptible	1,184,500	1,247,668	1,309,336	1,427,457	1,287,549	1,321,337	1,252,480	1,189,795	1,112,569	1,111,320	1,112,666	1,111,874	14,668,550
Total	25,223,230	29,979,729	35,248,544	38,700,895	35,651,900	33,820,936	26,633,373	24,186,823	21,965,062	22,516,991	22,575,474	22,701,275	339,204,231

SDR-COS-19

Request:

Please provide workpapers showing the development of each allocation factor reflected in the Company's cost of service study. Include a description of each allocation factor, all calculations performed to develop the allocators and all supporting documentation, studies or other information relied upon to determine the allocators.

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: John D. Taylor

SDR-COS-20

Request:

Please provide all workpapers, calculations and supporting documentation for the functionalization and classification performed for the Company's cost of service study.

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: John D. Taylor

SDR-COS-21

Request:

If not provided elsewhere, please provide a detailed proof of revenues at both present and proposed rates.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue.

Prepared by or under the supervision of: Sherry A. Epler

SUPPLEMENTAL DATA REQUESTS

RATE OF RETURN

SDR-ROR-1

Request:

Please supply copies of the following documents for the Company and, if applicable, its parent:

a. Most recent Annual Report to shareholders (including any statistical supplements);

b. Most recent SEC Form l0K,

c. All SEC Form l0Q reports issued within last year.

Response:

a. Please refer to the UGI Corporation website for the most recent UGI Corporation Annual Report to shareholders at the following link: https://www.ugicorp.com/investors/financial-reports/annual-reports

b. Please refer to the response to request II-A-3 for the UGI Corporation SEC Form 10-K.

c. Please refer to the SEC website for copies of all SEC Form 10Q reports for UGI Corporation issued within the last year. These can be found at:

- Quarter ended December 31, 2024: https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461425000008/ugi-20241231.htm

- Quarter ended March 31, 2025: https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461425000017/ugi-20250331.htm

- Quarter ended June 30, 2025: https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461425000045/ugi-20250630.htm

Prepared by or under the supervision of: Amy M. Keller

SDR-ROR-2

Request:

Please supply copies of the Company's balance sheets for each month/quarter for the last two years.

Response:

Please see Attachment SDR-ROR-2.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
Quarterly Balance Sheets
($ In Thousands)

Quarter End Date	Dec 31, 2023	Mar 31, 2024	Jun 30, 2024	Sep 30, 2024	Dec 31, 2024	Mar 31, 2025	Jun 30, 2025	Sep 30, 2025
Utility Plant	4,028,150	4,062,963	4,124,790	4,259,831	4,286,446	4,331,507	4,413,473	4,554,205
Other Investments	1,869	1,869	1,869	1,869	1,916	1,869	1,680	1,693
Cash and Cash Equivalents	32,132	21,360	9,059	10,107	12,023	14,226	8,686	14,498
Accounts Receivable	248,456	269,891	202,161	185,963	241,870	207,442	136,367	113,573
Other Receivables	77,426	61,961	20,154	20,285	98,461	69,187	21,249	20,324
Other Assets	627,358	629,778	639,711	612,750	660,826	590,217	598,867	630,965
Total Assets	$ 5,015,392	$ 5,047,823	$ 4,997,743	$ 5,090,804	$ 5,301,541	$ 5,214,448	$ 5,180,322	$ 5,335,258
Current and Accrued Liabilities	502,237	402,843	340,180	487,655	426,055	256,684	443,510	494,845
Other Non-current Liabilities	100,101	105,426	98,414	83,577	74,741	72,900	68,936	73,621
Long-term Debt	1,625,856	1,624,358	1,622,860	1,621,363	1,791,427	1,789,926	1,596,315	1,690,869
Other Deferred Liabilities	1,090,582	1,077,432	1,078,192	1,098,899	1,099,998	1,128,751	1,108,245	1,118,244
Total Liabilities	3,318,776	3,210,059	3,139,645	3,291,494	3,392,220	3,248,261	3,217,006	3,377,580
Equity	1,696,615	1,837,763	1,858,099	1,799,310	1,909,321	1,966,187	1,963,316	1,957,677
Total Liabilities and Equity	$ 5,015,391	$ 5,047,822	$ 4,997,744	$ 5,090,804	$ 5,301,541	$ 5,214,449	$ 5,180,322	$ 5,335,257

SDR-ROR-3

Request:

Please provide the bond rating history for the Company and, if applicable, its parent from the major credit rating agencies for the last five years.

Response:

Please see Attachment SDR-ROR-3.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Bond Rating History

	Fiscal Period End				
UGI Corporation	2021	2022	2023	2024	2025
Egan Jones					
Local Currency (LC) Senior Unsecured	BBB-	A-	BBB+	BBB	BBB
Foreign Currency (FC) Senior Unsecured	BBB-	A-	BBB+	BBB	BBB
Local Currency Commercial Paper	A1	A1+	A1	A1	A1
Foreign Currency Commercial Paper	A1	A1+	A1	A1	A1

	Fiscal Period End				
UGI Utilities, Inc.	2021	2022	2023	2024	2025
Fitch					
LT Issuer Default Rating	A-	A-	A-	A-	A-
Senior Unsecured Debt	A	A	A	A	A
*S&P					
LT Local Issuer Credit					
LT Foreign Issuer Credit					
Moody's					
Senior Unsecured Debt	A2	A2	A3	A3	A3
Long Term Rating	A2	A2	A3	A3	A3

***S&P does not publish a rating on UGI Utilities, Inc. debt**

SDR-ROR-4

Request:

Please provide copies of all bond rating reports relating to the Company and, if applicable, its parent for the past two years.

Response:

Please see the following attachments for the bond rating reports for UGI Utilities, Inc. which have been uploaded to the Commission's SharePoint site. Those materials will be served upon the parties via a secure OneDrive link:

Attachment SDR-ROR-4.1 for Fitch rating action dated July 26, 2024

Attachment SDR-ROR-4.2 for Moody's rating action dated June 17, 2024

Attachment SDR-ROR-4.3 for Moody's rating action dated June 24, 2025

Attachment SDR-ROR-4.4 for Fitch rating action dated July 21, 2025

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-5

Request:

Please provide a work paper showing the derivation of the Company's current AFUDC rate.

Response:

Please see the response for II-A-11.

Prepared by or under the supervision of: Amy M. Keller

SDR-ROR-6

Request:

Please supply copies of all presentations by the Company's and, if applicable, its parent's management to securities analysts during the past 2 years. This would include presentations of financial projections.

Response:

Copies of securities analysts presentations for 2024 and 2025 can be found at the following link: https://www.ugicorp.com/investors/financial-reports/events-and-presentations

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-7

Request:

Please provide a listing of all securities issuances for the Company and, if applicable, its parent projected for the next two years. The response should identify for each projected issuance the date, dollar amount, type of security, and effective cost rate.

Response:

UGI Utilities, Inc. does not have publicly traded stock. UGI Corp ("the Parent"), the parent company of UGI Utilities, Inc., does have publicly traded stock.

On May 25, 2021, the Parent issued 2.2 million “Equity Units” with a total notional value of $220 million. The Equity Units were equity-linked securities and not Common Stock. Each Equity Unit was a mandatory convertible, hybrid security that combined a “Forward Contract” and a 10% undivided interest in one share “Convertible Preferred Stock” of the Parent. The Equity Units included a requirement to remarket the Convertible Preferred Stock approximately three years after issuance (May 2024).

Pursuant to the terms of the Equity Units, in May 2024, the Parent announced the unsuccessful final remarketing of its Convertible Preferred Stock. As a result, each holder of an Equity Unit received 2.2973 shares of Parent Common Stock, without par value, with cash paid in lieu of any fractional shares.

In the event of a successful remarketing of the Convertible Preferred Stock, the Parent would still have provided such Common Stock to Equity Unit holders due to the terms of the Forward Contract.

During the third quarter of Fiscal 2024, the Parent (i) made the final payment to settle the Forward Contract in full; (ii) canceled the Convertible Preferred Stock; and (iii) in a non-cash transaction, converted the Equity Units into 5,054,030 shares of Parent Common Stock and issued the shares to the holders of the Equity Units under the Forward Contract.

As noted above, the Equity Units are not common stock, although they contain terms that eventually convert a portion into Parent Common Stock.

All terms and requirements under the Equity Units are satisfied. The Equity Units are fully settled as of June 2024.

SDR-ROR-7 (Continued)

Please reference Schedule B-6 of Exhibit A (Fully Projected) for details of expected debt issuances for UGI Utilities, Inc. through Fiscal 2027.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-8

Request:

Please identify all of the Company's and, if applicable, its parent's publicly underwritten common stock issuances written in the last five years. Identify which such issuances were related to mergers or acquisitions, and which were undertaken to fund facility investments in utility plant and equipment.

Response:

The Company has not issued stock in the last five years.

The Parent (UGI Corporation) has issued stock related to the below transaction in the last five years.

On May 25, 2021, the Parent issued 2.2 million “Equity Units” with a total notional value of $220 million. The Equity Units were equity-linked securities and not Common Stock. Each Equity Unit was a mandatory convertible, hybrid security that combined a “Forward Contract” and a 10% undivided interest in one share “Convertible Preferred Stock” of the Parent. The Equity Units included a requirement to remarket the Convertible Preferred Stock approximately three years after issuance (May 2024).

Pursuant to the terms of the Equity Units, in May 2024, the Parent announced the unsuccessful final remarketing of its Convertible Preferred Stock. As a result, each holder of an Equity Unit received 2.2973 shares of Parent Common Stock, without par value, with cash paid in lieu of any fractional shares.

In the event of a successful remarketing of the Convertible Preferred Stock, the Parent would still have provided such Common Stock to Equity Unit holders due to the terms of the Forward Contract.

During the third quarter of Fiscal 2024, the Parent (i) made the final payment to settle the Forward Contract in full; (ii) canceled the Convertible Preferred Stock; and (iii) in a non-cash transaction, converted the Equity Units into 5,054,030 shares of Parent Common Stock and issued the shares to the holders of the Equity Units under the Forward Contract.

As noted above, the Equity Units are not common stock, although they contain terms that eventually convert a portion into Parent Common Stock.

SDR-ROR-8 (Continued)

All terms and requirements under the Equity Units are satisfied. The Equity Units are fully settled as of June 2024.

The issuance of Equity Units was in conjunction with an acquisition by the Parent.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-9

Request:

Please identify any plan by the Company to refinance high cost long-term debt or preferred stock.

Response:

Please see the response to SDR-ROR-7.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-10

Request:

Please provide copies of all securities analysts' reports relating to the Company and/or its parent issued within the past 2 years.

Response:

Please see the following Janney analyst reports on UGI Corporation issued in 2024 and 2025 which have been uploaded via the Commission's SharePoint site. Those materials will be served upon the parties via a secure OneDrive link.

Attachment SDR-ROR-10.1 - Janney report dated Nov 20, 2023
Attachment SDR-ROR-10.2 - Janney report dated Dec 13, 2023
Attachment SDR-ROR-10.3 - Janney report dated Jan 11, 2024
Attachment SDR-ROR-10.4 - Janney report dated Feb 02, 2024
Attachment SDR-ROR-10.5 - Janney report dated May 02, 2024
Attachment SDR-ROR-10.6 - Janney report dated Jun 21, 2024
Attachment SDR-ROR-10.7 - Janney report dated Aug 09, 2024
Attachment SDR-ROR-10.8 - Janney report dated Nov 25, 2024
Attachment SDR-ROR-10.9 - Janney report dated Jan 28, 2025
Attachment SDR-ROR-10.10 - Janney report dated Jan 31, 2025
Attachment SDR-ROR-10.11 - Janney report dated Feb 06, 2025
Attachment SDR-ROR-10.12 - Janney report dated Mar 18, 2025
Attachment SDR-ROR-10.13 - Janney report dated May 09, 2025
Attachment SDR-ROR-10.14 - Janney report dated Aug 07, 2025
Attachment SDR-ROR-10.15 - Janney report dated Nov 24, 2025

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-11

Request:

If applicable, please supply a listing of all common equity infusions from the parent to the Company over the past five years. In each case, identify date and dollar amount.

Response:

The following schedule represents common equity infusion from UGI Corporation to UGI Utilities, Inc. for each of the last five fiscal years:

	(000's)
2021	$0
2022	$35,000 (April)
2023	$0
2024	$0
2025	$15,000 (April)

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-12

Request:

If applicable, please identify the Company's common dividend payments to its parent for each of the last five years.

Response:

The following schedule represents common dividend payments from UGI Utilities, Inc. to UGI Corporation for each of the last five fiscal years:

	(000's)
2021	$35,000
2022	$0
2023	$0
2024	$135,000
2025	$79,000

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-13

Request:

Please provide the latest year-by-year financial projections for the Company for the next five years. Also, please indicate the date these projections were prepared; whether approved by management; and whether the projections have been submitted to bond rating agencies. (Information should be treated in a confidential manner.)

Response:

UGI Gas prepares an annual Budget and three-year Plan. The Budget and Plan were approved in September 2025. These projections will be included in consolidated UGI Utilities, Inc. financial projections to be presented to bond rating agencies.

Please refer to the response to II-A-13 for a schedule of financial projections for Fiscal Years 2026 and 2027.

The projections for Fiscal Years 2028 and 2029 are confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-14

Request:

Please provide the Company's five-year construction budget.

Response:

The Company prepares a budget for the upcoming fiscal year and a plan for the three future years. The actual plant placed in service for the Fiscal Years ended September 30, 2024 and September 30, 2025, as well as the projected plant placed in service for the Fiscal Years ending September 30, 2026 and September 30, 2027, are provided on Attachment SDR-ROR-14.

The projection for Fiscal Year 2028 is confidential and will be made available to parties upon request and upon the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Vicky A. Schappell

UGI Utilities, Inc. - Gas Division
Plant Placed in Service by Budget Group
For the Years Ending September 30, 2024 through September 30, 2027

	FY2024	FY2025	FY2026	FY2027
Growth				
40G - New Business-Mains	$ 17,304,438	$ 22,131,807	$ 21,706,424	$ 21,390,212
40G1 - New Business-Mains GET Gas	585,815	-	-	-
50G - New Business-Services	40,793,718	43,243,516	41,948,346	42,924,111
51G - New Business-Meters	4,505,355	5,995,861	5,940,325	5,954,984
52G - New Business-Meter Installation	4,772,931	4,175,628	3,998,444	5,023,442
57G - New Business-Services GET Gas	899,908	-	-	-
46G - New Business Services to Mains		-		
94G - New Business-M & R Station Equipment	64,202	1,855,048	1,104,479	397,737
Subtotal Growth	**$ 68,926,367**	**$ 77,401,859**	**$ 74,698,018**	**$ 75,690,487**
IT				
14S - IS Information Services	$ 23,629,555	11,288,610	$ 43,731,515	12,032,402
Subtotal IT	**$ 23,629,555**	**$ 11,288,610**	**$ 43,731,515**	**$ 12,032,402**
Other				
02O - Building/Building Improvements/Land acquisition	$ 21,190,903	$ 8,251,103	$ 18,047,829	16,746,242
03O - Furniture and Office Equipment	12,597	14,024	194,555	240,388
04O - Fleet Capital and Related Equipment	9,966,742	11,871,000	11,247,639	11,671,501
07O - Operations Tool Blanket	2,828,023	2,544,667	1,833,995	2,373,995
11O - Corrosion Related Projects	5,586,193	4,040,182	9,302,495	5,597,470
13O - Gas Supply Projects	-	1,769	-	-
99U - GA Undistributed Overhead-Maintenance	2,102	-	-	-
Subtotal Other	**$ 39,586,561**	**$ 26,722,745**	**$ 40,626,513**	**$ 36,629,596**
Replacement and Betterment				
01O - Misc-Plant Equipment	$ 655,395	$ 769,665	$ 523,664	507,168
09O - Regulator Station Enhancements/Replacements	15,183,863	26,829,834	27,292,281	38,691,253
12O - Distribution System Reliability Projects	9,361,998	13,772,425	18,653,106	16,431,863
41M - Main Replacement- Leaks	9,198,381	6,576,361	1,534,638	250,800
42M - Main Replacement Compliance	-	448,989	1,762,928	883,820
43M - Replacement - Relocation	21,716,034	23,070,706	29,150,672	14,780,891
44M - Main Replacement- Bare Steel	41,277,354	44,003,768	153,185,813	258,170,813
45M - Main Replacement- Cast Iron	100,563,852	120,632,879	31,468,620	-
47M - Main Replacement- Priority Plastic	-	609,060	1,050,618	1,495,230
51M - Replacement Meters/ERTs	6,629,915	7,882,299	6,869,604	7,654,387
52M - Blanket Meter Installations	3,609,899	4,681,225	5,034,651	5,034,651
53M - Regulator Equipment	47,664	83,133	49,591	49,591
53M1 - Mercury Regulator Removal	171,679	-	-	-
54M - Gas Maint-House Reg Installations	-	218,720	-	-
55M - Meter Set Rebuild[1]	(24,731)	-	-	-
58M - Replacement services not associated with main	34,474,671	42,128,726	33,751,899	38,975,794
59R - Cost of Removal-Services	765,317	930,166	-	-
60M - Transmission Replacement	571,765	70,533	1,197,907	715,168
Subtotal Replacement and Betterment	**$ 244,203,055**	**$ 292,708,487**	**$ 311,525,991**	**$ 383,641,428**
Total	**$ 376,345,538**	**$ 408,121,702**	**$ 470,582,036**	**$ 507,993,913**

[1] Credit balance related to a correction in the project classification when the project was unitized in 2024

SDR-ROR-15

Request:

Please identify the Company's and, if applicable, its parent's capital structure targets (percentages of capital types). Provide the complete basis for the capital structure targets.

Response:

Please see the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, and UGI Gas Exhibit B for capital structure targets.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-16

Request:

For each month, of the most recent 24 months, please supply the Company's

a. short-term debt balance;

b. short-term debt interest rate;

c. balance of construction work in progress; and

d. balance of construction work in progress which is eligible for AFUDC accrual.

Response:

Please refer to Attachment SDR-ROR-16 for the requested information.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
SHORT TERM DEBT BALANCE AND CWIP BALANCE
FOR THE PERIOD OF OCTOBER 2023 THROUGH SEPTEMBER 2025

Year	Month	Short Term Debt Balance (000's)	Short Term Debt Interest Rate	Construction Work in Progress Balance (000's)	CWIP Eligible for AFUDC Balance (000's)
2023	October	$ 261,666	6.3091%	$ 57,573	$ 30,675
2023	November	$ 191,697	6.3518%	$ 62,315	$ 33,201
2023	December	$ 172,527	6.3206%	$ 66,709	$ 35,542
2024	January	$ 134,188	6.3242%	$ 79,846	$ 42,542
2024	February	$ 95,848	6.3185%	$ 88,286	$ 47,039
2024	March	$ 83,388	6.3026%	$ 104,743	$ 55,807
2024	April	$ 32,588	6.3050%	$ 107,923	$ 57,501
2024	May	$ 22,045	6.3009%	$ 113,054	$ 60,235
2024	June	$ 33,547	6.3007%	$ 108,757	$ 57,946
2024	July	$ 74,762	6.3312%	$ 101,703	$ 54,187
2024	August	$ 113,101	6.3139%	$ 102,274	$ 54,491
2024	September	$ 182,112	6.1660%	$ 69,343	$ 36,946
2024	October	$ 230,313	5.9816%	$ 72,664	$ 48,557
2024	November	$ 86,367	5.6966%	$ 74,510	$ 49,790
2024	December	$ 110,358	5.4380%	$ 79,190	$ 52,918
2025	January	$ 87,327	5.2991%	$ 83,257	$ 55,636
2025	February	$ 47,982	5.1242%	$ 87,908	$ 58,744
2025	March	$ 35,507	4.9302%	$ 98,837	$ 66,047
2025	April	$ -	4.8205%	$ 108,242	$ 72,331
2025	May	$ -	4.6833%	$ 116,164	$ 77,625
2025	June	$ 42,224	4.5801%	$ 123,823	$ 82,743
2025	July	$ 83,488	4.4630%	$ 126,336	$ 84,423
2025	August	$ 113,237	4.3571%	$ 137,539	$ 91,909
2025	September	$ 191,927	4.3571%	$ 99,469	$ 66,469

SDR-ROR-17

Request:

If applicable, please provide the currently authorized returns on equity for each of the parent's utility subsidiaries of the same industry type as the Company. In each case identify the approximate date when the current return on equity was approved by the state commission.

Response:

UGI Utilities, Inc. – Gas Division's most recent base rate case filing was approved by the Pennsylvania Public Utility Commission on September 11, 2025, with no definitive return on equity.

Mountaineer Gas Company's most recent base rate case filing was approved by the West Virginia Public Service Commission on December 21, 2023, with no definitive return on equity.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-18

Request:

Has the Utility reacquired or repurchased any debt within the last five years? If so, provide a summary of each gain or loss on reacquired debt, the date on which the utility commenced amortization of such a gain or loss, the regulatory commission decision addressing the treatment of such gain or loss on reacquired debt, if any, on interest expense.

Response:

In accordance with prudent corporate management practices, in November 2025, the Company repurchased $175 million in outstanding debt several months in advance of the due date. There was no gain or loss associated with the repurchase.

The repurchased debt was replaced with new debt. This debt refinancing was contemplated within the claimed debt cost in the Company's prior base rate filing at Docket No. R-2024-3052716 and is also reflected in the claimed debt cost in the Company's current base rate filing.

See Attachment SDR-ROR-18 for details of the debt refinancing.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Details of Senior Unsecured Notes Refinancing - November 2025
Dollars in thousands

Description	Amount	Interest Rate	Maturity Date	Repurchase Date	Issuance Date
Repurchased:					
Senior Unsecured Notes	$ 100,000	1.59%	6/15/2026	11/17/2025	6/15/2021
Senior Unsecured Notes	$ 75,000	1.64%	9/15/2026	11/17/2025	9/15/2021
	$ 175,000				
Newly Issued:					
Senior Unsecured Notes	$ 150,000	5.10%	11/15/2030	N/A	11/14/2025
Senior Unsecured Notes	$ 125,000	5.68%	11/15/2035	N/A	11/14/2025
	$ 275,000				

Note: The $100 million amount of newly issued notes in excess of the amount used to repurchase the notes maturing in 2026 is being used for general operating purposes.

SDR-ROR-19

Request:

Fully identify all debt (other than instruments traded in public markets) owed to all shareholders, corporate officers, or members of the board of directors, its affiliates, parent company, or subsidiaries.

Response:

UGI Gas does not owe any debt to shareholders, corporate officers, or members of the board of directors, its affiliates, parent company, or subsidiaries.

Prepared by or under the supervision of: Amy M. Keller

SDR-ROR-20

Request:

Provide a summary statement of all stock dividends, splits, or par value changes during the two (2) year calendar period preceding the rate case filing.

Response:

UGI Gas does not have publicly traded common stock and has not issued stock as a dividend to UGI Corporation, its 100% common equity owner. There were no stock splits or par value changes in the previous two calendar years.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-21

Request:

If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system--consolidated, the reasons for this claim must be fully stated and supported.

Response:

UGI Utilities, Inc. - Gas Division is not basing its filing on the parent company or system - consolidated capital structures or capital costs.

Prepared by or under the supervision of: Dylan D'Ascendis

SDR-ROR-22

Request:

To the extent not provided in SDR III-A.13, supply projected capital requirements and sources of the filing utility, its parent and system-¬consolidated--for the test year and each of three (3) comparable future years.

Response:

Please refer to Attachment II-A-5 for the projected capital expenditures for Fiscal Years ending September 30, 2026 and September 30, 2027. The sources of funds may be internally generated contributions from the parent or from outside financing, as needed.

The projection for Fiscal Year 2028 is confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Vicky A. Schappell

SDR-ROR-23

Request:

To the extent not provided elsewhere, supply financial data of Company and/or parent for the last five (5) years.

a. Times interest earned ratio — pre and post tax basis.
b. Preferred stock dividend coverage ratio — post tax basis.
c. Times fixed charges earned ratio — pre tax basis.
d. Dividend payout ratio.
e. AFUDC as a percent of earnings available for common equity.
f. Construction work in progress as a percent of net utility plant.
g. Effective income tax rate.
h. Internal cash generations as a percent of total capital requirements.

Response:

Please refer to Attachment SDR-ROR-23 for the requested information of UGI Utilities, Inc. - Consolidated.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Select Financial Data for UGI Utilities, Inc. - Consolidated
For the Year Ended September 30,

	2021	2022	2023	2024	2025
a. Times Interest Earned Ratio - pre tax	4.42	5.26	4.76	4.52	4.11
Times Interest Earned Ratio - post tax	3.64	4.36	3.91	3.72	3.44
b. Preferred Stock Dividend Coverage ratio	N/A	N/A	N/A	N/A	N/A
c. Times Fixed Charges Earned Ratio	4.29	5.03	4.48	4.30	3.92
d. Dividend Payout Ratio	24%	0%	0%	62%	37%
e. AFUDC as a % of Net Utility Plant	0.025%	0.057%	0.095%	0.087%	0.085%
f. CWIP as a % of Net Utility Plant	2.46%	3.12%	1.84%	1.87%	2.41%
g. Effective Income Tax rate	22.83%	20.97%	22.46%	22.97%	21.65%
h. Internal Cash Generation as a % of Total Capital Requirements	69.5%	80.3%	71.7%	70.1%	73.8%

SUPPLEMENTAL DATA REQUESTS

REVENUE REQUIREMENTS

SDR-RR-1

Request:

Please provide a copy of the Company's detailed quarterly balance sheet and monthly income statements for the historic test year through the most recent month available.

Response:

Please see Attachment SDR-RR-1 for monthly income statements from October 2024 through November 2025. Please see Attachment SDR-ROR-2 for quarterly balance sheets.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Monthly Income Statements
(thousands of dollars)

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
Revenues														
Gas Utility Revenues	$ 61,106	$ 97,513	$ 163,954	$ 214,045	$ 169,941	$ 131,880	$ 83,718	$ 52,960	$ 40,823	$ 40,958	$ 40,674	$ 39,416	$ 67,108	$ 130,818
Other Operating Revenues	$ 6,663	$ 11,438	$ 21,153	$ 40,482	$ 25,343	$ 20,708	$ 11,333	$ 9,310	$ 8,129	$ 7,032	$ 6,163	$ 6,273	$ 7,980	$ 15,860
Total Operating Revenue	67,770	108,951	185,107	254,526	195,284	152,588	95,050	62,270	48,952	47,990	46,837	45,689	75,087	146,677
Expenses														
Operating Expense	4,214	4,939	3,931	4,857	4,537	4,209	4,843	4,880	4,201	4,752	5,817	4,660	4,392	4,452
Maintenance Expense	3,533	2,927	3,485	1,859	2,965	3,180	2,927	3,354	3,241	3,241	1,752	3,438	3,461	3,298
Customer Accounts Operations Expense	3,245	3,334	4,885	5,486	4,591	4,173	3,333	3,002	3,145	2,577	3,088	3,217	3,430	4,519
Customer Service, Information and Sales Expense	251	238	309	212	207	348	378	304	284	253	305	458	225	269
Admin and General Operation Expense	6,518	5,038	8,415	10,355	7,973	7,978	8,625	8,384	9,000	8,827	7,818	9,509	6,257	6,106
Depreciation and Amortization Expense	11,663	11,745	11,746	11,855	11,727	11,825	12,053	11,958	12,010	12,087	12,015	12,234	12,349	12,785
Other taxes	987	952	984	1,770	1,092	916	1,031	954	938	1,166	1,537	902	1,055	1,050
Storage, Transportation and Other	20,297	40,609	87,907	137,331	94,232	69,563	39,781	23,037	16,498	16,425	13,227	14,190	29,241	66,588
Interest Income/Interest Expense	(99)	(194)	(235)	(347)	(289)	(300)	(198)	(157)	(115)	113	56	(160)	(150)	(214)
Miscellaneous Income/Expense	(133)	1,394	(240)	(236)	138	(390)	(111)	(147)	44	(30)	(88)	2,366	948	1,274
Long Term Debt Interest	7,012	7,184	7,140	7,330	7,067	6,923	6,834	6,744	6,697	6,862	6,963	7,173	7,569	8,087
Total Expenses Before Taxes	57,488	78,165	128,327	180,471	134,239	108,428	79,496	62,312	55,942	56,273	52,489	57,988	68,778	108,214
Income Before Taxes	10,282	30,785	56,780	74,055	61,045	44,161	15,554	(42)	(6,989)	(8,283)	(5,652)	(12,299)	6,310	38,463
Tax Expense	2,263	6,877	12,920	16,654	13,631	10,058	3,474	(15)	(1,444)	(1,909)	(1,301)	(5,550)	1,439	8,667
Net Income	$ 8,019	$ 23,908	$ 43,861	$ 57,402	$ 47,414	$ 34,103	$ 12,080	$ (27)	$ (5,545)	$ (6,374)	$ (4,352)	$ (6,748)	$ 4,871	$ 29,796

SDR-RR-2

Request:

Please provide the actual number of customers by rate schedule as of December 31 for the last five years.

Response:

Please see Attachment SDR-RR-2.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Number of Customers Year End at December 31

Customer Class	2020	2021	2022	2023	2024
Rate R-Residential Non-Heating	25,676	24,568	23,303	22,163	21,365
Rate GL-Residential Gas Lights	38	39	35	31	31
Rate R-Residential Heat	495,951	507,733	519,589	515,796	527,753
Rate N-Commercial Non-Heating	3,309	3,314	3,239	3,073	3,135
Rate GL-Commercial Gas Lights	13	13	13	13	12
Rate N-Commercial Heat	46,452	46,379	46,293	44,637	45,297
Rate N-Industrial Non-Heating	107	104	107	96	100
Rate N-Industrial Heat	571	606	609	562	576
Rate RS-Retail and Standby	1	1	1	1	1
Sub-Total Retail	572,118	582,757	593,189	586,372	598,270
Rate RT- Residential Transportation	81,866	77,857	74,644	85,446	80,188
Rate NT-Non-Residential Transportation	18,744	19,059	19,484	21,497	20,922
Rate DS-Delivery Service	1,378	1,365	1,340	1,316	1,304
Rate XD-Extended Large Volume Delivery Service	109	115	113	113	113
Rate LFD-Large Firm Delivery Service	579	590	606	609	624
Rate IS-Interruptible Service - Transportation	300	285	268	258	244
Sub-Total Transportation	102,976	99,271	96,455	109,239	103,395
Grand Total	675,094	682,028	689,644	695,611	701,665

SDR-RR-3

Request:

Please provide the average number of customers by rate schedule for the last five years.

Response:

Please see Attachment SDR-RR-3.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Yearly Average Number of Customers for Period Ending September 30

Customer Class	2021	2022	2023	2024	2025
Rate R-Residential Non-Heating	24,929	23,798	22,676	21,693	20,950
Rate GL-Residential Gas Lights	38	37	34	31	31
Rate R-Residential Heat	497,429	507,586	514,450	517,153	524,170
Rate N-Commercial Non-Heating	3,307	3,294	3,201	3,081	3,120
Rate GL-Commercial Gas Lights	13	13	13	12	12
Rate N-Commercial Heat	46,313	45,983	45,599	44,633	45,220
Rate N-Industrial Non-Heating	106	103	102	97	100
Rate N-Industrial Heat	588	606	586	566	575
Rate RS-Retail and Standby	1	1	1	1	1
Sub-Total Retail	572,724	581,421	586,662	587,267	594,179
Rate RT- Residential Transportation	80,074	77,332	78,021	82,049	81,293
Rate NT-Non-Residential Transportation	18,690	19,249	19,964	21,203	20,745
Rate DS-Delivery Service	1,374	1,356	1,334	1,315	1,300
Rate XD-Extended Large Volume Delivery Service	110	112	113	113	113
Rate LFD-Large Firm Delivery Service	581	594	607	614	627
Rate IS-Interruptible Service - Transportation	295	282	267	258	238
Sub-Total Transportation	101,124	98,925	100,306	105,552	104,316
Grand Total	673,848	680,346	686,968	692,819	698,495

SDR-RR-4

Request:

Please provide the actual number of customers by rate schedule at the end of each month from the commencement of the historic test year through the most recent month available and update as additional data become available.

Response:

Please see Attachment SDR-RR-4.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Number of Customers - Monthly

Customer Class	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Rate R-Residential Non-Heating	21,204	21,279	21,365	21,390	21,207	21,108	20,860	20,753	20,694	20,602	20,489	20,447
Rate GL-Residential Gas Lights	30	31	31	31	31	31	31	31	30	30	30	30
Rate R-Residential Heat	520,678	524,529	527,753	528,171	528,538	528,423	526,499	524,448	522,477	520,187	519,050	519,287
Rate N-Commercial Non-Heating	3,097	3,131	3,135	3,145	3,137	3,139	3,136	3,112	3,114	3,103	3,095	3,094
Rate GL-Commercial Gas Lights	12	12	12	12	12	12	12	11	11	11	11	11
Rate N-Commercial Heat	44,649	44,997	45,297	45,416	45,515	45,555	45,612	45,362	45,194	45,025	45,037	44,978
Rate N-Industrial Non-Heating	100	101	100	102	100	97	101	99	98	100	99	101
Rate N-Industrial Heat	569	573	576	578	579	575	578	579	579	578	569	572
Rate RS-Retail and Standby	1	1	1	1	1	1	1	1	1	1	1	1
Sub-Total Retail	590,340	594,654	598,270	598,846	599,120	598,941	596,830	594,396	592,198	589,637	588,381	588,521
Rate RT- Residential Transportation	79,720	79,894	80,188	81,335	81,605	81,867	81,742	81,485	81,623	81,671	82,037	82,349
Rate NT-Non-Residential Transportation	20,997	20,913	20,922	20,903	20,840	20,727	20,567	20,630	20,642	20,617	20,566	20,620
Rate DS-Delivery Service	1,303	1,304	1,304	1,304	1,301	1,301	1,298	1,296	1,297	1,299	1,298	1,295
Rate XD-Extended Large Volume Delivery Service	113	113	113	113	113	113	113	113	113	113	113	113
Rate LFD-Large Firm Delivery Service	619	623	624	622	625	626	626	628	630	630	633	632
Rate IS-Interruptible Service - Transportation	249	244	244	241	241	238	238	237	236	228	229	229
Sub-Total Transportation	103,001	103,091	103,395	104,518	104,725	104,872	104,584	104,389	104,541	104,558	104,876	105,238
Grand Total	693,341	697,745	701,665	703,364	703,845	703,813	701,414	698,785	696,739	694,195	693,257	693,759

SDR-RR-5

Request:

If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by rate schedule as of December 31 for the last three years. Where applicable, separately identify sales and transportation throughput.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10, as well as the responses to SDR-RR-9, SDR-RR-10, and SDR-RR-11 for a description of the UGI Gas model used for forecasting sales for the Residential Heating ("RH") and Commercial Heating ("CH") rate groups, including supporting data.

Use per customer values for rate classes and class subgroups were established pursuant to the following:

The projected RH use per customer was established on a combined Rate R/RT - Heating total basis per the UGI Gas model detailed in Attachment SDR-RR-11(a). Weather normalized sales for Rate RT - Heating customers were then utilized to derive the separate Rate RT - Heating and Rate R - Heating use per customer values from the combined Rate R/RT - Heating value. Please see Attachment SDR-RR-5(a) for the actual and normalized sales utilized for Rate RT - Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate R - Heating use per customer value.

Actual sales were normalized for combined Residential Non-Heating – Rate R and Rate RT in order to project combined use per customer in total. Please see Attachment SDR-RR-5(b) for the actual and normalized sales utilized for the combined Rate R/RT-Non-Heating value. Weather normalized sales for Non-Heating Rate RT were then utilized to derive the separate Rate RT and Rate R – Non-Heating customer values from the combined Rate R/RT – Non-Heating value. Please see Attachment SDR-RR-5(c) for the actual and normalized sales utilized for Rate RT- Non-Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate R – Non-Heating use per customer value.

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate RT (Heating and Non-Heating) use per customer value.

SDR-RR-5 (Continued)

The projected CH use per customer was established on a combined Rate N/NT/DS - Heating total basis per the UGI Gas model detailed in Attachment SDR-RR-11(b). Weather normalized sales for Rate NT – Commercial Heating customers and budgeted sales for Rate DS – Commercial Heating were then utilized to derive the separate Rate NT – Commercial Heating, Rate N – Commercial Heating and Rate DS – Commercial Heating use per customer values from the combined Rate N/NT/DS – Commercial Heating value. Please see Attachment SDR-RR-5(d) for the actual and normalized sales utilized for Rate NT – Commercial Heating and Attachment SDR-RR-5(e) for the budget sales for Rate DS – Commercial Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate N – Commercial Heating use per customer value.

Actual sales were normalized for combined Rate N – Commercial Non-Heating, Rate NT - Commercial Non-Heating and Rate DS – Commercial Non-Heating in order to project combined Rate N/NT/DS – Commercial Non-Heating use per customer in total. Please see Attachment SDR-RR-5(f) for the actual and normalized sales utilized for the combined Rate Commercial N/NT/DS-Non-Heating value. Weather normalized sales for Rate NT – Commercial Non-Heating and budgeted sales for Rate DS – Commercial Non-Heating were then utilized to derive the separate Rate NT – Commercial Non-Heating, Rate N – Commercial Non-Heating and Rate DS – Commercial Non-Heating use per customer values from the combined Rate N/NT/DS – Commercial Non-Heating value. Please see Attachment SDR-RR-5(g) for the actual and normalized sales utilized for Rate NT – Commercial Non-Heating and Attachment SDR-RR-5(h) for the budget sales for Rate DS - Commercial Non-Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate N – Commercial Non-Heating use per customer value.

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate NT (Heating and Non-Heating) use per customer value.

Actual sales were normalized for combined Rate N – Industrial, Rate NT - Industrial and Rate DS – Industrial in order to project combined Rate N/NT/DS – Industrial use per customer in total. Please see Attachment SDR-RR-5(i) for the actual and normalized sales utilized for the combined Rate N/NT/DS - Industrial value. Weather normalized sales for Rate NT – Industrial and budgeted sales for Rate DS – Industrial were then utilized to derive the separate Rate NT – Industrial, Rate N – Industrial and Rate DS – Industrial use per customer values from the combined Rate N/NT/DS – Industrial value. Please see Attachment SDR-RR-5(j) for the actual and normalized sales utilized for Rate NT – Industrial and Attachment SDR-RR-5(k) for the budget sales for Rate DS - Industrial. Please see UGI Gas Exhibit SAE-7(a) For the derivation of the Rate N – Industrial use per customer value.

SDR-RR-5 (Continued)

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate DS (Heating and Non-Heating) use per customer value.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	3,242	21,886	4,584	17,302	455	37.9910	309	(5,563)	16,323	6.75	5.03	
Nov-03	3,208	25,262	4,584	20,678	574	36.0283	647	2,632	27,894	7.87	8.70	
Dec-03	2,854	42,668	4,584	38,084	999	38.1109	895	(3,975)	38,693	14.95	13.56	
Jan-04	2,795	56,316	4,584	51,732	1,357	38.1223	1,069	(10,980)	45,336	20.15	16.22	
Feb-04	2,818	44,506	4,584	39,922	983	40.5972	909	(3,020)	41,486	15.79	14.72	
Mar-04	2,711	33,249	4,584	28,665	736	38.9677	749	522	33,770	12.26	12.46	
Apr-04	2,680	19,041	4,584	14,457	438	33.0030	410	(926)	18,115	7.10	6.76	
May-04	2,666	6,880	4,584	2,297	97	23.6091	155	1,363	8,243	2.58	3.09	
Jun-04	2,651	4,835	4,584	251	52	4.8398	27	(121)	4,714	1.82	1.78	
Jul-04	2,640	4,529	4,529	0	1	0.0000	0	0	4,529	1.72	1.72	
Aug-04	2,624	4,638	4,638	0	21	0.0000	8	0	4,638	1.77	1.77	
Sep-04	2,615	5,662	4,584	1,078	59	18.2817	68	165	5,827	2.17	2.23	88.03
Oct-04	2,719	16,694	4,584	12,111	416	29.1026	309	(3,118)	13,576	6.14	4.99	87.99
Nov-04	2,749	22,851	4,584	18,267	627	29.1419	647	588	23,438	8.31	8.53	87.82
Dec-04	2,686	36,205	4,584	31,621	1,005	31.4613	895	(3,463)	32,741	13.48	12.19	86.45
Jan-05	2,661	44,972	4,584	40,388	1,217	33.1845	1,069	(4,914)	40,058	16.90	15.05	85.28
Feb-05	2,641	36,646	4,584	32,062	939	34.1515	881	(1,975)	34,671	13.88	13.13	83.69
Mar-05	2,632	35,943	4,584	31,359	942	33.2864	749	(6,428)	29,515	13.66	11.21	82.44
Apr-05	2,620	17,062	4,584	12,478	377	33.1088	410	1,096	18,158	6.51	6.93	82.62
May-05	2,603	11,244	4,584	6,660	268	24.8482	155	(2,809)	8,435	4.32	3.24	82.76
Jun-05	2,613	3,503	3,503	0	16	0.0000	27	0	3,503	1.34	1.34	82.33
Jul-05	2,596	3,713	3,713	0	0	0.0000	0	0	3,713	1.43	1.43	82.04
Aug-05	2,581	4,116	4,116	0	1	0.0000	8	0	4,116	1.59	1.59	81.87
Sep-05	2,559	4,512	3,914	597	35	17.1506	68	569	5,081	1.76	1.99	81.63
Oct-05	2,544	12,749	3,914	8,834	351	25.1601	309	(1,060)	11,689	5.01	4.59	81.23
Nov-05	2,523	19,963	3,914	16,048	600	26.7670	647	1,270	21,233	7.91	8.42	81.12
Dec-05	2,457	36,407	3,914	32,493	1,121	28.9853	895	(6,551)	29,856	14.82	12.15	81.08
Jan-06	2,363	29,334	3,914	25,420	890	28.5477	1,069	5,097	34,432	12.41	14.57	80.60
Feb-06	2,267	30,811	3,914	26,896	945	28.4599	881	(1,823)	28,988	13.59	12.79	80.26
Mar-06	2,244	24,292	3,914	20,378	775	26.2996	749	(680)	23,613	10.83	10.52	79.56
Apr-06	2,502	13,782	3,914	9,868	390	25.3028	410	506	14,289	5.51	5.71	78.34
May-06	2,587	6,923	3,914	3,009	184	16.3248	155	(479)	6,445	2.68	2.49	77.60
Jun-06	2,608	3,124	3,124	0	44	0.0000	27	0	3,124	1.20	1.20	77.45
Jul-06	2,602	3,932	3,932	0	1	0.0000	0	0	3,932	1.51	1.51	77.53
Aug-06	2,585	4,072	4,072	0	5	0.0000	8	0	4,072	1.58	1.58	77.51
Sep-06	2,579	5,981	4,002	1,979	123	16.1168	68	(883)	5,098	2.32	1.98	77.51
Oct-06	2,548	14,277	4,002	10,275	428	24.0320	309	(2,849)	11,428	5.60	4.49	77.40
Nov-06	2,507	17,192	4,002	13,189	552	23.8801	647	2,261	19,453	6.86	7.76	76.74
Dec-06	2,464	26,384	4,002	22,382	813	27.5219	895	2,250	28,634	10.71	11.62	76.21
Jan-07	2,438	31,729	4,002	27,726	997	27.8099	1,069	2,002	33,731	13.01	13.84	75.47
Feb-07	2,392	38,708	4,002	34,706	1,178	29.4705	881	(8,743)	29,966	16.18	12.53	75.21
Mar-07	2,351	29,239	4,002	25,237	824	30.6176	749	(2,305)	26,935	12.44	11.46	76.15
Apr-07	2,401	19,949	4,002	15,947	552	28.9066	410	(4,095)	15,854	8.31	6.60	77.04
May-07	2,386	6,783	4,002	2,780	142	19.5170	155	245	7,027	2.84	2.95	77.49
Jun-07	2,361	3,298	3,298	0	23	0.0000	27	0	3,298	1.40	1.40	77.69
Jul-07	2,344	3,551	3,551	0	13	0.0000	0	0	3,551	1.51	1.51	77.70
Aug-07	2,316	3,749	3,749	0	22	0.0000	8	0	3,749	1.62	1.62	77.74
Sep-07	2,278	4,459	3,650	809	72	11.2112	68	(47)	4,412	1.96	1.94	77.70
Oct-07	2,254	7,713	3,650	4,063	222	18.2851	309	1,587	9,300	3.42	4.13	77.34
Nov-07	2,227	20,397	3,650	16,748	739	22.6475	647	(2,095)	18,303	9.16	8.22	77.80
Dec-07	2,204	28,148	3,650	24,498	1,006	24.3486	895	(2,706)	25,442	12.77	11.54	77.72
Jan-08	2,151	31,126	3,650	27,476	1,051	26.1522	1,069	481	31,606	14.47	14.69	78.58
Feb-08	2,111	30,289	3,650	26,640	975	27.3266	909	(1,800)	28,489	14.35	13.50	79.55
Mar-08	2,070	23,719	3,650	20,069	819	24.5179	749	(1,705)	22,014	11.46	10.63	78.73

UGI Utilities, Inc. - Gas Division
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Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-08	2,019	10,791	3,650	7,141	371	19.2520	410	752	11,543	5.34	5.72	77.84
May-08	1,980	6,720	3,650	3,071	275	11.1644	155	(1,340)	5,380	3.39	2.72	77.61
Jun-08	1,960	2,733	2,733	0	18	0.0000	27	0	2,733	1.39	1.39	77.61
Jul-08	1,947	2,967	2,967	0	0	0.0000	0	0	2,967	1.52	1.52	77.62
Aug-08	1,935	2,920	2,920	0	14	0.0000	8	0	2,920	1.51	1.51	77.51
Sep-08	1,916	3,942	2,943	998	80	12.4046	68	(155)	3,787	2.06	1.98	77.55
Oct-08	2,154	11,472	2,943	8,528	468	18.2281	309	(2,896)	8,576	5.33	3.98	77.41
Nov-08	2,802	22,206	2,943	19,262	721	26.6978	647	(1,989)	20,217	7.92	7.22	76.40
Dec-08	2,994	38,967	2,943	36,024	1,016	35.4415	895	(4,303)	34,664	13.02	11.58	76.44
Jan-09	3,137	54,249	2,943	51,305	1,292	39.6950	1,069	(8,871)	45,377	17.29	14.47	76.21
Feb-09	3,124	42,883	2,943	39,940	927	43.0875	881	(1,980)	40,904	13.73	13.09	75.81
Mar-09	3,096	33,892	2,943	30,948	774	39.9963	749	(991)	32,901	10.95	10.63	75.80
Apr-09	3,079	17,220	2,943	14,277	419	34.0585	410	(313)	16,907	5.59	5.49	75.57
May-09	3,488	8,458	2,943	5,515	179	30.7858	155	(743)	7,715	2.42	2.21	75.07
Jun-09	3,657	5,706	2,943	2,763	41	32.4221	27	(446)	5,260	1.56	1.44	75.11
Jul-09	3,819	6,251	6,251	0	15	0.0000	0	0	6,251	1.64	1.64	75.22
Aug-09	3,782	5,978	5,978	0	16	0.0000	8	0	5,978	1.58	1.58	75.29
Sep-09	3,767	8,105	6,114	1,991	118	16.8874	68	(843)	7,262	2.15	1.93	75.25
Oct-09	3,757	18,655	6,114	12,541	440	28.4957	309	(3,736)	14,919	4.97	3.97	75.24
Nov-09	5,372	31,143	6,114	25,029	571	43.8471	647	3,340	34,483	5.80	6.42	74.44
Dec-09	5,655	77,540	6,114	71,426	1,055	67.6854	895	(10,847)	66,692	13.71	11.79	74.66
Jan-10	5,953	101,671	6,114	95,557	1,157	82.5878	1,069	(7,270)	94,400	17.08	15.86	76.05
Feb-10	7,521	104,397	6,114	98,283	1,014	96.9108	881	(12,905)	91,492	13.88	12.16	75.12
Mar-10	7,708	77,705	6,114	71,591	627	114.1634	749	13,917	91,622	10.08	11.89	76.38
Apr-10	7,765	36,959	6,114	30,845	325	94.9544	410	8,086	45,045	4.76	5.80	76.69
May-10	7,775	19,222	6,114	13,108	153	85.5190	155	148	19,369	2.47	2.49	76.97
Jun-10	7,912	13,184	6,114	7,070	25	90.2367	27	148	13,332	1.67	1.69	77.22
Jul-10	7,995	12,436	12,436	0	4	0.0000	0	0	12,436	1.56	1.56	77.13
Aug-10	7,994	11,765	11,765	0	7	0.0000	8	0	11,765	1.47	1.47	77.03
Sep-10	8,067	13,806	12,100	1,706	67	25.6351	68	37	13,843	1.71	1.72	76.81
Oct-10	8,631	41,097	12,100	28,997	383	75.7411	309	(5,593)	35,504	4.76	4.11	76.96
Nov-10	9,341	80,086	12,100	67,986	669	101.6140	647	(2,242)	77,844	8.57	8.33	78.87
Dec-10	10,972	180,306	12,100	168,205	1,162	144.7262	895	(38,675)	141,630	16.43	12.91	79.99
Jan-11	11,639	226,598	12,100	214,498	1,251	171.4996	1,069	(31,165)	195,433	19.47	16.79	80.92
Feb-11	12,074	179,500	12,100	167,400	955	175.2085	881	(13,041)	166,459	14.87	13.79	82.54
Mar-11	12,279	152,805	12,100	140,705	836	168.2477	749	(14,687)	138,118	12.44	11.25	81.90
Apr-11	12,315	80,577	12,100	68,477	414	165.3461	410	(685)	79,892	6.54	6.49	82.59
May-11	12,304	30,237	12,100	18,137	125	144.6740	155	4,287	34,525	2.46	2.81	82.90
Jun-11	12,459	20,122	12,100	8,021	21	155.0101	27	864	20,985	1.62	1.68	82.90
Jul-11	12,497	19,962	19,962	0	1	0.0000	0	0	19,962	1.60	1.60	82.94
Aug-11	12,469	18,453	18,453	0	10	0.0000	8	0	18,453	1.48	1.48	82.95
Sep-11	13,059	25,492	19,207	6,285	74	85.0923	68	(499)	24,993	1.95	1.91	83.15
Oct-11	14,323	76,755	19,207	57,548	400	144.0076	309	(13,050)	63,705	5.36	4.45	83.48
Nov-11	17,565	124,148	19,207	104,941	559	187.8033	647	16,568	140,716	7.07	8.01	83.16
Dec-11	21,740	243,560	19,207	224,353	843	266.1311	895	13,834	257,394	11.20	11.84	82.09
Jan-12	24,423	348,998	19,207	329,790	1,002	329.2297	1,069	22,156	371,154	14.29	15.20	80.50
Feb-12	25,558	323,666	19,207	304,459	814	374.0066	909	35,513	359,179	12.66	14.05	80.77
Mar-12	26,473	202,487	19,207	183,280	487	376.4569	749	98,686	301,173	7.65	11.38	80.89
Apr-12	26,901	150,838	19,207	131,631	437	301.3969	410	(8,058)	142,780	5.61	5.31	79.71
May-12	27,726	51,048	19,207	31,841	73	437.6367	155	35,992	87,041	1.84	3.14	80.05
Jun-12	28,074	47,719	19,207	28,512	39	369.5168	27	(4,305)	43,414	1.70	1.55	79.91
Jul-12	28,140	43,057	43,057	0	1	0.0000	0	0	43,057	1.53	1.53	79.84
Aug-12	29,133	41,579	41,579	0	7	0.0000	8	0	41,579	1.43	1.43	79.79
Sep-12	29,597	63,792	42,318	21,474	110	195.0598	68	(8,210)	55,582	2.16	1.88	79.75

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Oct-12	29,987	124,711	42,318	82,393	335	245.5936	309	(6,504)	118,206	4.16	3.94	79.25
Nov-12	30,377	309,952	42,318	267,634	785	341.1240	647	(46,926)	263,025	10.20	8.66	79.90
Dec-12	30,927	370,508	42,318	328,190	853	384.5490	895	15,981	386,489	11.98	12.50	80.55
Jan-13	32,253	489,684	42,318	447,366	1,047	427.3128	1,069	9,431	499,115	15.18	15.48	80.83
Feb-13	32,392	495,314	42,318	452,996	974	464.9974	881	(43,333)	451,981	15.29	13.95	80.73
Mar-13	32,467	436,598	42,318	394,280	884	446.2572	749	(60,033)	376,565	13.45	11.60	80.95
Apr-13	32,377	217,377	42,318	175,059	427	410.2093	410	(6,873)	210,504	6.71	6.50	82.15
May-13	32,271	81,338	42,318	39,020	178	218.7492	155	(5,114)	76,224	2.52	2.36	81.37
Jun-13	32,398	44,643	42,318	2,325	21	110.8142	27	667	45,310	1.38	1.40	81.22
Jul-13	32,542	49,405	49,405	0	4	0.0000	0	0	49,405	1.52	1.52	81.21
Aug-13	32,620	48,748	48,748	0	12	0.0000	8	0	48,748	1.49	1.49	81.28
Sep-13	33,115	79,156	49,077	30,079	143	210.8278	68	(15,743)	63,413	2.39	1.91	81.31
Oct-13	33,746	138,652	49,077	89,575	327	273.6270	309	(5,024)	133,627	4.11	3.96	81.33
Nov-13	36,732	343,595	49,077	294,518	773	381.0695	647	(47,966)	295,629	9.35	8.05	80.72
Dec-13	39,635	542,534	49,077	493,458	1,012	487.6685	895	(56,994)	485,540	13.69	12.25	80.47
Jan-14	40,825	775,157	49,077	726,081	1,310	554.1929	1,069	(133,648)	641,509	18.99	15.71	80.71
Feb-14	41,145	700,114	49,077	651,037	1,114	584.4399	881	(136,146)	563,968	17.02	13.71	80.47
Mar-14	41,156	591,900	49,077	542,824	976	555.9691	749	(126,403)	465,497	14.38	11.31	80.18
Apr-14	39,996	290,388	49,077	241,312	467	517.1654	410	(29,274)	261,114	7.26	6.53	80.21
May-14	39,257	102,499	49,077	53,423	152	350.4194	155	892	103,392	2.61	2.63	80.48
Jun-14	38,710	55,661	49,077	6,585	14	485.8249	27	6,532	62,194	1.44	1.61	80.69
Jul-14	38,359	57,939	57,939	0	10	0.0000	0	0	57,939	1.51	1.51	80.68
Aug-14	39,022	57,536	57,536	0	13	0.0000	8	0	57,536	1.47	1.47	80.66
Sep-14	39,554	77,654	57,737	19,916	98	202.3980	68	(6,153)	71,500	1.96	1.81	80.55
Oct-14	40,571	153,659	57,737	95,922	303	316.8540	309	1,986	155,645	3.79	3.84	80.43
Nov-14	42,137	406,715	57,737	348,977	759	459.8146	647	(51,477)	355,237	9.65	8.43	80.81
Dec-14	43,327	559,097	57,737	501,359	909	551.4105	895	(7,847)	551,250	12.90	12.72	81.28
Jan-15	44,529	783,215	57,737	725,477	1,231	589.3861	1,069	(95,424)	687,791	17.59	15.45	81.01
Feb-15	45,059	855,825	57,737	798,088	1,275	625.9176	881	(246,655)	609,171	18.99	13.52	80.83
Mar-15	45,335	655,824	57,737	598,087	960	623.0237	749	(131,442)	524,382	14.47	11.57	81.08
Apr-15	45,044	276,725	57,737	218,988	403	543.2216	410	3,733	280,458	6.14	6.23	80.78
May-15	46,245	90,809	57,737	33,072	83	399.4403	155	28,841	119,650	1.96	2.59	80.73
Jun-15	47,373	65,898	57,737	8,160	32	251.7466	27	(1,363)	64,534	1.39	1.36	80.49
Jul-15	47,085	70,772	70,772	0	4	0.0000	0	0	70,772	1.50	1.50	80.48
Aug-15	46,832	67,608	67,608	0	6	0.0000	8	0	67,608	1.44	1.44	80.45
Sep-15	46,845	74,435	69,190	5,245	42	123.5546	68	3,157	77,591	1.59	1.66	80.30
Oct-15	47,740	232,342	69,190	163,152	378	431.7648	309	(29,737)	202,605	4.87	4.24	80.71
Nov-15	48,232	316,760	69,190	247,570	508	487.0598	647	67,558	384,317	6.57	7.97	80.25
Dec-15	49,454	411,448	69,190	342,258	625	547.8129	895	148,034	559,482	8.32	11.31	78.84
Jan-16	49,653	798,392	69,190	729,202	1,130	645.4790	1,069	(39,185)	759,207	16.08	15.29	78.68
Feb-16	49,526	703,638	69,190	634,448	936	678.0323	909	(18,117)	685,521	14.21	13.84	79.00
Mar-16	49,288	452,398	69,190	383,208	582	658.7573	749	110,201	562,599	9.18	11.41	78.85
Apr-16	48,927	312,465	69,190	243,276	468	519.7581	410	(30,175)	282,291	6.39	5.77	78.39
May-16	49,234	158,152	69,190	88,962	221	402.7513	155	(26,536)	131,616	3.21	2.67	78.48
Jun-16	49,333	72,533	69,190	3,343	25	134.8360	27	297	72,830	1.47	1.48	78.59
Jul-16	49,251	71,857	71,857	0	2	0.0000	0	0	71,857	1.46	1.46	78.55
Aug-16	48,935	66,698	66,698	0	3	0.0000	8	0	66,698	1.36	1.36	78.47
Sep-16	48,674	82,081	69,278	12,803	53	243.6988	68	3,768	85,849	1.69	1.76	78.58
Oct-16	48,654	195,780	69,278	126,502	324	390.7269	309	(5,767)	190,012	4.02	3.91	78.24
Nov-16	49,037	365,343	69,278	296,065	589	502.8390	647	29,272	394,615	7.45	8.05	78.32
Dec-16	50,219	675,065	69,278	605,787	973	622.8528	895	(48,334)	626,731	13.44	12.48	79.48
Jan-17	50,603	750,354	69,278	681,077	961	708.7627	1,069	76,591	826,945	14.83	16.34	80.54
Feb-17	50,556	573,885	69,278	504,608	719	702.2587	881	114,082	687,968	11.35	13.61	80.30
Mar-17	50,832	650,253	69,278	580,975	879	660.5964	749	(86,188)	564,064	12.79	11.10	79.98

UGI Utilities, Inc. - Gas Division
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Apr-17	50,931	240,310	69,278	171,032	264	647.5644	410	94,469	334,779	4.72	6.57	80.79
May-17	52,020	160,137	69,278	90,859	205	442.7107	155	(22,239)	137,898	3.08	2.65	80.77
Jun-17	51,976	74,808	69,278	5,531	33	166.2140	27	(1,043)	73,765	1.44	1.42	80.71
Jul-17	53,106	76,976	76,976	0	2	0.0000	0	0	76,976	1.45	1.45	80.70
Aug-17	54,163	75,610	75,610	0	19	0.0000	8	0	75,610	1.40	1.40	80.73
Sep-17	56,647	43,611	43,611	0	89	0.0000	68	0	43,611	0.77	0.77	79.74
Oct-17	59,641	117,487	76,293	41,194	227	181.1755	309	14,789	132,276	1.97	2.22	78.05
Nov-17	60,807	688,760	76,293	612,467	684	895.5539	647	(33,044)	655,716	11.33	10.78	80.79
Dec-17	66,212	1,078,481	76,293	1,002,188	1,087	921.6229	895	(177,336)	901,145	16.29	13.61	81.92
Jan-18	68,364	1,218,492	76,293	1,142,199	1,156	988.3791	1,069	(85,622)	1,132,870	17.82	16.57	82.15
Feb-18	68,522	794,715	76,293	718,423	775	927.4334	881	98,646	893,362	11.60	13.04	81.58
Mar-18	69,874	891,791	76,293	815,498	905	901.4745	749	(140,294)	751,497	12.76	10.76	81.23
Apr-18	71,254	564,679	76,293	488,386	573	852.6619	410	(138,795)	425,884	7.92	5.98	80.64
May-18	72,195	137,678	76,293	61,385	69	894.5091	155	77,264	214,942	1.91	2.98	80.96
Jun-18	71,932	127,047	76,293	50,754	29	873.5855	27	(1,562)	125,485	1.77	1.74	81.29
Jul-18	71,926	88,450	88,450	0	2	0.0000	0	0	88,450	1.23	1.23	81.07
Aug-18	72,549	86,905	86,905	0	2	0.0000	8	0	86,905	1.20	1.20	80.87
Sep-18	73,463	125,166	87,678	37,488	61	212.4372	68	1,436	126,601	1.70	1.72	81.82
Oct-18	73,696	354,681	87,678	267,004	370	721.6889	309	(44,002)	310,680	4.81	4.22	83.82
Nov-18	74,137	860,507	87,678	772,830	773	1,000.3046	647	(125,632)	734,875	11.61	9.91	82.95
Dec-18	76,256	988,132	87,678	900,454	886	1,016.3333	895	9,164	997,296	12.96	13.08	82.42
Jan-19	76,628	1,341,126	87,678	1,253,448	1,146	1,093.5441	1,069	(84,449)	1,256,676	17.50	16.40	82.25
Feb-19	76,446	1,091,967	87,678	1,004,289	904	1,110.8709	881	(25,612)	1,066,355	14.28	13.95	83.16
Mar-19	75,990	883,540	87,678	795,862	826	963.9796	749	(73,841)	809,698	11.63	10.66	83.06
Apr-19	75,260	331,836	87,678	244,158	319	764.4659	410	69,273	401,109	4.41	5.33	82.41
May-19	75,077	199,942	87,678	112,265	121	929.3933	155	31,791	231,734	2.66	3.09	82.52
Jun-19	75,146	116,475	87,678	28,797	25	846.9296	27	1,779	118,254	1.55	1.57	82.35
Jul-19	74,995	101,828	101,828	0	1	0.0000	0	0	101,828	1.36	1.36	82.48
Aug-19	74,851	89,446	89,446	0	2	0.0000	8	0	89,446	1.19	1.19	82.48
Sep-19	75,895	111,708	95,637	16,071	29	555.0710	68	21,674	133,382	1.47	1.76	82.51
Oct-19	76,033	250,892	95,637	155,255	266	583.6143	309	25,082	275,974	3.30	3.63	81.92
Nov-19	76,418	741,020	95,637	645,383	764	845.1167	647	(98,592)	642,428	9.70	8.41	80.42
Dec-19	77,332	1,236,628	95,637	1,140,991	923	1,236.1090	895	(34,673)	1,201,955	15.99	15.54	82.88
Jan-20	77,883	1,054,731	95,637	959,094	916	1,047.4705	1,069	160,652	1,215,383	13.54	15.61	82.09
Feb-20	78,311	851,415	95,637	755,778	822	919.4794	909	80,029	931,444	10.87	11.89	80.03
Mar-20	79,541	623,265	95,637	527,628	595	887.4032	749	137,037	760,302	7.84	9.56	78.94
Apr-20	80,169	627,083	95,637	531,445	488	1,089.0801	410	(84,922)	542,160	7.82	6.76	80.37
May-20	79,954	291,418	95,637	195,781	217	902.1175	155	(55,953)	235,466	3.64	2.95	80.23
Jun-20	79,563	170,322	95,637	74,685	13	995.5988	27	13,782	184,104	2.14	2.31	80.97
Jul-20	78,858	118,004	118,004	0	0	0.0000	0	0	118,004	1.50	1.50	81.11
Aug-20	78,276	82,867	82,867	0	0	0.0000	8	0	82,867	1.06	1.06	80.97
Sep-20	77,632	151,435	100,435	51,000	88	580.9002	68	(11,499)	139,937	1.95	1.80	81.02
Oct-20	77,136	275,971	100,435	175,536	309	568.0778	309	0	275,971	3.58	3.58	80.96
Nov-20	77,491	668,895	100,435	568,460	507	1,121.2223	647	156,971	825,866	8.63	10.66	83.22
Dec-20	77,815	998,469	100,435	898,034	940	955.3552	895	(42,991)	955,478	12.83	12.28	79.95
Jan-21	78,522	1,235,048	100,435	1,134,613	1,025	1,106.9395	1,069	48,705	1,283,754	15.73	16.35	80.70
Feb-21	78,025	1,171,466	100,435	1,071,031	969	1,105.2953	881	(97,266)	1,074,200	15.01	13.77	82.57
Mar-21	77,392	760,266	100,435	659,831	649	1,016.6881	749	101,669	861,935	9.82	11.14	84.15
Apr-21	76,480	423,331	100,435	322,896	388	832.2052	410	18,309	441,639	5.54	5.77	83.16
May-21	75,683	223,835	100,435	123,400	204	604.9000	155	(29,640)	194,195	2.96	2.57	82.78
Jun-21	74,733	113,406	100,435	12,971	12	718.5526	27	10,778	124,184	1.52	1.66	82.13
Jul-21	74,169	107,937	107,937	0	0	0.0000	0	0	107,937	1.46	1.46	82.09
Aug-21	73,677	105,994	105,994	0	0	0.0000	8	0	105,994	1.44	1.44	82.47
Sep-21	73,505	100,869	100,869	0	53	0.0000	68	0	100,869	1.37	1.37	82.04

UGI Utilities, Inc. - Gas Division
Residential Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-21	73,757	183,606	106,965	76,641	183	418.8007	309	52,769	236,375	2.49	3.20	81.66
Nov-21	73,966	759,774	106,965	652,809	720	906.6790	647	(66,188)	693,587	10.27	9.38	80.38
Dec-21	74,099	847,877	106,965	740,912	759	976.1690	895	132,759	980,636	11.44	13.23	81.34
Jan-22	74,161	1,408,974	106,965	1,302,009	1,219	1,068.0959	1,069	(160,214)	1,248,760	19.00	16.84	81.83
Feb-22	74,018	983,772	106,965	876,807	867	1,011.3115	881	14,158	997,931	13.29	13.48	81.54
Mar-22	74,229	730,832	106,965	623,866	674	925.6176	749	69,421	800,253	9.85	10.78	81.19
Apr-22	74,251	465,489	106,965	358,524	450	796.7193	410	(31,869)	433,620	6.27	5.84	81.25
May-22	73,827	182,959	106,965	75,994	94	808.4460	155	49,315	232,274	2.48	3.15	81.83
Jun-22	73,275	120,590	106,965	13,625	6	802.5826	27	16,854	137,444	1.65	1.88	82.05
Jul-22	73,123	95,663	95,663	0	0	0.0000	0	0	95,663	1.31	1.31	81.90
Aug-22	72,646	80,345	80,345	0	0	0.0000	8	0	80,345	1.11	1.11	81.57
Sep-22	72,117	131,823	88,004	43,819	81	540.9725	68	(7,033)	124,790	1.83	1.73	81.92
Oct-22	71,975	314,687	88,004	226,684	378	599.6924	309	(41,379)	273,309	4.37	3.80	82.52
Nov-22	71,474	613,092	88,004	525,089	583	900.6668	647	57,643	670,735	8.58	9.38	82.52
Dec-22	70,954	1,028,737	88,004	940,733	964	975.8640	895	(67,335)	961,402	14.50	13.55	82.84
Jan-23	70,939	871,759	88,004	783,755	820	955.7986	1,069	237,994	1,109,752	12.29	15.64	81.64
Feb-23	71,127	865,578	88,004	777,574	748	1,039.5377	881	138,259	1,003,836	12.17	14.11	82.28
Mar-23	73,494	771,022	88,004	683,018	734	930.5424	749	13,958	784,980	10.49	10.68	82.18
Apr-23	74,811	316,186	88,004	228,183	311	733.7065	410	72,637	388,823	4.23	5.20	81.53
May-23	76,153	220,305	88,004	132,301	164	806.7128	155	(7,260)	213,044	2.89	2.80	81.18
Jun-23	77,137	118,329	88,004	30,325	21	770.2096	27	4,621	122,950	1.53	1.59	80.90
Jul-23	77,798	101,296	101,296	0	0	0.0000	0	0	101,296	1.30	1.30	80.90
Aug-23	78,181	116,048	116,048	0	1	0.0000	8	0	116,048	1.48	1.48	81.27
Sep-23	78,771	119,807	108,672	11,135	71	156.8284	68	(470)	119,336	1.52	1.51	81.06
Oct-23	79,731	292,607	108,672	183,936	289	636.4553	309	12,729	305,336	3.67	3.83	81.09
Nov-23	80,755	742,887	108,672	634,215	678	935.4203	647	(28,998)	713,889	9.20	8.84	80.55
Dec-23	81,661	951,423	108,672	842,751	756	1,114.7502	895	154,950	1,106,373	11.65	13.55	80.55
Jan-24	80,531	1,217,026	108,672	1,108,354	985	1,125.2325	1,069	94,520	1,311,545	15.11	16.29	81.19
Feb-24	79,432	953,681	108,672	845,009	815	1,036.8207	909	97,461	1,051,142	12.01	13.23	80.31
Mar-24	78,473	701,739	108,672	593,067	603	983.5281	749	143,595	845,334	8.94	10.77	80.40
Apr-24	77,666	403,817	108,672	295,145	341	865.5283	410	59,721	463,538	5.20	5.97	81.17
May-24	76,905	172,386	108,672	63,714	95	670.6733	155	40,240	212,626	2.24	2.76	81.14
Jun-24	76,460	120,595	108,672	11,923	4	768.1008	27	17,666	138,261	1.58	1.81	81.35
Jul-24	76,247	105,954	105,954	0	0	0.0000	0	0	105,954	1.39	1.39	81.44
Aug-24	75,885	103,008	103,008	0	12	0.0000	8	0	103,008	1.36	1.36	81.31
Sep-24	75,897	86,968	86,968	0	35	0.0000	68	0	86,968	1.15	1.15	80.94
Oct-24	76,041	264,299	104,481	159,818	278	574.8855	309	17,821	282,120	3.48	3.71	80.82
Nov-24	76,196	556,635	104,481	452,154	562	804.5450	647	68,386	625,021	7.31	8.20	80.19
Dec-24	76,474	1,098,406	104,481	993,926	957	1,038.5847	895	(64,392)	1,034,014	14.36	13.52	80.16
Jan-25	77,603	1,436,910	104,481	1,332,429	1216	1,095.7473	1,069	(161,075)	1,275,835	18.52	16.44	80.31
Feb-25	77,873	1,127,665	104,481	1,023,184	941	1,087.3369	881	(65,240)	1,062,425	14.48	13.64	80.72
Mar-25	78,121	681,377	104,481	576,897	604	955.1268	749	138,493	819,871	8.72	10.49	80.45
Apr-25	77,986	408,749	104,481	304,268	359	847.5431	410	43,225	451,973	5.24	5.80	80.27
May-25	77,778	180,772	104,481	76,291	160	476.8217	155	(2,384)	178,388	2.32	2.29	79.80
Jun-25	77,888	109,214	104,481	4,733	20	236.6632	27	1,657	110,871	1.40	1.42	79.42
Jul-25	77,953	102,462	102,462	0	0	0.0000	0	0	102,462	1.31	1.31	79.34
Aug-25	78,332	108,699	108,699	0	24	0.0000	8	0	108,699	1.39	1.39	79.37
Sep-25	78,652	95,565	95,565	0	17	0.0000	68	0	95,565	1.22	1.22	79.44

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	60,479	75,992	58,377	17,614	455	38.6764	309	(5,663)	70,328	1.26	1.16	
Nov-03	60,524	94,163	58,377	35,786	574	62.3519	647	4,556	98,719	1.56	1.63	
Dec-03	60,528	116,210	58,377	57,833	999	57.8730	895	(6,036)	110,173	1.92	1.82	
Jan-04	60,363	131,202	58,377	72,825	1,357	53.6656	1,069	(15,456)	115,746	2.17	1.92	
Feb-04	60,182	126,651	58,377	68,274	983	69.4276	909	(5,164)	121,487	2.10	2.02	
Mar-04	59,985	107,861	58,377	49,484	736	67.2686	749	900	108,761	1.80	1.81	
Apr-04	60,024	89,994	58,377	31,617	438	72.1753	410	(2,025)	87,969	1.50	1.47	
May-04	59,867	80,201	58,377	21,824	97	69.7219	155	4,025	84,226	1.34	1.41	
Jun-04	59,542	60,330	58,377	1,953	52	37.5770	27	(938)	59,392	1.01	1.00	
Jul-04	59,332	58,742	58,742	0	1	0.0000	0	0	58,742	0.99	0.99	
Aug-04	59,200	58,012	58,012	0	21	0.0000	8	0	58,012	0.98	0.98	
Sep-04	59,312	62,495	58,377	4,118	59	69.8401	68	631	63,126	1.05	1.06	17.27
Oct-04	59,373	73,457	58,377	15,080	416	36.2382	309	(3,882)	69,575	1.24	1.17	17.28
Nov-04	59,321	90,718	58,377	32,341	627	51.5949	647	1,041	91,759	1.53	1.55	17.19
Dec-04	59,331	109,260	58,377	50,883	1,005	50.6255	895	(5,573)	103,687	1.84	1.75	17.12
Jan-05	59,194	128,020	58,377	69,643	1,217	57.2217	1,069	(8,473)	119,547	2.16	2.02	17.22
Feb-05	59,055	116,874	58,377	58,497	939	62.3086	881	(3,603)	113,271	1.98	1.92	17.12
Mar-05	58,896	116,862	58,377	58,485	942	62.0796	749	(11,988)	104,875	1.98	1.78	17.09
Apr-05	58,666	95,615	58,377	37,238	377	98.8046	410	3,272	98,887	1.63	1.69	17.31
May-05	58,463	74,733	58,377	16,356	268	61.0222	155	(6,897)	67,836	1.28	1.16	17.06
Jun-05	58,180	61,479	61,479	0	16	0.0000	27	0	61,479	1.06	1.06	17.12
Jul-05	57,849	58,179	58,179	0	0	0.0000	0	0	58,179	1.01	1.01	17.14
Aug-05	57,626	50,028	50,028	0	1	0.0000	8	0	50,028	0.87	0.87	17.03
Sep-05	57,440	52,428	52,428	0	35	0.0000	68	0	52,428	0.91	0.91	16.87
Oct-05	57,407	64,843	54,103	10,739	351	30.5862	309	(1,288)	63,554	1.13	1.11	16.81
Nov-05	57,529	84,302	54,103	30,199	600	50.3695	647	2,390	86,692	1.47	1.51	16.77
Dec-05	57,601	113,229	54,103	59,126	1,121	52.7432	895	(11,920)	101,308	1.97	1.76	16.78
Jan-06	57,451	126,594	54,103	72,491	890	81.4105	1,069	14,537	141,131	2.20	2.46	17.22
Feb-06	57,455	109,323	54,103	55,219	945	58.4294	881	(3,743)	105,580	1.90	1.84	17.14
Mar-06	57,477	107,146	54,103	53,043	775	68.4567	749	(1,769)	105,377	1.86	1.83	17.19
Apr-06	57,269	86,360	54,103	32,257	390	82.7125	410	1,656	88,015	1.51	1.54	17.04
May-06	56,982	72,253	54,103	18,150	184	98.4706	155	(2,887)	69,366	1.27	1.22	17.10
Jun-06	56,629	58,588	54,103	4,484	44	90.5916	27	(1,517)	57,070	1.03	1.01	17.05
Jul-06	56,349	54,535	54,535	0	1	0.0000	0	0	54,535	0.97	0.97	17.01
Aug-06	56,159	48,857	48,857	0	5	0.0000	8	0	48,857	0.87	0.87	17.01
Sep-06	56,089	54,106	51,696	2,410	123	19.6326	68	(1,075)	53,031	0.96	0.95	17.05
Oct-06	56,028	69,704	51,696	18,008	428	42.1178	309	(4,993)	64,710	1.24	1.15	17.09
Nov-06	56,036	86,335	51,696	34,639	552	62.7159	647	5,938	92,273	1.54	1.65	17.23
Dec-06	56,222	104,421	51,696	52,725	813	64.8337	895	5,301	109,722	1.86	1.95	17.43
Jan-07	56,071	109,790	51,696	58,094	997	58.2685	1,069	4,195	113,985	1.96	2.03	17.00
Feb-07	56,120	112,984	51,696	61,288	1,178	52.0428	881	(15,439)	97,546	2.01	1.74	16.90
Mar-07	56,165	125,501	51,696	73,805	824	89.5398	749	(6,740)	118,761	2.23	2.11	17.18
Apr-07	56,003	94,529	51,696	42,833	552	77.6426	410	(10,999)	83,529	1.69	1.49	17.14
May-07	55,767	72,575	51,696	20,879	142	83.5912	155	1,048	73,623	1.30	1.32	17.24
Jun-07	55,631	53,321	51,696	1,625	23	70.9442	27	291	53,612	0.96	0.96	17.20
Jul-07	55,279	50,624	50,624	0	13	0.0000	0	0	50,624	0.92	0.92	17.15
Aug-07	54,825	48,575	48,575	0	22	0.0000	8	0	48,575	0.89	0.89	17.16
Sep-07	54,608	54,287	49,599	4,688	72	64.9721	68	(270)	54,018	0.99	0.99	17.21
Oct-07	54,605	60,897	49,599	11,297	222	50.8413	309	4,413	65,309	1.12	1.20	17.25
Nov-07	54,779	77,824	49,599	28,225	739	38.1679	647	(3,530)	74,294	1.42	1.36	16.96
Dec-07	54,878	119,283	49,599	69,684	1,006	69.2578	895	(7,698)	111,585	2.17	2.03	17.04
Jan-08	54,618	131,264	49,599	81,665	1,051	77.7298	1,069	1,428	132,693	2.40	2.43	17.43
Feb-08	54,640	117,414	49,599	67,815	975	69.5634	909	(4,582)	112,833	2.15	2.07	17.76
Mar-08	54,663	113,204	49,599	63,604	819	77.7029	749	(5,405)	107,799	2.07	1.97	17.62

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-08	54,427	83,287	49,599	33,687	371	90.8179	410	3,548	86,835	1.53	1.60	17.72
May-08	54,197	65,804	49,599	16,204	275	58.9157	155	(7,072)	58,731	1.21	1.08	17.49
Jun-08	53,805	57,473	49,599	7,874	18	74.8668	27	678	58,152	1.07	1.08	17.60
Jul-08	53,302	48,435	48,435	0	0	0.0000	0	0	48,435	0.91	0.91	17.60
Aug-08	53,103	49,632	49,632	0	14	0.0000	8	0	49,632	0.93	0.93	17.64
Sep-08	52,929	53,622	49,033	4,589	80	57.0372	68	(711)	52,912	1.01	1.00	17.66
Oct-08	52,802	64,735	49,033	15,702	468	33.5608	309	(5,332)	59,404	1.23	1.13	17.58
Nov-08	52,751	93,794	49,033	44,760	721	62.0384	647	(4,622)	89,172	1.78	1.69	17.92
Dec-08	52,467	125,999	49,033	76,966	1,016	75.7218	895	(9,195)	116,804	2.40	2.23	18.11
Jan-09	52,048	131,018	49,033	81,984	1,292	63.4315	1,069	(14,176)	116,842	2.52	2.24	17.93
Feb-09	51,981	120,433	49,033	71,399	927	77.0263	881	(3,539)	116,893	2.32	2.25	18.11
Mar-09	52,010	104,573	49,033	55,539	774	71.7774	749	(1,778)	102,795	2.01	1.98	18.11
Apr-09	51,795	77,119	49,033	28,086	419	67.0013	410	(616)	76,504	1.49	1.48	18.00
May-09	51,566	65,828	49,033	16,795	179	93.7599	155	(2,262)	63,566	1.28	1.23	18.15
Jun-09	51,258	53,742	49,033	4,709	41	80.3806	27	(1,105)	52,636	1.05	1.03	18.09
Jul-09	51,119	52,435	52,435	0	15	0.0000	0	0	52,435	1.03	1.03	18.21
Aug-09	50,920	50,389	50,389	0	16	0.0000	8	0	50,389	0.99	0.99	18.26
Sep-09	50,625	51,048	51,048	0	118	0.0000	68	0	51,048	1.01	1.01	18.27
Oct-09	50,560	69,057	51,412	17,645	440	40.0918	309	(5,257)	63,800	1.37	1.26	18.41
Nov-09	50,533	86,170	51,412	34,758	571	60.8916	647	4,639	90,809	1.71	1.80	18.52
Dec-09	50,455	100,525	51,412	49,113	1,055	46.5410	895	(7,459)	93,066	1.99	1.84	18.13
Jan-10	49,942	124,178	51,412	72,766	1,157	62.8906	1,069	(5,536)	118,642	2.49	2.38	18.26
Feb-10	49,836	99,605	51,412	48,193	1,014	47.5204	881	(6,328)	93,278	2.00	1.87	17.89
Mar-10	49,780	94,320	51,412	42,907	627	68.4229	749	8,341	102,661	1.89	2.06	17.97
Apr-10	49,546	66,731	51,412	15,319	325	47.1597	410	4,016	70,748	1.35	1.43	17.92
May-10	49,174	61,319	51,412	9,907	153	64.6365	155	112	61,431	1.25	1.25	17.94
Jun-10	48,858	48,822	48,822	0	25	0.0000	27	0	48,822	1.00	1.00	17.91
Jul-10	48,667	43,594	43,594	0	4	0.0000	0	0	43,594	0.90	0.90	17.78
Aug-10	48,517	41,998	41,998	0	7	0.0000	8	0	41,998	0.87	0.87	17.66
Sep-10	48,462	47,279	42,796	4,483	67	67.3699	68	99	47,377	0.98	0.98	17.63
Oct-10	48,545	59,577	42,796	16,781	383	43.8310	309	(3,237)	56,340	1.23	1.16	17.53
Nov-10	48,569	76,929	42,796	34,133	669	51.0163	647	(1,126)	75,804	1.58	1.56	17.29
Dec-10	48,443	108,623	42,796	65,826	1,162	56.6379	895	(15,135)	93,487	2.24	1.93	17.38
Jan-11	47,991	116,030	42,796	73,234	1,251	58.5533	1,069	(10,640)	105,390	2.42	2.20	17.20
Feb-11	47,973	102,921	42,796	60,125	955	62.9293	881	(4,684)	98,237	2.15	2.05	17.37
Mar-11	48,012	90,052	42,796	47,256	836	56.5067	749	(4,933)	85,120	1.88	1.77	17.08
Apr-11	47,795	80,760	42,796	37,963	414	91.6680	410	(380)	80,380	1.69	1.68	17.34
May-11	47,451	59,439	42,796	16,643	125	74.0874	155	2,196	61,635	1.25	1.30	17.39
Jun-11	47,211	45,266	42,796	2,470	21	74.0874	27	413	45,679	0.96	0.97	17.36
Jul-11	47,000	42,827	42,827	0	1	0.0000	0	0	42,827	0.91	0.91	17.37
Aug-11	46,825	41,496	41,496	0	10	0.0000	8	0	41,496	0.89	0.89	17.39
Sep-11	46,821	46,490	42,162	4,328	74	58.5944	68	(343)	46,146	0.99	0.99	17.40
Oct-11	46,863	63,940	42,162	21,778	400	54.4971	309	(4,938)	59,002	1.36	1.26	17.50
Nov-11	46,739	78,579	42,162	36,417	559	65.1714	647	5,749	84,328	1.68	1.80	17.74
Dec-11	46,660	99,524	42,162	57,362	843	68.0440	895	3,537	103,061	2.13	2.21	18.02
Jan-12	46,313	111,029	42,162	68,867	1,002	68.7500	1,069	4,627	115,656	2.40	2.50	18.32
Feb-12	46,099	92,179	42,162	50,017	814	61.4421	909	5,834	98,013	2.00	2.13	18.40
Mar-12	46,063	84,177	42,162	42,015	487	86.2987	749	22,623	106,800	1.83	2.32	18.95
Apr-12	45,778	59,422	42,162	17,260	437	39.5195	410	(1,057)	58,365	1.30	1.27	18.54
May-12	45,498	52,682	42,162	10,520	73	62.9091	155	5,174	57,855	1.16	1.27	18.51
Jun-12	45,250	43,552	42,162	1,390	39	35.9558	27	(419)	43,133	0.96	0.95	18.50
Jul-12	45,146	38,946	38,946	0	1	0.0000	0	0	38,946	0.86	0.86	18.45
Aug-12	45,016	41,664	41,664	0	7	0.0000	8	0	41,664	0.93	0.93	18.49
Sep-12	45,078	41,582	40,305	1,278	110	11.6046	68	(488)	41,094	0.92	0.91	18.41

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	45,119	61,472	40,305	21,167	335	63.0949	309	(1,671)	59,801	1.36	1.33	18.48
Nov-12	44,978	81,363	40,305	41,058	785	52.3323	647	(7,199)	74,164	1.81	1.65	18.32
Dec-12	44,632	108,354	40,305	68,049	853	79.7350	895	3,314	111,668	2.43	2.50	18.62
Jan-13	44,267	117,188	40,305	76,883	1,047	73.4371	1,069	1,621	118,809	2.65	2.68	18.80
Feb-13	44,136	112,723	40,305	72,418	974	74.3366	881	(6,927)	105,795	2.55	2.40	19.08
Mar-13	44,066	102,359	40,305	62,054	884	70.2348	749	(9,448)	92,911	2.32	2.11	18.87
Apr-13	43,816	83,489	40,305	43,184	427	72.2857	410	(1,211)	82,278	1.91	1.88	19.47
May-13	43,652	53,264	40,305	12,959	178	72.6502	155	(1,698)	51,566	1.22	1.18	19.38
Jun-13	43,406	43,584	40,305	3,279	21	72.4680	27	436	44,021	1.00	1.01	19.44
Jul-13	43,256	38,466	38,466	0	4	0.0000	0	0	38,466	0.89	0.89	19.47
Aug-13	43,180	40,046	40,046	0	12	0.0000	8	0	40,046	0.93	0.93	19.47
Sep-13	43,158	43,708	39,256	4,452	143	31.2063	68	(2,330)	41,378	1.01	0.96	19.51
Oct-13	43,210	59,593	39,256	20,338	327	62.1257	309	(1,141)	58,453	1.38	1.35	19.54
Nov-13	43,087	82,899	39,256	43,643	773	56.4685	647	(7,108)	75,791	1.92	1.76	19.65
Dec-13	42,228	116,199	39,256	76,943	1,012	76.0402	895	(8,887)	107,312	2.75	2.54	19.69
Jan-14	41,379	127,169	39,256	87,913	1,310	67.1014	1,069	(16,182)	110,987	3.07	2.68	19.69
Feb-14	41,184	115,083	39,256	75,827	1,114	68.0702	881	(15,857)	99,226	2.79	2.41	19.70
Mar-14	41,038	107,381	39,256	68,125	976	69.7752	749	(15,864)	91,517	2.62	2.23	19.82
Apr-14	40,741	71,256	39,256	32,000	467	68.5813	410	(3,882)	67,374	1.75	1.65	19.60
May-14	40,538	53,579	39,256	14,323	152	69.1783	155	176	53,755	1.32	1.33	19.74
Jun-14	40,262	39,805	39,805	0	14	0.0000	27	0	39,805	0.99	0.99	19.72
Jul-14	40,102	37,650	37,650	0	10	0.0000	0	0	37,650	0.94	0.94	19.77
Aug-14	39,939	39,476	39,476	0	13	0.0000	8	0	39,476	0.99	0.99	19.83
Sep-14	39,971	38,299	38,299	0	98	0.0000	68	0	38,299	0.96	0.96	19.83
Oct-14	40,073	53,257	38,563	14,694	303	48.5386	309	304	53,561	1.33	1.34	19.81
Nov-14	40,076	81,006	38,563	42,443	759	55.9237	647	(6,261)	74,746	2.02	1.87	19.92
Dec-14	39,411	105,661	38,563	67,098	909	73.7968	895	(1,050)	104,611	2.68	2.65	20.03
Jan-15	38,956	117,426	38,563	78,863	1,231	64.0689	1,069	(10,373)	107,053	3.01	2.75	20.10
Feb-15	38,863	114,470	38,563	75,907	1,275	59.5317	881	(23,460)	91,010	2.95	2.34	20.03
Mar-15	38,765	111,531	38,563	72,968	960	76.0105	749	(16,036)	95,495	2.88	2.46	20.26
Apr-15	38,540	66,078	38,563	27,515	403	68.2533	410	469	66,547	1.71	1.73	20.34
May-15	38,196	43,730	38,563	5,167	83	62.4103	155	4,506	48,237	1.14	1.26	20.27
Jun-15	37,920	35,566	35,566	0	32	0.0000	27	0	35,566	0.94	0.94	20.22
Jul-15	37,826	35,079	35,079	0	4	0.0000	0	0	35,079	0.93	0.93	20.21
Aug-15	37,760	34,143	34,143	0	6	0.0000	8	0	34,143	0.90	0.90	20.13
Sep-15	37,723	35,986	34,611	1,375	42	32.3938	68	828	36,814	0.95	0.98	20.14
Oct-15	37,865	52,398	34,611	17,787	378	47.0721	309	(3,242)	49,156	1.38	1.30	20.11
Nov-15	37,830	65,539	34,611	30,928	508	60.8471	647	8,440	73,979	1.73	1.96	20.20
Dec-15	37,587	75,741	34,611	41,130	625	65.8319	895	17,790	93,531	2.02	2.49	20.03
Jan-16	37,437	98,164	34,611	63,553	1,130	56.2563	1,069	(3,415)	94,749	2.62	2.53	19.81
Feb-16	37,255	97,246	34,611	62,635	936	66.9376	909	(1,789)	95,457	2.61	2.56	20.03
Mar-16	37,228	70,413	34,611	35,802	582	61.5463	749	10,296	80,709	1.89	2.17	19.74
Apr-16	36,977	54,662	34,611	20,051	468	42.8389	410	(2,487)	52,175	1.48	1.41	19.42
May-16	36,905	46,509	34,611	11,898	221	53.8657	155	(3,549)	42,960	1.26	1.16	19.32
Jun-16	36,494	35,614	34,611	1,002	25	40.4314	27	89	35,703	0.98	0.98	19.36
Jul-16	35,770	31,735	31,735	0	2	0.0000	0	0	31,735	0.89	0.89	19.32
Aug-16	35,684	29,315	29,315	0	3	0.0000	8	0	29,315	0.82	0.82	19.24
Sep-16	35,244	31,669	30,525	1,143	53	21.7637	68	337	32,005	0.90	0.91	19.17
Oct-16	35,331	42,070	30,525	11,545	324	35.6587	309	(526)	41,544	1.19	1.18	19.05
Nov-16	35,379	48,302	30,525	17,776	589	30.1917	647	1,758	50,059	1.37	1.41	18.51
Dec-16	35,223	69,057	30,525	38,532	973	39.6171	895	(3,074)	65,983	1.96	1.87	17.90
Jan-17	34,895	78,760	30,525	48,235	961	50.1955	1,069	5,424	84,184	2.26	2.41	17.78
Feb-17	34,832	61,723	30,525	31,198	719	43.4182	881	7,053	68,777	1.77	1.97	17.19
Mar-17	34,889	63,653	30,525	33,128	879	37.6680	749	(4,915)	58,739	1.82	1.68	16.70

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

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Apr-17	34,152	46,482	30,525	15,956	264	60.4147	410	8,814	55,295	1.36	1.62	16.91
May-17	33,676	36,467	30,525	5,942	205	28.9528	155	(1,454)	35,013	1.08	1.04	16.79
Jun-17	33,548	30,810	30,525	285	33	8.5535	27	(54)	30,756	0.92	0.92	16.73
Jul-17	33,451	31,371	31,371	0	2	0.0000	0	0	31,371	0.94	0.94	16.78
Aug-17	33,445	29,228	29,228	0	19	0.0000	8	0	29,228	0.87	0.87	16.83
Sep-17	33,305	22,249	22,249	0	89	0.0000	68	0	22,249	0.67	0.67	16.59
Oct-17	33,385	47,968	30,299	17,668	227	28.2328	309	2,305	50,272	1.44	1.51	16.92
Nov-17	33,512	42,171	30,299	11,872	684	17.3592	647	(641)	41,531	1.26	1.24	16.74
Dec-17	33,648	72,825	30,299	42,525	1,087	39.1065	895	(7,525)	65,300	2.16	1.94	16.81
Jan-18	33,094	83,330	30,299	53,031	1,156	45.8893	1,069	(3,975)	79,355	2.52	2.40	16.80
Feb-18	32,119	53,749	30,299	23,449	775	30.2713	881	3,220	56,968	1.67	1.77	16.60
Mar-18	31,999	50,194	30,299	19,894	905	21.9919	749	(3,423)	46,771	1.57	1.46	16.37
Apr-18	31,887	44,861	30,299	14,561	573	25.4223	410	(4,138)	40,723	1.41	1.28	16.03
May-18	31,808	29,831	29,831	0	69	0.0000	155	0	29,831	0.94	0.94	15.93
Jun-18	31,770	30,283	30,283	0	29	0.0000	27	0	30,283	0.95	0.95	15.97
Jul-18	31,674	23,704	23,704	0	2	0.0000	0	0	23,704	0.75	0.75	15.78
Aug-18	31,572	21,088	21,088	0	2	0.0000	8	0	21,088	0.67	0.67	15.57
Sep-18	31,538	28,742	22,396	6,345	61	24.9983	68	169	28,911	0.91	0.92	15.82
Oct-18	31,508	39,854	22,396	17,457	370	47.1862	309	(2,877)	36,977	1.26	1.17	15.49
Nov-18	31,685	50,068	22,396	27,671	773	35.8161	647	(4,498)	45,569	1.58	1.44	15.69
Dec-18	31,763	64,627	22,396	42,231	886	47.6655	895	430	65,057	2.03	2.05	15.79
Jan-19	31,728	72,933	22,396	50,537	1,146	44.0899	1,069	(3,405)	69,528	2.30	2.19	15.59
Feb-19	30,638	64,452	22,396	42,056	904	46.5192	881	(1,073)	63,380	2.10	2.07	15.88
Mar-19	30,501	51,834	22,396	29,438	826	35.6562	749	(2,731)	49,103	1.70	1.61	16.03
Apr-19	30,501	34,080	22,396	11,683	319	36.5808	410	3,315	37,394	1.12	1.23	15.98
May-19	30,374	32,421	22,396	10,025	121	36.1185	155	1,235	33,657	1.07	1.11	16.15
Jun-19	30,335	27,056	22,396	4,659	25	36.1185	27	76	27,131	0.89	0.89	16.09
Jul-19	30,289	22,809	22,809	0	1	0.0000	0	0	22,809	0.75	0.75	16.10
Aug-19	30,225	22,813	22,813	0	2	0.0000	8	0	22,813	0.75	0.75	16.18
Sep-19	30,246	21,744	21,744	0	29	0.0000	68	0	21,744	0.72	0.72	15.99
Oct-19	30,239	31,625	22,811	8,814	266	33.1336	309	1,424	33,049	1.05	1.09	15.90
Nov-19	30,375	42,482	22,811	19,671	764	25.7588	647	(3,005)	39,477	1.40	1.30	15.77
Dec-19	30,385	68,199	22,811	45,388	923	49.1716	895	(1,379)	66,819	2.24	2.20	15.92
Jan-20	30,116	65,048	22,811	42,237	916	46.1294	1,069	7,075	72,123	2.16	2.39	16.12
Feb-20	29,884	48,258	22,811	25,447	822	30.9588	909	2,695	50,952	1.61	1.71	15.76
Mar-20	29,677	39,590	22,811	16,780	595	28.2213	749	4,358	43,949	1.33	1.48	15.63
Apr-20	29,660	44,972	22,811	22,162	488	45.4154	410	(3,541)	41,431	1.52	1.40	15.80
May-20	29,634	30,467	22,811	7,656	217	35.2787	155	(2,188)	28,279	1.03	0.95	15.64
Jun-20	29,649	28,965	22,811	6,154	13	40.3471	27	559	29,524	0.98	1.00	15.75
Jul-20	29,567	25,240	25,240	0	0	0.0000	0	0	25,240	0.85	0.85	15.85
Aug-20	29,526	16,604	16,604	0	0	0.0000	8	0	16,604	0.56	0.56	15.65
Sep-20	29,515	28,532	20,922	7,610	88	43.1991	68	(855)	27,677	0.97	0.94	15.87
Oct-20	29,575	35,644	22,811	12,833	309	41.5321	309	0	35,644	1.21	1.21	15.99
Nov-20	29,665	45,558	22,811	22,747	507	44.8662	647	6,281	51,839	1.54	1.75	16.43
Dec-20	29,727	53,512	22,811	30,701	940	32.6606	895	(1,470)	52,042	1.80	1.75	15.98
Jan-21	29,320	69,076	22,811	46,265	1,025	45.1366	1,069	1,986	71,062	2.36	2.42	16.01
Feb-21	28,881	55,251	22,811	32,441	969	33.4785	881	(2,946)	52,305	1.91	1.81	16.12
Mar-21	28,445	52,939	22,811	30,129	649	46.4231	749	4,642	57,582	1.86	2.02	16.66
Apr-21	28,456	33,006	22,811	10,195	388	26.2762	410	578	33,584	1.16	1.18	16.45
May-21	28,414	24,956	22,811	2,146	204	10.5176	155	(515)	24,441	0.88	0.86	16.35
Jun-21	28,311	16,306	16,306	0	12	0.0000	27	0	16,306	0.58	0.58	15.93
Jul-21	28,261	22,655	22,655	0	0	0.0000	0	0	22,655	0.80	0.80	15.88
Aug-21	28,196	22,307	22,307	0	0	0.0000	8	0	22,307	0.79	0.79	16.11
Sep-21	28,152	22,063	22,063	0	53	0.0000	68	0	22,063	0.78	0.78	15.96

UGI Utilities, Inc. - Gas Division
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Oct-21	28,165	29,396	22,481	6,915	183	37.7865	309	4,761	34,157	1.04	1.21	15.96
Nov-21	28,239	45,138	22,481	22,657	720	31.4681	647	(2,297)	42,841	1.60	1.52	15.73
Dec-21	28,326	51,480	22,481	28,999	759	38.2068	895	5,196	56,676	1.82	2.00	15.98
Jan-22	28,178	65,305	22,481	42,824	1,219	35.1305	1,069	(5,270)	60,036	2.32	2.13	15.69
Feb-22	27,741	58,099	22,481	35,618	867	41.0821	881	575	58,675	2.09	2.12	15.99
Mar-22	27,373	37,735	22,481	15,254	674	22.6315	749	1,697	39,432	1.38	1.44	15.41
Apr-22	27,240	33,132	22,481	10,651	450	23.6681	410	(947)	32,185	1.22	1.18	15.41
May-22	27,155	20,614	20,614	0	94	0.0000	155	0	20,614	0.76	0.76	15.31
Jun-22	27,069	21,130	21,130	0	6	0.0000	27	0	21,130	0.78	0.78	15.51
Jul-22	26,939	19,751	19,751	0	0	0.0000	0	0	19,751	0.73	0.73	15.45
Aug-22	26,881	17,330	17,330	0	0	0.0000	8	0	17,330	0.64	0.64	15.30
Sep-22	26,786	25,677	18,540	7,136	81	34.1155	68	(444)	25,233	0.96	0.94	15.46
Oct-22	26,821	32,420	18,540	13,880	378	36.7192	309	(2,534)	29,887	1.21	1.11	15.36
Nov-22	26,904	36,912	18,540	18,371	583	31.5118	647	2,017	38,928	1.37	1.45	15.29
Dec-22	26,993	51,736	18,540	33,195	964	34.4350	895	(2,376)	49,360	1.92	1.83	15.12
Jan-23	26,876	59,706	18,540	41,166	820	50.2026	1,069	12,500	72,207	2.22	2.69	15.67
Feb-23	26,697	49,227	18,540	30,687	748	41.0249	881	5,456	54,683	1.84	2.05	15.61
Mar-23	26,396	42,688	18,540	24,148	734	32.8987	749	493	43,181	1.62	1.64	15.80
Apr-23	25,977	28,615	18,540	10,075	311	32.3956	410	3,207	31,823	1.10	1.23	15.85
May-23	25,891	25,081	18,540	6,541	164	39.8816	155	(359)	24,722	0.97	0.95	16.04
Jun-23	25,854	21,538	18,540	2,998	21	36.1386	27	217	21,755	0.83	0.84	16.10
Jul-23	25,758	18,068	18,068	0	0	0.0000	0	0	18,068	0.70	0.70	16.07
Aug-23	25,700	20,581	20,581	0	1	0.0000	8	0	20,581	0.80	0.80	16.23
Sep-23	25,688	17,410	17,410	0	71	0.0000	68	0	17,410	0.68	0.68	15.96
Oct-23	25,708	27,818	17,739	10,079	289	34.8762	309	698	28,516	1.08	1.11	15.96
Nov-23	25,815	34,354	17,739	16,615	678	24.5060	647	(760)	33,594	1.33	1.30	15.81
Dec-23	25,948	48,508	17,739	30,769	756	40.6994	895	5,657	54,165	1.87	2.09	16.07
Jan-24	26,032	53,855	17,739	36,116	985	36.6665	1,069	3,080	56,935	2.07	2.19	15.57
Feb-24	25,803	47,534	17,739	29,795	815	36.5578	909	3,436	50,970	1.84	1.98	15.50
Mar-24	25,636	39,937	17,739	22,198	603	36.8121	749	5,375	45,311	1.56	1.77	15.63
Apr-24	25,397	32,625	17,739	14,886	341	43.6538	410	3,012	35,637	1.28	1.40	15.81
May-24	25,172	26,426	17,739	8,687	95	40.2330	155	2,414	28,840	1.05	1.15	16.00
Jun-24	25,104	22,889	17,739	5,150	4	41.9434	27	965	23,854	0.91	0.95	16.11
Jul-24	24,924	18,483	18,483	0	0	0.0000	0	0	18,483	0.74	0.74	16.15
Aug-24	24,867	16,387	16,387	0	12	0.0000	8	0	16,387	0.66	0.66	16.01
Sep-24	24,851	15,880	15,880	0	35	0.0000	68	0	15,880	0.64	0.64	15.97
Oct-24	24,883	21,938	16,133	5,805	278	20.8810	309	647	22,586	0.88	0.91	15.77
Nov-24	24,977	29,861	16,133	13,727	562	24.4261	647	2,076	31,937	1.20	1.28	15.74
Dec-24	25,079	47,385	16,133	31,252	957	32.6559	895	(2,025)	45,360	1.89	1.81	15.46
Jan-25	25,122	64,566	16,133	48,432	1216	39.8293	1,069	(5,855)	58,711	2.57	2.34	15.61
Feb-25	24,939	56,308	16,133	40,175	941	42.6939	881	(2,562)	53,747	2.26	2.16	15.79
Mar-25	24,854	45,968	16,133	29,834	604	49.3944	749	7,162	53,130	1.85	2.14	16.16
Apr-25	24,616	31,114	16,133	14,980	359	41.7279	410	2,128	33,242	1.26	1.35	16.11
May-25	24,460	21,496	16,133	5,363	160	33.5187	155	(168)	21,329	0.88	0.87	15.84
Jun-25	24,429	23,674	16,133	7,541	20	37.6233	27	263	23,937	0.97	0.98	15.87
Jul-25	24,320	17,726	17,726	0	0	0.0000	0	0	17,726	0.73	0.73	15.85
Aug-25	24,194	17,452	17,452	0	24	0.0000	8	0	17,452	0.72	0.72	15.92
Sep-25	24,144	17,431	17,431	0	17	0.0000	68	0	17,431	0.72	0.72	16.00

* Baseload is the average of July and August sales

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Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	402	574	362	212	455	0.4647	309	(68)	506	1.43	1.26	
Nov-03	396	739	362	377	574	0.6564	647	48	787	1.87	1.99	
Dec-03	377	847	362	485	999	0.4852	895	(51)	796	2.25	2.11	
Jan-04	370	955	362	593	1,357	0.4368	1,069	(126)	829	2.58	2.24	
Feb-04	368	919	362	556	983	0.5659	909	(42)	877	2.50	2.38	
Mar-04	358	671	362	309	736	0.4194	749	6	676	1.87	1.89	
Apr-04	350	619	362	256	438	0.5854	410	(16)	602	1.77	1.72	
May-04	347	512	362	149	97	0.5024	155	29	541	1.47	1.56	
Jun-04	344	375	362	12	52	0.2377	27	(6)	369	1.09	1.07	
Jul-04	344	342	342	0	1	0.0000	0	0	342	0.99	0.99	
Aug-04	340	383	383	0	21	0.0000	8	0	383	1.13	1.13	
Sep-04	336	314	314	0	59	0.0000	68	0	314	0.93	0.93	19.27
Oct-04	334	484	362	122	416	0.2935	309	(31)	453	1.45	1.36	19.37
Nov-04	332	501	362	139	627	0.2215	647	4	505	1.51	1.52	18.91
Dec-04	324	714	362	351	1,005	0.3496	895	(38)	675	2.20	2.08	18.88
Jan-05	320	732	362	370	1,217	0.3041	1,069	(45)	687	2.29	2.15	18.78
Feb-05	317	678	362	315	939	0.3360	881	(19)	658	2.14	2.08	18.48
Mar-05	316	668	362	306	942	0.3243	749	(63)	605	2.11	1.91	18.50
Apr-05	314	541	362	179	377	0.4740	410	16	556	1.72	1.77	18.56
May-05	312	465	362	103	268	0.3826	155	(43)	421	1.49	1.35	18.35
Jun-05	312	288	288	0	16	0.0000	27	0	288	0.92	0.92	18.20
Jul-05	305	326	326	0	0	0.0000	0	0	326	1.07	1.07	18.27
Aug-05	300	255	255	0	1	0.0000	8	0	255	0.85	0.85	18.00
Sep-05	299	295	290	5	35	0.1378	68	5	299	0.99	1.00	18.06
Oct-05	298	335	290	45	351	0.1276	309	(5)	329	1.12	1.11	17.81
Nov-05	297	436	290	146	600	0.2440	647	12	448	1.47	1.51	17.80
Dec-05	294	569	290	279	1,121	0.2488	895	(56)	513	1.94	1.74	17.46
Jan-06	293	690	290	400	890	0.4494	1,069	80	770	2.36	2.63	17.94
Feb-06	287	545	290	255	945	0.2700	881	(17)	528	1.90	1.84	17.70
Mar-06	284	486	290	196	775	0.2532	749	(7)	480	1.71	1.69	17.48
Apr-06	345	486	290	196	390	0.5026	410	10	496	1.41	1.44	17.14
May-06	381	483	290	193	184	0.3779	155	(11)	472	1.27	1.24	17.03
Jun-06	391	380	290	90	44	0.3779	27	(6)	373	0.97	0.95	17.06
Jul-06	403	481	481	0	1	0.0000	0	0	481	1.19	1.19	17.19
Aug-06	395	290	290	0	5	0.0000	8	0	290	0.73	0.73	17.07
Sep-06	387	367	367	0	123	0.0000	68	0	367	0.95	0.95	17.02
Oct-06	383	476	385	91	428	0.2125	309	(25)	451	1.24	1.18	17.09
Nov-06	377	636	385	250	552	0.4535	647	43	679	1.69	1.80	17.38
Dec-06	374	711	385	325	813	0.4002	895	33	743	1.90	1.99	17.63
Jan-07	369	705	385	320	997	0.3209	1,069	23	728	1.91	1.97	16.97
Feb-07	366	727	385	341	1,178	0.2899	881	(86)	641	1.99	1.75	16.88
Mar-07	358	769	385	383	824	0.4650	749	(35)	734	2.15	2.05	17.24
Apr-07	375	670	385	284	552	0.5153	410	(73)	597	1.79	1.59	17.40
May-07	375	527	385	141	142	0.4901	155	6	533	1.40	1.42	17.58
Jun-07	371	328	328	0	23	0.0000	27	0	328	0.89	0.89	17.51
Jul-07	366	328	328	0	13	0.0000	0	0	328	0.90	0.90	17.21
Aug-07	360	278	278	0	22	0.0000	8	0	278	0.77	0.77	17.25
Sep-07	351	349	303	46	72	0.3659	68	(2)	348	1.00	0.99	17.29
Oct-07	347	415	303	112	222	0.5038	309	44	459	1.20	1.32	17.44
Nov-07	345	472	303	169	739	0.2279	647	(21)	451	1.37	1.31	16.95
Dec-07	336	719	303	416	1,006	0.4132	895	(46)	673	2.14	2.00	16.96
Jan-08	327	746	303	442	1,051	0.4210	1,069	8	753	2.28	2.30	17.29
Feb-08	318	642	303	338	975	0.3472	909	(23)	619	2.02	1.95	17.49
Mar-08	313	588	303	285	819	0.3480	749	(24)	564	1.88	1.80	17.24

UGI Utilities, Inc. - Gas Division
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Apr-08	305	455	303	152	371	0.4096	410	16	471	1.49	1.54	17.19
May-08	299	361	303	58	275	0.2114	155	(25)	336	1.21	1.12	16.90
Jun-08	292	296	296	0	18	0.0000	27	0	296	1.01	1.01	17.02
Jul-08	290	252	252	0	0	0.0000	0	0	252	0.87	0.87	17.00
Aug-08	289	267	267	0	14	0.0000	8	0	267	0.92	0.92	17.15
Sep-08	287	317	259	57	80	0.7140	68	(9)	308	1.10	1.07	17.23
Oct-08	362	450	259	191	468	0.4079	309	(65)	385	1.24	1.06	16.97
Nov-08	550	867	259	608	721	0.8425	647	(63)	804	1.58	1.46	17.13
Dec-08	607	1,535	259	1,276	1,016	1.2555	895	(152)	1,383	2.53	2.28	17.40
Jan-09	601	1,528	259	1,268	1,292	0.9813	1,069	(219)	1,308	2.54	2.18	17.27
Feb-09	590	1,426	259	1,167	927	1.2587	881	(58)	1,368	2.42	2.32	17.65
Mar-09	571	1,175	259	916	774	1.1839	749	(29)	1,146	2.06	2.01	17.85
Apr-09	561	955	259	696	419	1.6605	410	(15)	940	1.70	1.68	17.98
May-09	549	750	259	491	179	1.4222	155	(34)	715	1.37	1.30	18.16
Jun-09	529	598	259	339	41	1.4222	27	(20)	579	1.13	1.09	18.24
Jul-09	521	549	549	0	15	0.0000	0	0	549	1.05	1.05	18.43
Aug-09	490	529	529	0	16	0.0000	8	0	529	1.08	1.08	18.58
Sep-09	474	501	501	0	118	0.0000	68	0	501	1.06	1.06	18.57
Oct-09	453	698	539	160	440	0.3629	309	(48)	651	1.54	1.44	18.94
Nov-09	464	912	539	373	571	0.6541	647	50	962	1.97	2.07	19.55
Dec-09	453	1,064	539	525	1,055	0.4975	895	(80)	984	2.35	2.17	19.44
Jan-10	455	1,353	539	815	1,157	0.7040	1,069	(62)	1,291	2.97	2.84	20.11
Feb-10	460	1,142	539	603	1,014	0.5950	881	(79)	1,063	2.48	2.31	20.10
Mar-10	458	1,092	539	553	627	0.8818	749	108	1,199	2.38	2.62	20.71
Apr-10	459	702	539	163	325	0.5015	410	43	744	1.53	1.62	20.65
May-10	454	641	539	102	153	0.6661	155	1	642	1.41	1.41	20.76
Jun-10	443	519	519	0	25	0.0000	27	0	519	1.17	1.17	20.84
Jul-10	457	452	452	0	4	0.0000	0	0	452	0.99	0.99	20.78
Aug-10	448	435	435	0	7	0.0000	8	0	435	0.97	0.97	20.67
Sep-10	441	484	444	40	67	0.6057	68	1	485	1.10	1.10	20.72
Oct-10	477	674	444	230	383	0.6008	309	(44)	629	1.41	1.32	20.60
Nov-10	490	938	444	494	669	0.7388	647	(16)	922	1.91	1.88	20.41
Dec-10	510	1,596	444	1,152	1,162	0.9913	895	(265)	1,331	3.13	2.61	20.84
Jan-11	532	1,871	444	1,427	1,251	1.1409	1,069	(207)	1,663	3.52	3.13	21.13
Feb-11	530	1,617	444	1,173	955	1.2280	881	(91)	1,526	3.05	2.88	21.70
Mar-11	529	1,348	444	905	836	1.0816	749	(94)	1,254	2.55	2.37	21.45
Apr-11	523	1,157	444	713	414	1.7224	410	(7)	1,150	2.21	2.20	22.03
May-11	517	767	444	324	125	1.4020	155	42	809	1.48	1.56	22.18
Jun-11	515	578	444	134	21	1.4020	27	8	586	1.12	1.14	22.15
Jul-11	509	524	524	0	1	0.0000	0	0	524	1.03	1.03	22.19
Aug-11	507	532	532	0	10	0.0000	8	0	532	1.05	1.05	22.26
Sep-11	553	665	528	137	74	1.8589	68	(11)	654	1.20	1.18	22.35
Oct-11	652	1,115	528	588	400	1.4704	309	(133)	982	1.71	1.51	22.53
Nov-11	825	2,011	528	1,483	559	2.6542	647	234	2,245	2.44	2.72	23.37
Dec-11	1,079	3,387	528	2,860	843	3.3921	895	176	3,564	3.14	3.30	24.07
Jan-12	1,290	4,618	528	4,090	1,002	4.0829	1,069	275	4,892	3.58	3.79	24.73
Feb-12	1,358	4,092	528	3,564	814	4.3781	909	416	4,507	3.01	3.32	25.17
Mar-12	1,419	3,732	528	3,205	487	6.5823	749	1,726	5,458	2.63	3.85	26.65
Apr-12	1,512	2,683	528	2,155	437	4.9352	410	(132)	2,551	1.77	1.69	26.14
May-12	1,742	2,664	528	2,137	73	5.7587	155	474	3,138	1.53	1.80	26.37
Jun-12	1,916	2,288	528	1,761	39	5.7587	27	(67)	2,221	1.19	1.16	26.40
Jul-12	1,975	2,074	2,074	0	1	0.0000	0	0	2,074	1.05	1.05	26.42
Aug-12	2,288	2,433	2,433	0	7	0.0000	8	0	2,433	1.06	1.06	26.43
Sep-12	2,420	2,869	2,253	616	110	5.5941	68	(235)	2,634	1.19	1.09	26.34

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Oct-12	2,545	4,324	2,253	2,071	335	6.1721	309	(163)	4,161	1.70	1.63	26.47
Nov-12	2,651	5,989	2,253	3,736	785	4.7618	647	(655)	5,334	2.26	2.01	25.76
Dec-12	2,805	8,730	2,253	6,477	853	7.5889	895	315	9,045	3.11	3.22	25.68
Jan-13	3,018	9,900	2,253	7,646	1,047	7.3034	1,069	161	10,061	3.28	3.33	25.22
Feb-13	3,046	9,769	2,253	7,515	974	7.7146	881	(719)	9,050	3.21	2.97	24.87
Mar-13	3,093	8,921	2,253	6,667	884	7.5464	749	(1,015)	7,906	2.88	2.56	23.58
Apr-13	3,124	7,941	2,253	5,688	427	7.6305	410	(128)	7,813	2.54	2.50	24.40
May-13	3,150	4,934	2,253	2,680	178	7.6305	155	(178)	4,755	1.57	1.51	24.10
Jun-13	3,241	3,978	2,253	1,724	21	7.6305	27	46	4,024	1.23	1.24	24.19
Jul-13	3,306	3,488	3,488	0	4	0.0000	0	0	3,488	1.06	1.06	24.19
Aug-13	3,309	3,687	3,687	0	12	0.0000	8	0	3,687	1.11	1.11	24.24
Sep-13	3,395	4,110	3,588	522	143	3.6602	68	(273)	3,836	1.21	1.13	24.28
Oct-13	3,471	5,542	3,588	1,955	327	5.9705	309	(110)	5,432	1.60	1.57	24.21
Nov-13	3,652	8,274	3,588	4,687	773	6.0643	647	(763)	7,511	2.27	2.06	24.26
Dec-13	3,798	12,682	3,588	9,094	1,012	8.9873	895	(1,050)	11,631	3.34	3.06	24.10
Jan-14	3,821	15,651	3,588	12,063	1,310	9.2074	1,069	(2,220)	13,430	4.10	3.51	24.28
Feb-14	3,808	14,698	3,588	11,110	1,114	9.9736	881	(2,323)	12,374	3.86	3.25	24.56
Mar-14	3,771	13,353	3,588	9,766	976	10.0022	749	(2,274)	11,079	3.54	2.94	24.94
Apr-14	3,635	8,342	3,588	4,754	467	10.1885	410	(577)	7,765	2.29	2.14	24.57
May-14	3,576	5,915	3,588	2,327	152	15.2650	155	39	5,954	1.65	1.66	24.73
Jun-14	3,527	4,222	3,588	635	14	12.7268	27	171	4,393	1.20	1.25	24.73
Jul-14	3,483	3,480	3,480	0	10	0.0000	0	0	3,480	1.00	1.00	24.68
Aug-14	3,563	3,882	3,882	0	13	0.0000	8	0	3,882	1.09	1.09	24.65
Sep-14	3,597	4,101	3,681	420	98	4.2728	68	(130)	3,971	1.14	1.10	24.63
Oct-14	3,653	5,698	3,681	2,017	303	6.6632	309	42	5,740	1.56	1.57	24.63
Nov-14	3,732	9,331	3,681	5,650	759	7.4448	647	(833)	8,498	2.50	2.28	24.85
Dec-14	3,714	11,823	3,681	8,142	909	8.9548	895	(127)	11,695	3.18	3.15	24.94
Jan-15	3,782	13,621	3,681	9,940	1,231	8.0758	1,069	(1,307)	12,314	3.60	3.26	24.68
Feb-15	3,848	13,671	3,681	9,990	1,275	7.8348	881	(3,087)	10,583	3.55	2.75	24.18
Mar-15	3,903	13,752	3,681	10,071	960	10.4912	749	(2,213)	11,539	3.52	2.96	24.20
Apr-15	3,872	8,145	3,681	4,464	403	11.0728	410	76	8,221	2.10	2.12	24.19
May-15	3,907	5,288	3,681	1,607	83	19.4151	155	1,402	6,690	1.35	1.71	24.23
Jun-15	3,903	4,205	3,681	524	32	16.1746	27	(88)	4,118	1.08	1.05	24.04
Jul-15	3,873	4,018	4,018	0	4	0.0000	0	0	4,018	1.04	1.04	24.08
Aug-15	3,833	3,890	3,890	0	6	0.0000	8	0	3,890	1.01	1.01	24.01
Sep-15	3,829	3,948	3,948	0	42	0.0000	68	0	3,948	1.03	1.03	23.93
Oct-15	3,874	5,905	3,954	1,951	378	5.1629	309	(356)	5,549	1.52	1.43	23.80
Nov-15	3,895	8,586	3,954	4,632	508	9.1138	647	1,264	9,850	2.20	2.53	24.05
Dec-15	3,966	9,585	3,954	5,631	625	9.0136	895	2,436	12,021	2.42	3.03	23.93
Jan-16	3,976	12,204	3,954	8,250	1,130	7.3032	1,069	(443)	11,761	3.07	2.96	23.63
Feb-16	3,977	12,463	3,954	8,510	936	9.0941	909	(243)	12,220	3.13	3.07	23.95
Mar-16	4,006	9,003	3,954	5,049	582	8.6798	749	1,452	10,455	2.25	2.61	23.61
Apr-16	4,027	6,813	3,954	2,859	468	6.1087	410	(355)	6,458	1.69	1.60	23.09
May-16	4,132	5,979	3,954	2,025	221	9.1689	155	(604)	5,375	1.45	1.30	22.68
Jun-16	3,986	4,342	3,954	389	25	7.6388	27	17	4,359	1.09	1.09	22.71
Jul-16	3,964	3,823	3,823	0	2	0.0000	0	0	3,823	0.96	0.96	22.64
Aug-16	3,941	3,547	3,547	0	3	0.0000	8	0	3,547	0.90	0.90	22.53
Sep-16	3,914	3,781	3,685	96	53	1.8266	68	28	3,809	0.97	0.97	22.47
Oct-16	3,905	4,977	3,685	1,292	324	3.9893	309	(59)	4,918	1.27	1.26	22.30
Nov-16	3,931	6,035	3,685	2,350	589	3.9916	647	232	6,268	1.54	1.59	21.36
Dec-16	3,995	8,095	3,685	4,410	973	4.5345	895	(352)	7,744	2.03	1.94	20.27
Jan-17	3,968	9,696	3,685	6,011	961	6.2549	1,069	676	10,372	2.44	2.61	19.92
Feb-17	3,971	7,566	3,685	3,881	719	5.4009	881	877	8,443	1.91	2.13	18.98
Mar-17	3,992	7,681	3,685	3,995	879	4.5430	749	(593)	7,088	1.92	1.78	18.14

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-17	3,860	5,865	3,685	2,179	264	8.2517	410	1,204	7,068	1.52	1.83	18.37
May-17	3,885	4,768	3,685	1,083	205	5.2772	155	(265)	4,503	1.23	1.16	18.23
Jun-17	3,882	4,036	3,685	351	33	6.7645	27	(42)	3,993	1.04	1.03	18.16
Jul-17	3,917	3,755	3,755	0	2	0.0000	0	0	3,755	0.96	0.96	18.16
Aug-17	3,952	3,378	3,378	0	19	0.0000	8	0	3,378	0.85	0.85	18.11
Sep-17	3,991	1,854	1,854	0	89	0.0000	68	0	1,854	0.46	0.46	17.60
Oct-17	4,122	4,667	3,566	1,101	227	4.8403	309	395	5,062	1.13	1.23	17.57
Nov-17	4,151	9,357	3,566	5,790	684	8.4667	647	(312)	9,044	2.25	2.18	18.16
Dec-17	4,330	9,712	3,566	6,145	1,087	5.6512	895	(1,087)	8,624	2.24	1.99	18.21
Jan-18	4,340	11,682	3,566	8,115	1,156	7.0225	1,069	(608)	11,073	2.69	2.55	18.15
Feb-18	4,191	7,632	3,566	4,065	775	5.2481	881	558	8,190	1.82	1.95	17.98
Mar-18	4,216	7,477	3,566	3,910	905	4.3227	749	(673)	6,804	1.77	1.61	17.82
Apr-18	4,237	6,669	3,566	3,103	573	5.4168	410	(882)	5,787	1.57	1.37	17.35
May-18	4,293	4,555	3,566	988	69	4.8697	155	421	4,975	1.06	1.16	17.35
Jun-18	4,262	4,753	3,566	1,187	29	4.8697	27	(9)	4,745	1.12	1.11	17.43
Jul-18	4,248	4,909	4,909	0	2	0.0000	0	0	4,909	1.16	1.16	17.63
Aug-18	4,259	1,796	1,796	0	2	0.0000	8	0	1,796	0.42	0.42	17.20
Sep-18	4,311	4,760	3,353	1,407	61	1.8266	68	12	4,772	1.10	1.11	17.84
Oct-18	4,324	6,414	3,353	3,061	370	8.2744	309	(504)	5,910	1.48	1.37	17.98
Nov-18	4,336	7,639	3,353	4,286	773	5.5475	647	(697)	6,942	1.76	1.60	17.40
Dec-18	4,395	9,212	3,353	5,859	886	6.6135	895	60	9,272	2.10	2.11	17.52
Jan-19	4,384	10,402	3,353	7,049	1,146	6.1496	1,069	(475)	9,927	2.37	2.26	17.23
Feb-19	4,236	8,631	3,353	5,278	904	5.8386	881	(135)	8,497	2.04	2.01	17.28
Mar-19	4,217	7,129	3,353	3,777	826	4.5744	749	(350)	6,779	1.69	1.61	17.28
Apr-19	4,190	5,416	3,353	2,063	319	6.4590	410	585	6,001	1.29	1.43	17.34
May-19	4,168	5,289	3,353	1,936	121	5.5167	155	189	5,477	1.27	1.31	17.50
Jun-19	4,175	4,121	3,353	768	25	5.5167	27	12	4,133	0.99	0.99	17.38
Jul-19	4,149	3,545	3,545	0	1	0.0000	0	0	3,545	0.85	0.85	17.07
Aug-19	4,137	3,623	3,623	0	2	0.0000	8	0	3,623	0.88	0.88	17.53
Sep-19	4,167	3,129	3,129	0	29	0.0000	68	0	3,129	0.75	0.75	17.17
Oct-19	4,172	4,924	3,584	1,341	266	5.0392	309	217	5,141	1.18	1.23	17.04
Nov-19	4,186	6,335	3,584	2,751	764	3.6027	647	(420)	5,915	1.51	1.41	16.85
Dec-19	4,261	9,776	3,584	6,193	923	6.7088	895	(188)	9,588	2.29	2.25	16.99
Jan-20	4,248	9,198	3,584	5,614	916	6.1317	1,069	940	10,139	2.17	2.39	17.11
Feb-20	4,211	6,938	3,584	3,354	822	4.0806	909	355	7,293	1.65	1.73	16.84
Mar-20	4,224	5,578	3,584	1,994	595	3.3537	749	518	6,096	1.32	1.44	16.67
Apr-20	4,264	6,940	3,584	3,356	488	6.8769	410	(536)	6,403	1.63	1.50	16.74
May-20	4,238	4,457	3,584	873	217	4.0224	155	(249)	4,207	1.05	0.99	16.42
Jun-20	4,209	4,611	3,584	1,028	13	5.4496	27	75	4,687	1.10	1.11	16.55
Jul-20	4,156	3,771	3,771	0	0	0.0000	0	0	3,771	0.91	0.91	16.60
Aug-20	4,168	2,792	2,792	0	0	0.0000	8	0	2,792	0.67	0.67	16.39
Sep-20	4,148	4,701	3,282	1,419	88	6.9846	68	(138)	4,563	1.13	1.10	16.74
Oct-20	4,078	5,524	3,282	2,242	309	7.2570	309	0	5,524	1.35	1.35	16.86
Nov-20	4,066	6,685	3,282	3,403	507	6.7121	647	940	7,624	1.64	1.88	17.33
Dec-20	4,051	6,865	3,282	3,583	940	3.8119	895	(172)	6,693	1.69	1.65	16.73
Jan-21	3,987	8,942	3,282	5,660	1,025	5.5224	1,069	243	9,185	2.24	2.30	16.65
Feb-21	3,904	7,250	3,282	3,969	969	4.0957	881	(360)	6,890	1.86	1.76	16.68
Mar-21	3,828	7,028	3,282	3,746	649	5.7720	749	577	7,605	1.84	1.99	17.22
Apr-21	3,799	4,768	3,282	1,487	388	3.8314	410	84	4,852	1.26	1.28	17.00
May-21	3,782	3,588	3,282	306	204	1.5014	155	(74)	3,514	0.95	0.93	16.93
Jun-21	3,738	2,393	2,393	0	12	0.0000	27	0	2,393	0.64	0.64	16.46
Jul-21	3,720	3,281	3,281	0	0	0.0000	0	0	3,281	0.88	0.88	16.44
Aug-21	3,667	3,267	3,267	0	0	0.0000	8	0	3,267	0.89	0.89	16.66
Sep-21	3,640	3,210	3,210	0	53	0.0000	68	0	3,210	0.88	0.88	16.44

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-21	3,699	4,285	3,274	1,012	183	5.5279	309	697	4,982	1.16	1.35	16.43
Nov-21	3,737	6,332	3,274	3,059	720	4.2482	647	(310)	6,022	1.69	1.61	16.17
Dec-21	3,758	6,545	3,274	3,271	759	4.3097	895	586	7,131	1.74	1.90	16.41
Jan-22	3,774	8,277	3,274	5,004	1,219	4.1047	1,069	(616)	7,662	2.19	2.03	16.14
Feb-22	3,735	7,300	3,274	4,026	867	4.6439	881	65	7,365	1.95	1.97	16.35
Mar-22	3,711	5,348	3,274	2,074	674	3.0777	749	231	5,579	1.44	1.50	15.86
Apr-22	3,697	4,722	3,274	1,449	450	3.2193	410	(129)	4,594	1.28	1.24	15.83
May-22	3,699	3,119	3,119	0	94	0.0000	155	0	3,119	0.84	0.84	15.74
Jun-22	3,660	3,268	3,268	0	6	0.0000	27	0	3,268	0.89	0.89	15.99
Jul-22	3,646	2,988	2,988	0	0	0.0000	0	0	2,988	0.82	0.82	15.93
Aug-22	3,704	2,691	2,691	0	0	0.0000	8	0	2,691	0.73	0.73	15.77
Sep-22	3,695	3,996	2,840	1,156	81	5.0160	68	(65)	3,931	1.08	1.06	15.95
Oct-22	3,664	4,991	2,840	2,151	378	5.6913	309	(393)	4,598	1.36	1.25	15.86
Nov-22	3,676	5,370	2,840	2,531	583	4.3408	647	278	5,648	1.46	1.54	15.78
Dec-22	3,690	6,862	2,840	4,022	964	4.1722	895	(288)	6,574	1.86	1.78	15.67
Jan-23	3,646	7,773	2,840	4,933	820	6.0157	1,069	1,498	9,270	2.13	2.54	16.18
Feb-23	3,560	6,279	2,840	3,439	748	4.5977	881	611	6,890	1.76	1.94	16.14
Mar-23	3,553	5,622	2,840	2,783	734	3.7913	749	57	5,679	1.58	1.60	16.24
Apr-23	3,514	4,162	2,840	1,323	311	4.2529	410	421	4,583	1.18	1.30	16.30
May-23	3,563	3,920	2,840	1,080	164	6.5878	155	(59)	3,861	1.10	1.08	16.54
Jun-23	3,603	3,509	2,840	669	21	5.4203	27	33	3,541	0.97	0.98	16.63
Jul-23	3,637	2,958	2,958	0	0	0.0000	0	0	2,958	0.81	0.81	16.62
Aug-23	3,648	3,350	3,350	0	1	0.0000	8	0	3,350	0.92	0.92	16.82
Sep-23	3,687	2,969	2,969	0	71	0.0000	68	0	2,969	0.81	0.81	16.56
Oct-23	3,718	4,556	3,154	1,402	289	4.8529	309	97	4,653	1.23	1.25	16.55
Nov-23	3,755	5,267	3,154	2,113	678	3.1165	647	(97)	5,170	1.40	1.38	16.39
Dec-23	3,785	7,033	3,154	3,879	756	5.1313	895	713	7,746	1.86	2.05	16.66
Jan-24	3,800	7,636	3,154	4,482	985	4.5505	1,069	382	8,018	2.01	2.11	16.23
Feb-24	3,789	6,888	3,154	3,734	815	4.5820	909	431	7,319	1.82	1.93	16.22
Mar-24	3,756	6,174	3,154	3,020	603	5.0081	749	731	6,905	1.64	1.84	16.46
Apr-24	3,759	5,262	3,154	2,108	341	6.1826	410	427	5,689	1.40	1.51	16.67
May-24	3,730	4,471	3,154	1,317	95	5.5953	155	336	4,806	1.20	1.29	16.88
Jun-24	3,736	3,813	3,154	659	4	5.8890	27	135	3,949	1.02	1.06	16.95
Jul-24	3,727	3,902	3,902	0	0	0.0000	0	0	3,902	1.05	1.05	17.18
Aug-24	3,705	1,947	1,947	0	12	0.0000	8	0	1,947	0.53	0.53	16.79
Sep-24	3,682	2,601	2,601	0	35	0.0000	68	0	2,601	0.71	0.71	16.69
Oct-24	3,679	3,643	2,925	718	278	2.5820	309	80	3,723	0.99	1.01	16.45
Nov-24	3,698	4,789	2,925	1,864	562	3.3175	647	282	5,071	1.30	1.37	16.45
Dec-24	3,714	6,937	2,925	4,013	957	4.1929	895	(260)	6,677	1.87	1.80	16.20
Jan-25	3,732	9,088	2,925	6,163	1216	5.0683	1,069	(745)	8,343	2.44	2.24	16.32
Feb-25	3,732	7,886	2,925	4,961	941	5.2719	881	(316)	7,569	2.11	2.03	16.42
Mar-25	3,746	6,854	2,925	3,930	604	6.5058	749	943	7,798	1.83	2.08	16.66
Apr-25	3,756	4,938	2,925	2,013	359	5.6067	410	286	5,224	1.31	1.39	16.54
May-25	3,707	3,493	2,925	568	160	3.5515	155	(18)	3,475	0.94	0.94	16.19
Jun-25	3,735	3,857	2,925	932	20	4.5791	27	32	3,889	1.03	1.04	16.17
Jul-25	3,718	2,983	2,983	0	0	0.0000	0	0	2,983	0.80	0.80	15.93
Aug-25	3,705	2,943	2,943	0	24	0.0000	8	0	2,943	0.79	0.79	16.20
Sep-25	3,697	2,861	2,861	0	17	0.0000	68	0	2,861	0.77	0.77	16.27

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	14,029	555,339	255,292	300,048	335	894.3723	309	(23,687)	531,653	39.59	37.90	
Nov-12	14,016	1,007,356	255,292	752,064	785	958.5755	647	(131,866)	875,490	71.87	62.46	
Dec-12	14,065	1,340,248	255,292	1,084,956	853	1,271.2722	895	52,832	1,393,080	95.29	99.05	
Jan-13	14,031	1,632,204	255,292	1,376,913	1,047	1,315.1922	1,069	29,028	1,661,232	116.33	118.40	
Feb-13	13,980	1,596,834	255,292	1,341,542	974	1,377.0850	881	(128,330)	1,468,503	114.22	105.04	
Mar-13	13,766	1,318,402	255,292	1,063,110	884	1,203.2583	749	(161,870)	1,156,532	95.77	84.01	
Apr-13	13,533	780,053	255,292	524,761	427	1,229.6560	410	(20,602)	759,450	57.64	56.12	
May-13	13,453	374,026	255,292	118,735	178	665.6411	155	(15,560)	358,466	27.80	26.65	
Jun-13	13,337	227,847	227,847	0	21	0.0000	27	0	227,847	17.08	17.08	
Jul-13	13,275	226,406	226,406	0	4	0.0000	0	0	226,406	17.06	17.06	
Aug-13	13,235	254,250	254,250	0	12	0.0000	8	0	254,250	19.21	19.21	
Sep-13	13,141	291,792	240,328	51,464	143	360.7206	68	(26,935)	264,857	22.20	20.16	663.13
Oct-13	13,096	467,030	240,328	226,703	327	692.5134	309	(12,716)	454,315	35.66	34.69	659.92
Nov-13	13,138	967,949	240,328	727,621	773	941.4501	647	(118,503)	849,446	73.68	64.66	662.12
Dec-13	13,302	1,457,407	240,328	1,217,079	1,012	1,202.8004	895	(140,573)	1,316,834	109.56	99.00	662.06
Jan-14	13,288	1,946,825	240,328	1,706,497	1,310	1,302.5118	1,069	(314,112)	1,632,713	146.51	122.87	666.54
Feb-14	13,303	1,695,729	240,328	1,455,401	1,114	1,306.5219	881	(304,355)	1,391,374	127.47	104.59	666.09
Mar-14	13,233	1,426,751	240,328	1,186,423	976	1,215.1548	749	(276,273)	1,150,479	107.82	86.94	669.01
Apr-14	12,972	684,768	240,328	444,440	467	952.4995	410	(53,915)	630,853	52.79	48.63	661.53
May-14	12,912	372,263	240,328	131,935	152	865.4111	155	2,204	374,467	28.83	29.00	663.88
Jun-14	12,798	244,573	240,328	4,245	14	313.1728	27	4,211	248,784	19.11	19.44	666.24
Jul-14	12,759	228,478	228,478	0	10	0.0000	0	0	228,478	17.91	17.91	667.09
Aug-14	12,760	258,574	258,574	0	13	0.0000	8	0	258,574	20.26	20.26	668.14
Sep-14	12,823	264,628	243,526	21,102	98	214.4501	68	(6,520)	258,109	20.64	20.13	668.12
Oct-14	12,802	424,944	243,526	181,418	303	599.2722	309	3,757	428,701	33.19	33.49	666.91
Nov-14	12,950	961,047	243,526	717,521	759	945.4105	647	(105,841)	855,207	74.21	66.04	668.30
Dec-14	13,162	1,337,572	243,526	1,094,046	909	1,203.2653	895	(17,123)	1,320,448	101.62	100.32	669.62
Jan-15	13,235	1,762,259	243,526	1,518,733	1,231	1,233.8364	1,069	(199,762)	1,562,497	133.15	118.06	664.81
Feb-15	13,313	1,874,337	243,526	1,630,810	1,275	1,278.9979	881	(504,013)	1,370,323	140.79	102.93	663.15
Mar-15	13,374	1,478,697	243,526	1,235,171	960	1,286.6714	749	(271,454)	1,207,243	110.57	90.27	666.48
Apr-15	13,481	647,651	243,526	404,125	403	1,002.4714	410	6,888	654,539	48.04	48.55	666.40
May-15	13,667	335,680	243,526	92,154	83	1,113.0213	155	80,365	416,044	24.56	30.44	667.84
Jun-15	13,830	238,049	238,049	0	32	0.0000	27	0	238,049	17.21	17.21	665.61
Jul-15	13,907	254,206	254,206	0	4	0.0000	0	0	254,206	18.28	18.28	665.98
Aug-15	13,914	259,293	259,293	0	6	0.0000	8	0	259,293	18.64	18.64	664.36
Sep-15	13,911	261,360	256,749	4,611	42	108.6112	68	2,775	264,135	18.79	18.99	663.21
Oct-15	14,044	516,296	256,749	259,547	378	686.8616	309	(47,306)	468,990	36.76	33.39	663.12
Nov-15	14,184	780,326	256,749	523,576	508	1,030.0646	647	142,875	923,201	55.01	65.09	662.17
Dec-15	14,310	948,517	256,749	691,767	625	1,107.2317	895	299,205	1,247,722	66.28	87.19	649.04
Jan-16	14,330	1,703,468	256,749	1,446,718	1,130	1,280.6137	1,069	(77,742)	1,625,725	118.87	113.45	644.43
Feb-16	14,388	1,578,339	256,749	1,321,589	936	1,412.3768	909	(37,739)	1,540,600	109.70	107.08	648.58
Mar-16	14,344	990,030	256,749	733,281	582	1,260.5525	749	210,873	1,200,903	69.02	83.72	642.03
Apr-16	14,187	682,548	256,749	425,799	468	909.7187	410	(52,814)	629,734	48.11	44.39	637.86
May-16	14,203	434,048	256,749	177,299	221	802.6713	155	(52,884)	381,163	30.56	26.84	634.26
Jun-16	14,238	285,111	256,749	28,362	25	856.1950	27	1,888	286,999	20.02	20.16	637.20
Jul-16	14,257	246,096	246,096	0	2	0.0000	0	0	246,096	17.26	17.26	636.19
Aug-16	14,219	255,010	255,010	0	3	0.0000	8	0	255,010	17.93	17.93	635.49
Sep-16	14,197	287,999	287,999	0	53	0.0000	68	0	287,999	20.29	20.29	636.78
Oct-16	14,220	462,258	250,553	211,705	324	653.8938	309	(9,652)	452,606	32.51	31.83	635.22
Nov-16	14,268	818,215	250,553	567,662	589	964.1215	647	56,125	874,339	57.35	61.28	631.41
Dec-16	14,392	1,451,992	250,553	1,201,439	973	1,235.2845	895	(95,860)	1,356,132	100.89	94.23	638.45
Jan-17	14,377	1,657,798	250,553	1,407,246	961	1,464.4508	1,069	158,252	1,816,051	115.31	126.32	651.31
Feb-17	14,345	1,221,791	250,553	971,238	719	1,351.6643	881	219,578	1,441,369	85.17	100.48	644.72
Mar-17	14,353	1,292,707	250,553	1,042,155	879	1,184.9801	749	(154,605)	1,138,103	90.07	79.29	640.29

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-17	14,243	638,710	250,553	388,157	264	1,469.6479	410	214,399	853,108	44.84	59.90	655.80
May-17	14,435	415,647	250,553	165,095	205	804.4224	155	(40,409)	375,238	28.79	26.00	654.96
Jun-17	14,526	299,166	250,553	48,614	33	804.4224	27	(5,047)	294,119	20.60	20.25	655.05
Jul-17	14,725	254,640	254,640	0	2	0.0000	0	0	254,640	17.29	17.29	655.08
Aug-17	14,858	291,050	291,050	0	19	0.0000	8	0	291,050	19.59	19.59	656.73
Sep-17	15,026	170,571	170,571	0	89	0.0000	68	0	170,571	11.35	11.35	647.80
Oct-17	15,183	452,263	272,845	179,419	227	789.0967	309	64,412	516,676	29.79	34.03	650.00
Nov-17	15,247	1,252,072	272,845	979,227	684	1,431.8325	647	(52,832)	1,199,240	82.12	78.65	667.37
Dec-17	15,463	1,577,649	272,845	1,304,804	1,087	1,199.9114	895	(230,883)	1,346,766	102.03	87.10	660.24
Jan-18	15,672	2,010,551	272,845	1,737,706	1,156	1,503.6896	1,069	(130,262)	1,880,289	128.29	119.98	653.90
Feb-18	15,703	1,374,896	272,845	1,102,051	775	1,422.6714	881	151,322	1,526,218	87.56	97.19	650.62
Mar-18	15,825	1,519,857	272,845	1,247,012	905	1,378.4815	749	(214,529)	1,305,327	96.04	82.49	653.81
Apr-18	15,915	1,000,743	272,845	727,898	573	1,270.8191	410	(206,862)	793,881	62.88	49.88	643.79
May-18	16,016	343,691	272,845	70,846	69	1,032.3844	155	89,173	432,864	21.46	27.03	644.83
Jun-18	15,919	340,863	272,845	68,018	29	1,151.6018	27	(2,059)	338,804	21.41	21.28	645.86
Jul-18	15,946	276,058	276,058	0	2	0.0000	0	0	276,058	17.31	17.31	645.88
Aug-18	16,104	280,747	280,747	0	2	0.0000	8	0	280,747	17.43	17.43	643.73
Sep-18	16,173	335,717	278,403	57,315	61	935.8746	68	6,325	342,042	20.76	21.15	653.52
Oct-18	16,298	676,964	278,403	398,561	370	1,077.2780	309	(65,682)	611,281	41.54	37.51	657.00
Nov-18	16,446	1,276,687	278,403	998,284	773	1,292.1195	647	(162,283)	1,114,404	77.63	67.76	646.11
Dec-18	16,644	1,611,170	278,403	1,332,768	886	1,504.2807	895	13,564	1,624,734	96.80	97.62	656.63
Jan-19	16,669	2,111,521	278,403	1,833,118	1,146	1,599.2652	1,069	(123,504)	1,988,017	126.67	119.26	655.91
Feb-19	16,647	1,695,455	278,403	1,417,052	904	1,567.4386	881	(36,139)	1,659,316	101.85	99.68	658.40
Mar-19	16,628	1,531,896	278,403	1,253,493	826	1,518.2802	749	(116,301)	1,415,594	92.13	85.13	661.05
Apr-19	16,627	684,167	278,403	405,765	319	1,270.4618	410	115,125	799,292	41.15	48.07	659.24
May-19	16,539	484,130	278,403	205,728	121	1,703.1368	155	58,258	542,389	29.27	32.79	665.00
Jun-19	16,501	318,632	278,403	40,230	25	1,615.6824	27	3,394	322,026	19.31	19.52	663.24
Jul-19	16,505	302,782	302,782	0	1	0.0000	0	0	302,782	18.34	18.34	664.27
Aug-19	16,490	319,149	319,149	0	2	0.0000	8	0	319,149	19.35	19.35	666.19
Sep-19	16,570	280,386	280,386	0	29	0.0000	68	0	280,386	16.92	16.92	661.96
Oct-19	16,610	544,421	310,966	233,456	266	877.5757	309	37,715	582,137	32.78	35.05	659.50
Nov-19	16,664	1,517,735	310,966	1,206,769	764	1,580.2416	647	(184,353)	1,333,382	91.08	80.02	671.76
Dec-19	16,708	1,369,299	310,966	1,058,334	923	1,146.5613	895	(32,161)	1,337,138	81.95	80.03	654.17
Jan-20	16,792	1,868,141	310,966	1,557,175	916	1,700.6631	1,069	260,834	2,128,975	111.25	126.79	661.69
Feb-20	16,821	1,592,686	310,966	1,281,720	822	1,559.3411	909	135,721	1,728,407	94.68	102.75	664.77
Mar-20	16,943	1,122,304	310,966	811,338	595	1,364.5666	749	210,723	1,333,026	66.24	78.68	658.31
Apr-20	17,024	898,888	310,966	587,923	488	1,204.8180	410	(93,947)	804,941	52.80	47.28	657.52
May-20	17,007	433,040	310,966	122,075	217	562.4942	155	(34,888)	398,152	25.46	23.41	648.14
Jun-20	16,958	302,919	302,919	0	13	0.0000	27	0	302,919	17.86	17.86	646.48
Jul-20	16,911	287,260	287,260	0	0	0.0000	0	0	287,260	16.99	16.99	645.13
Aug-20	16,930	254,132	254,132	0	0	0.0000	8	0	254,132	15.01	15.01	640.78
Sep-20	16,888	347,957	270,696	77,260	88	880.0129	68	(17,420)	330,537	20.60	19.57	643.43
Oct-20	16,859	535,817	270,696	265,121	309	857.9961	309	0	535,817	31.78	31.78	640.17
Nov-20	16,870	1,082,511	270,696	811,814	507	1,601.2112	647	224,170	1,306,680	64.17	77.46	637.61
Dec-20	16,858	1,566,846	270,696	1,296,149	940	1,378.8822	895	(62,050)	1,504,796	92.94	89.26	646.84
Jan-21	16,865	1,981,181	270,696	1,710,485	1,025	1,668.7659	1,069	73,426	2,054,607	117.47	121.83	641.88
Feb-21	16,859	1,874,163	270,696	1,603,466	969	1,654.7642	881	(145,619)	1,728,544	111.17	102.53	641.66
Mar-21	16,781	1,271,146	270,696	1,000,449	649	1,541.5244	749	154,152	1,425,298	75.75	84.94	647.92
Apr-21	16,746	788,645	270,696	517,949	388	1,334.9193	410	29,368	818,013	47.09	48.85	649.48
May-21	16,726	495,878	270,696	225,181	204	1,103.8290	155	(54,088)	441,790	29.65	26.41	652.49
Jun-21	16,771	292,860	270,696	22,164	12	1,219.3741	27	18,291	311,151	17.46	18.55	653.18
Jul-21	16,811	313,066	313,066	0	0	0.0000	0	0	313,066	18.62	18.62	654.81
Aug-21	16,830	331,675	331,675	0	0	0.0000	8	0	331,675	19.71	19.71	659.51
Sep-21	16,856	337,082	302,963	34,119	53	643.7470	68	9,656	346,738	20.00	20.57	660.51

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-21	16,951	502,215	302,963	199,252	183	1,088.8091	309	137,190	639,405	29.63	37.72	666.45
Nov-21	17,091	1,338,356	302,963	1,035,393	720	1,438.0459	647	(104,977)	1,233,379	78.31	72.17	661.16
Dec-21	17,204	1,438,916	302,963	1,135,953	759	1,496.6442	895	203,544	1,642,460	83.64	95.47	667.36
Jan-22	17,259	2,330,544	302,963	2,027,581	1,219	1,663.3151	1,069	(249,497)	2,081,047	135.03	120.58	666.11
Feb-22	17,319	1,744,341	302,963	1,441,378	867	1,662.4894	881	23,275	1,767,616	100.72	102.06	665.65
Mar-22	17,401	1,397,660	302,963	1,094,697	674	1,624.1789	749	121,813	1,519,473	80.32	87.32	668.03
Apr-22	17,479	881,278	302,963	578,314	450	1,285.1431	410	(51,406)	829,872	50.42	47.48	666.66
May-22	17,573	389,281	302,963	86,318	94	918.2745	155	56,015	445,296	22.15	25.34	665.59
Jun-22	17,629	339,737	302,963	36,774	6	1,101.7088	27	23,136	362,873	19.27	20.58	667.62
Jul-22	17,637	292,040	292,040	0	0	0.0000	0	0	292,040	16.56	16.56	665.55
Aug-22	17,638	267,823	267,823	0	0	0.0000	8	0	267,823	15.18	15.18	661.03
Sep-22	17,592	400,970	279,931	121,039	81	1,494.3070	68	(19,426)	381,544	22.79	21.69	662.15
Oct-22	17,582	746,316	279,931	466,384	378	1,233.8207	309	(85,134)	661,182	42.45	37.61	662.03
Nov-22	17,545	1,090,008	279,931	810,077	583	1,389.4973	647	88,928	1,178,936	62.13	67.19	657.06
Dec-22	17,625	1,874,847	279,931	1,594,916	964	1,654.4772	895	(114,159)	1,760,688	106.37	99.90	661.49
Jan-23	17,598	1,591,787	279,931	1,311,855	820	1,599.8236	1,069	398,356	1,990,143	90.45	113.09	654.00
Feb-23	17,572	1,641,517	279,931	1,361,586	748	1,820.3019	881	242,100	1,883,617	93.42	107.19	659.14
Mar-23	17,716	1,441,773	279,931	1,161,841	734	1,582.8901	749	23,743	1,465,516	81.38	82.72	654.54
Apr-23	18,031	687,241	279,931	407,310	311	1,309.6770	410	129,658	816,899	38.11	45.31	652.36
May-23	18,256	546,997	279,931	267,066	164	1,628.4507	155	(14,656)	532,341	29.96	29.16	656.18
Jun-23	18,427	364,740	279,931	84,808	21	1,469.0638	27	8,814	373,554	19.79	20.27	655.87
Jul-23	18,652	322,357	322,357	0	0	0.0000	0	0	322,357	17.28	17.28	656.60
Aug-23	18,840	376,682	376,682	0	1	0.0000	8	0	376,682	19.99	19.99	661.41
Sep-23	18,905	380,933	343,548	37,384	71	526.5389	68	(1,580)	379,353	20.15	20.07	659.78
Oct-23	18,980	681,897	343,548	338,349	289	1,170.7578	309	23,415	705,313	35.93	37.16	659.34
Nov-23	19,142	1,362,871	343,548	1,019,322	678	1,503.4250	647	(46,606)	1,316,264	71.20	68.76	660.91
Dec-23	19,454	1,673,855	343,548	1,330,306	756	1,759.6642	895	244,593	1,918,448	86.04	98.61	659.62
Jan-24	19,526	2,257,514	343,548	1,913,966	985	1,943.1124	1,069	163,221	2,420,736	115.62	123.97	670.51
Feb-24	19,409	1,807,504	343,548	1,463,955	815	1,796.2643	909	168,849	1,976,353	93.13	101.83	665.14
Mar-24	19,319	1,373,662	343,548	1,030,113	603	1,708.3142	749	249,414	1,623,076	71.10	84.01	666.43
Apr-24	19,240	881,383	343,548	537,834	341	1,577.2261	410	108,829	990,211	45.81	51.47	672.60
May-24	19,111	468,978	343,548	125,430	95	1,320.3158	155	79,219	548,197	24.54	28.68	672.12
Jun-24	19,081	409,197	343,548	65,649	4	1,448.7709	27	33,322	442,519	21.45	23.19	675.04
Jul-24	19,063	391,711	391,711	0	0	0.0000	0	0	391,711	20.55	20.55	678.31
Aug-24	18,977	381,062	381,062	0	12	0.0000	8	0	381,062	20.08	20.08	678.39
Sep-24	19,007	308,262	308,262	0	35	0.0000	68	0	308,262	16.22	16.22	674.54
Oct-24	19,012	592,203	344,662	247,542	278	890.4374	309	27,604	619,807	31.15	32.60	669.98
Nov-24	18,953	1,117,617	344,662	772,955	562	1,375.3646	647	116,906	1,234,523	58.97	65.14	666.36
Dec-24	18,957	2,078,493	344,662	1,733,831	957	1,811.7361	895	(112,328)	1,966,166	109.64	103.72	671.46
Jan-25	18,940	2,677,795	344,662	2,333,133	1,216	1,918.6951	1,069	(282,048)	2,395,747	141.38	126.49	673.98
Feb-25	18,885	2,106,363	344,662	1,761,701	941	1,872.1583	881	(112,329)	1,994,033	111.54	105.59	677.74
Mar-25	18,777	1,301,527	344,662	956,865	604	1,584.2131	749	229,711	1,531,238	69.31	81.55	675.27
Apr-25	18,631	937,798	344,662	593,136	359	1,652.1902	410	84,262	1,022,060	50.34	54.86	678.66
May-25	18,682	486,033	344,662	141,371	160	883.5687	155	(4,418)	481,615	26.02	25.78	675.76
Jun-25	18,701	398,244	344,662	53,582	20	1,267.8795	27	8,875	407,119	21.30	21.77	674.34
Jul-25	18,680	358,463	358,463	0	0	0.0000	0	0	358,463	19.19	19.19	672.98
Aug-25	18,632	361,909	361,909	0	24	0.0000	8	0	361,909	19.42	19.42	672.32
Sep-25	18,687	351,031	351,031	0	17	0.0000	68	0	351,031	18.78	18.78	674.89

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-26	1,102	361,477	328.0
Nov-26	1,102	632,313	573.8
Dec-26	1,102	1,004,153	911.2
Jan-27	1,102	1,308,129	1,187.1
Feb-27	1,102	1,163,031	1,055.4
Mar-27	1,102	960,946	872.0
Apr-27	1,102	538,581	488.7
May-27	1,102	313,442	284.4
Jun-27	1,102	210,891	191.4
Jul-27	1,102	176,447	160.1
Aug-27	1,102	178,566	162.0
Sep-27	1,102	221,723	201.2
Total			6,415.3

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	5,028	125,624	90,835	34,789	335	103.6981	309	(2,746)	122,878	24.98	24.44	
Nov-12	5,016	142,209	90,835	51,374	785	65.4815	647	(9,008)	133,201	28.35	26.56	
Dec-12	4,997	175,274	90,835	84,439	853	98.9392	895	4,112	179,386	35.08	35.90	
Jan-13	4,979	172,405	90,835	81,570	1,047	77.9135	1,069	1,720	174,125	34.63	34.97	
Feb-13	4,970	169,996	90,835	79,161	974	81.2586	881	(7,572)	162,424	34.20	32.68	
Mar-13	4,960	173,112	90,835	82,277	884	93.1235	749	(12,528)	160,584	34.90	32.38	
Apr-13	4,949	137,501	90,835	46,666	427	87.1910	410	(1,461)	136,040	27.78	27.49	
May-13	4,936	104,981	90,835	14,146	178	79.3056	155	(1,854)	103,127	21.27	20.89	
Jun-13	4,921	90,544	90,544	0	21	0.0000	27	0	90,544	18.40	18.40	
Jul-13	4,921	89,667	89,667	0	4	0.0000	0	0	89,667	18.22	18.22	
Aug-13	4,904	93,665	93,665	0	12	0.0000	8	0	93,665	19.10	19.10	
Sep-13	4,904	102,720	91,666	11,054	143	77.4813	68	(5,786)	96,935	20.95	19.77	310.79
Oct-13	4,905	119,401	91,666	27,735	327	84.7226	309	(1,556)	117,845	24.34	24.03	310.38
Nov-13	4,916	143,784	91,666	52,118	773	67.4336	647	(8,488)	135,296	29.25	27.52	311.34
Dec-13	4,914	176,792	91,666	85,126	1,012	84.1276	895	(9,832)	166,960	35.98	33.98	309.42
Jan-14	4,904	199,516	91,666	107,850	1,310	82.3182	1,069	(19,852)	179,664	40.68	36.64	311.08
Feb-14	4,900	188,798	91,666	97,132	1,114	87.1959	881	(20,312)	168,486	38.53	34.38	312.79
Mar-14	4,888	189,680	91,666	98,014	976	100.3873	749	(22,824)	166,856	38.81	34.14	314.55
Apr-14	4,886	130,911	91,666	39,245	467	84.1076	410	(4,761)	126,150	26.79	25.82	312.88
May-14	4,859	107,466	91,666	15,800	152	92.2475	155	235	107,701	22.12	22.17	314.15
Jun-14	4,858	93,200	91,666	1,534	14	88.1776	27	1,186	94,386	19.18	19.43	315.18
Jul-14	4,842	90,876	90,876	0	10	0.0000	0	0	90,876	18.77	18.77	315.73
Aug-14	4,831	95,470	95,470	0	13	0.0000	8	0	95,470	19.76	19.76	316.39
Sep-14	4,830	97,680	93,173	4,508	98	45.8101	68	(1,393)	96,288	20.22	19.94	316.56
Oct-14	4,832	117,193	93,173	24,020	303	79.3453	309	497	117,690	24.25	24.36	316.89
Nov-14	4,829	149,588	93,173	56,415	759	74.3327	647	(8,322)	141,266	30.98	29.25	318.62
Dec-14	4,803	180,296	93,173	87,123	909	95.8207	895	(1,364)	178,932	37.54	37.25	321.90
Jan-15	4,801	191,797	93,173	98,624	1,231	80.1236	1,069	(12,972)	178,825	39.95	37.25	322.51
Feb-15	4,799	193,847	93,173	100,674	1,275	78.9558	881	(31,114)	162,733	40.39	33.91	322.04
Mar-15	4,798	198,110	93,173	104,937	960	109.3124	749	(23,062)	175,048	41.29	36.48	324.38
Apr-15	4,791	131,510	93,173	38,338	403	95.1008	410	653	132,164	27.45	27.59	326.15
May-15	4,785	100,831	93,173	7,658	83	92.4941	155	6,678	107,509	21.07	22.47	326.45
Jun-15	4,776	91,956	91,956	0	32	0.0000	27	0	91,956	19.25	19.25	326.28
Jul-15	4,768	93,264	93,264	0	4	0.0000	0	0	93,264	19.56	19.56	327.07
Aug-15	4,768	92,746	92,746	0	6	0.0000	8	0	92,746	19.45	19.45	326.76
Sep-15	4,771	95,852	93,005	2,848	42	67.0802	68	1,714	97,566	20.09	20.45	327.27
Oct-15	4,774	122,076	93,005	29,072	378	76.9353	309	(5,299)	116,778	25.57	24.46	327.38
Nov-15	4,771	139,795	93,005	46,790	508	92.0528	647	12,768	152,563	29.30	31.98	330.10
Dec-15	4,775	140,288	93,005	47,283	625	75.6803	895	20,451	160,739	29.38	33.66	326.51
Jan-16	4,770	176,885	93,005	83,880	1,130	74.2495	1,069	(4,507)	172,377	37.08	36.14	325.40
Feb-16	4,771	187,001	93,005	93,996	936	100.4530	909	(2,684)	184,316	39.20	38.63	330.12
Mar-16	4,763	138,663	93,005	45,658	582	78.4887	749	13,130	151,793	29.11	31.87	325.51
Apr-16	4,762	117,978	93,005	24,973	468	53.3552	410	(3,098)	114,880	24.77	24.12	322.05
May-16	4,760	114,885	93,005	21,880	221	99.0570	155	(6,526)	108,359	24.14	22.76	322.34
Jun-16	4,750	117,085	93,005	24,080	25	76.2061	27	168	117,253	24.65	24.68	327.78
Jul-16	4,755	104,757	93,005	11,752	2	76.2061	0	(144)	104,613	22.03	22.00	330.22
Aug-16	4,746	71,191	71,191	0	3	0.0000	8	0	71,191	15.00	15.00	325.76
Sep-16	4,759	78,998	78,998	0	53	0.0000	68	0	78,998	16.60	16.60	321.91
Oct-16	4,769	107,476	75,094	32,382	324	100.0181	309	(1,476)	106,000	22.54	22.23	319.68
Nov-16	4,752	128,627	75,094	53,533	589	90.9214	647	5,293	133,920	27.07	28.18	315.88
Dec-16	4,747	177,809	75,094	102,715	973	105.6088	895	(8,195)	169,614	37.46	35.73	317.95
Jan-17	4,753	193,453	75,094	118,359	961	123.1704	1,069	13,310	206,763	40.70	43.50	325.32
Feb-17	4,745	154,289	75,094	79,195	719	110.2152	881	17,905	172,194	32.52	36.29	322.97
Mar-17	4,749	145,571	75,094	70,477	879	80.1357	749	(10,455)	135,116	30.65	28.45	319.56

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-17	4,759	146,029	75,094	70,935	264	95.1755	410	13,885	159,913	30.68	33.60	329.03
May-17	4,770	91,694	75,094	16,599	205	80.8805	155	(4,063)	87,631	19.22	18.37	324.64
Jun-17	4,762	95,461	75,094	20,367	33	88.0280	27	(552)	94,909	20.05	19.93	319.89
Jul-17	4,761	85,606	85,606	0	2	0.0000	0	0	85,606	17.98	17.98	315.87
Aug-17	4,759	86,301	86,301	0	19	0.0000	8	0	86,301	18.13	18.13	319.00
Sep-17	4,753	77,568	77,568	0	89	0.0000	68	0	77,568	16.32	16.32	318.72
Oct-17	4,771	111,955	85,954	26,001	227	114.3542	309	9,335	121,289	23.47	25.42	321.92
Nov-17	4,770	169,230	85,954	83,276	684	121.7668	647	(4,493)	164,737	35.48	34.54	328.27
Dec-17	4,776	167,421	85,954	81,467	1,087	74.9178	895	(14,415)	153,005	35.05	32.04	324.58
Jan-18	4,787	232,056	85,954	146,102	1,156	126.4268	1,069	(10,952)	221,104	48.48	46.19	327.26
Feb-18	4,787	172,808	85,954	86,854	775	112.1221	881	11,926	184,733	36.10	38.59	329.56
Mar-18	4,776	172,068	85,954	86,114	905	95.1933	749	(14,815)	157,254	36.03	32.93	334.04
Apr-18	4,773	136,871	85,954	50,917	573	88.8943	410	(14,470)	122,400	28.68	25.64	326.08
May-18	4,775	102,347	85,954	16,393	69	92.0438	155	7,950	110,297	21.43	23.10	330.81
Jun-18	4,756	101,001	85,954	15,048	29	92.0438	27	(165)	100,837	21.24	21.20	332.08
Jul-18	4,742	87,527	87,527	0	2	0.0000	0	0	87,527	18.46	18.46	332.56
Aug-18	4,739	92,099	92,099	0	2	0.0000	8	0	92,099	19.43	19.43	333.86
Sep-18	4,759	102,184	89,813	12,371	61	107.1862	68	724	102,908	21.47	21.62	339.16
Oct-18	4,771	124,350	89,813	34,537	370	93.3508	309	(5,692)	118,659	26.06	24.87	338.61
Nov-18	4,783	184,227	89,813	94,414	773	122.2037	647	(15,348)	168,879	38.52	35.31	339.38
Dec-18	4,793	194,415	89,813	104,602	886	118.0634	895	1,065	195,480	40.56	40.78	348.13
Jan-19	4,790	218,988	89,813	129,175	1,146	112.6957	1,069	(8,703)	210,285	45.72	43.90	345.84
Feb-19	4,774	194,184	89,813	104,371	904	115.4479	881	(2,662)	191,523	40.68	40.12	347.37
Mar-19	4,759	192,090	89,813	102,277	826	123.8815	749	(9,489)	182,600	40.36	38.37	352.81
Apr-19	4,749	120,579	89,813	30,766	319	96.3278	410	8,729	129,308	25.39	27.23	354.40
May-19	4,779	113,153	89,813	23,340	121	110.1047	155	3,766	116,919	23.68	24.47	355.76
Jun-19	4,781	107,559	89,813	17,746	25	103.2162	27	217	107,776	22.50	22.54	357.10
Jul-19	4,775	88,301	88,301	0	1	0.0000	0	0	88,301	18.49	18.49	357.14
Aug-19	4,783	90,059	90,059	0	2	0.0000	8	0	90,059	18.83	18.83	356.53
Sep-19	4,789	94,658	89,180	5,478	29	107.1862	68	4,185	98,844	19.77	20.64	355.55
Oct-19	4,794	119,168	89,180	29,988	266	112.7256	309	4,845	124,012	24.86	25.87	356.55
Nov-19	4,793	143,068	89,180	53,888	764	70.5660	647	(8,232)	134,836	29.85	28.13	349.37
Dec-19	4,796	191,088	89,180	101,908	923	110.4034	895	(3,097)	187,991	39.84	39.20	347.78
Jan-20	4,796	207,501	89,180	118,321	916	129.2235	1,069	19,819	227,320	43.27	47.40	351.28
Feb-20	4,788	206,272	89,180	117,092	822	142.4543	909	12,399	218,671	43.08	45.67	356.83
Mar-20	4,787	173,813	89,180	84,633	595	142.3418	749	21,981	195,794	36.31	40.90	359.36
Apr-20	4,789	105,855	89,180	16,675	488	34.1712	410	(2,665)	103,190	22.10	21.55	353.68
May-20	4,783	83,268	83,268	0	217	0.0000	155	0	83,268	17.41	17.41	346.63
Jun-20	4,784	88,676	88,676	0	13	0.0000	27	0	88,676	18.54	18.54	342.62
Jul-20	4,773	80,070	80,070	0	0	0.0000	0	0	80,070	16.78	16.78	340.90
Aug-20	4,767	81,405	81,405	0	0	0.0000	8	0	81,405	17.08	17.08	339.15
Sep-20	4,759	66,348	66,348	0	88	0.0000	68	0	66,348	13.94	13.94	332.45
Oct-20	4,766	118,307	80,737	37,569	309	121.5835	309	0	118,307	24.82	24.82	331.41
Nov-20	4,763	145,591	80,737	64,854	507	127.9169	647	17,908	163,500	30.57	34.33	337.60
Dec-20	4,748	154,249	80,737	73,512	940	78.2038	895	(3,519)	150,730	32.49	31.75	330.15
Jan-21	4,752	191,977	80,737	111,239	1,025	108.5263	1,069	4,775	196,752	40.40	41.40	324.16
Feb-21	4,750	177,209	80,737	96,472	969	99.5581	881	(8,761)	168,448	37.31	35.46	313.95
Mar-21	4,742	158,886	80,737	78,149	649	120.4147	749	12,041	170,928	33.51	36.05	309.09
Apr-21	4,744	118,690	80,737	37,953	388	97.8161	410	2,152	120,842	25.02	25.47	313.02
May-21	4,741	92,611	80,737	11,874	204	58.2055	155	(2,852)	89,759	19.53	18.93	314.54
Jun-21	4,733	71,464	71,464	0	12	0.0000	27	0	71,464	15.10	15.10	311.11
Jul-21	4,722	84,133	84,133	0	0	0.0000	0	0	84,133	17.82	17.82	312.15
Aug-21	4,719	94,589	94,589	0	0	0.0000	8	0	94,589	20.04	20.04	315.12
Sep-21	4,716	91,910	89,361	2,549	53	48.1012	68	722	92,632	19.49	19.64	320.82

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-21	4,720	120,853	89,361	31,492	183	172.0897	309	21,683	142,537	25.60	30.20	326.19
Nov-21	4,721	165,062	89,361	75,701	720	105.1402	647	(7,675)	157,387	34.96	33.34	325.20
Dec-21	4,737	176,536	89,361	87,175	759	114.8552	895	15,620	192,156	37.27	40.56	334.02
Jan-22	4,733	218,373	89,361	129,012	1,219	105.8341	1,069	(15,875)	202,497	46.14	42.78	335.40
Feb-22	4,733	207,527	89,361	118,166	867	136.2935	881	1,908	209,435	43.85	44.25	344.19
Mar-22	4,728	174,902	89,361	85,541	674	126.9156	749	9,519	184,421	36.99	39.01	347.15
Apr-22	4,736	148,281	89,361	58,920	450	130.9334	410	(5,237)	143,044	31.31	30.20	351.88
May-22	4,725	92,938	89,361	3,577	94	38.0577	155	2,322	95,260	19.67	20.16	353.11
Jun-22	4,707	98,852	89,361	9,491	6	38.0577	27	799	99,651	21.00	21.17	359.18
Jul-22	4,699	96,445	96,445	0	0	0.0000	0	0	96,445	20.52	20.52	361.89
Aug-22	4,688	102,633	102,633	0	0	0.0000	8	0	102,633	21.89	21.89	363.74
Sep-22	4,683	126,400	97,648	28,752	81	132.3913	68	(1,721)	124,679	26.99	26.62	370.72
Oct-22	4,686	134,675	97,648	37,026	378	97.9535	309	(6,759)	127,916	28.74	27.30	367.82
Nov-22	4,681	194,910	97,648	97,261	583	166.8291	647	10,677	205,587	41.64	43.92	378.40
Dec-22	4,687	198,191	97,648	100,543	964	104.2979	895	(7,197)	190,995	42.29	40.75	378.58
Jan-23	4,679	207,598	97,648	109,949	820	134.0847	1,069	33,387	240,985	44.37	51.50	387.30
Feb-23	4,683	188,867	97,648	91,218	748	121.9499	881	16,219	205,086	40.33	43.79	386.85
Mar-23	4,678	180,720	97,648	83,072	734	113.1773	749	1,698	182,418	38.63	38.99	386.83
Apr-23	4,674	124,858	97,648	27,210	311	87.4921	410	8,662	133,520	26.71	28.57	385.20
May-23	4,661	106,281	97,648	8,633	164	52.6397	155	(474)	105,807	22.80	22.70	387.74
Jun-23	4,658	105,703	97,648	8,055	21	52.6397	27	316	106,019	22.69	22.76	389.33
Jul-23	4,655	83,580	83,580	0	0	0.0000	0	0	83,580	17.95	17.95	386.76
Aug-23	4,651	106,503	106,503	0	1	0.0000	8	0	106,503	22.90	22.90	387.76
Sep-23	4,651	82,989	82,989	0	71	0.0000	68	0	82,989	17.84	17.84	378.98
Oct-23	4,652	129,514	83,284	46,229	289	159.9625	309	3,199	132,713	27.84	28.53	380.21
Nov-23	4,647	175,023	83,284	91,739	678	135.3076	647	(4,195)	170,828	37.66	36.76	373.06
Dec-23	4,652	180,802	83,284	97,517	756	128.9909	895	17,930	198,731	38.87	42.72	375.03
Jan-24	4,660	228,306	83,284	145,022	985	147.2305	1,069	12,367	240,674	48.99	51.65	375.17
Feb-24	4,665	190,034	83,284	106,750	815	130.9814	909	12,312	202,346	40.74	43.38	374.75
Mar-24	4,653	168,385	83,284	85,101	603	141.1287	749	20,605	188,990	36.19	40.62	376.37
Apr-24	4,640	171,352	83,284	88,067	341	136.0551	410	9,388	180,740	36.93	38.95	386.76
May-24	4,636	135,392	83,284	52,107	95	138.5919	155	8,316	143,707	29.20	31.00	395.06
Jun-24	4,626	110,878	83,284	27,594	4	137.3235	27	3,158	114,036	23.97	24.65	396.95
Jul-24	4,619	104,360	104,360	0	0	0.0000	0	0	104,360	22.59	22.59	401.59
Aug-24	4,625	94,616	94,616	0	12	0.0000	8	0	94,616	20.46	20.46	399.14
Sep-24	4,619	87,190	87,190	0	35	0.0000	68	0	87,190	18.88	18.88	400.18
Oct-24	4,644	99,884	90,903	8,981	278	32.3059	309	1,001	100,886	21.51	21.72	393.37
Nov-24	4,652	147,954	90,903	57,051	562	101.5144	647	8,629	156,583	31.80	33.66	390.27
Dec-24	4,659	194,718	90,903	103,815	957	108.4791	895	(6,726)	187,992	41.79	40.35	387.90
Jan-25	4,665	238,610	90,903	147,707	1216	121.4696	1,069	(17,856)	220,754	51.15	47.32	383.58
Feb-25	4,651	206,837	90,903	115,933	941	123.2021	881	(7,392)	199,444	44.47	42.88	383.08
Mar-25	4,647	171,710	90,903	80,806	604	133.7850	749	19,399	191,108	36.95	41.13	383.59
Apr-25	4,638	143,914	90,903	53,010	359	147.6614	410	7,531	151,445	31.03	32.65	377.29
May-25	4,631	94,622	90,903	3,719	160	23.2440	155	(116)	94,506	20.43	20.41	366.70
Jun-25	4,629	111,573	90,903	20,670	20	85.4527	27	598	112,172	24.10	24.23	366.28
Jul-25	4,616	86,031	86,031	0	0	0.0000	0	0	86,031	18.64	18.64	362.33
Aug-25	4,602	88,869	88,869	0	24	0.0000	8	0	88,869	19.31	19.31	361.18
Sep-25	4,603	95,248	87,450	7,798	17	54.3484	68	2,772	98,020	20.69	21.29	363.60

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
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Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	1,233	51,212	36,787	14,425	335	42.9985	309	(1,139)	50,073	41.53	40.61	
Nov-12	1,235	60,725	36,787	23,938	785	30.5112	647	(4,197)	56,527	49.17	45.77	
Dec-12	1,255	70,122	36,787	33,336	853	39.0604	895	1,623	71,746	55.87	57.17	
Jan-13	1,241	67,680	36,787	30,893	1,047	29.5081	1,069	651	68,331	54.54	55.06	
Feb-13	1,238	70,601	36,787	33,814	974	34.7098	881	(3,235)	67,366	57.03	54.42	
Mar-13	1,225	68,421	36,787	31,634	884	35.8043	749	(4,817)	63,604	55.85	51.92	
Apr-13	1,210	59,892	36,787	23,105	427	54.1411	410	(907)	58,984	49.50	48.75	
May-13	1,206	42,895	36,787	6,108	178	34.2422	155	(800)	42,094	35.57	34.90	
Jun-13	1,198	37,181	36,787	394	21	18.7913	27	113	37,294	31.04	31.13	
Jul-13	1,190	35,626	35,626	0	4	0.0000	0	0	35,626	29.94	29.94	
Aug-13	1,185	37,822	37,822	0	12	0.0000	8	0	37,822	31.92	31.92	
Sep-13	1,186	40,441	36,724	3,717	143	26.0565	68	(1,946)	38,496	34.10	32.46	514.04
Oct-13	1,190	48,920	36,724	12,196	327	37.2545	309	(684)	48,235	41.11	40.53	513.97
Nov-13	1,193	60,609	36,724	23,885	773	30.9038	647	(3,890)	56,719	50.80	47.54	515.74
Dec-13	1,216	70,999	36,724	34,275	1,012	33.8733	895	(3,959)	67,040	58.39	55.13	513.70
Jan-14	1,194	74,801	36,724	38,077	1,310	29.0631	1,069	(7,009)	67,792	62.65	56.78	515.42
Feb-14	1,194	75,635	36,724	38,911	1,114	34.9308	881	(8,137)	67,498	63.35	56.53	517.53
Mar-14	1,184	73,876	36,724	37,152	976	38.0518	749	(8,651)	65,225	62.40	55.09	520.70
Apr-14	1,162	52,991	36,724	16,267	467	34.8631	410	(1,973)	51,018	45.60	43.91	515.86
May-14	1,156	44,902	36,724	8,178	152	36.4575	155	93	44,995	38.84	38.92	519.88
Jun-14	1,159	36,574	36,574	0	14	0.0000	27	0	36,574	31.56	31.56	520.30
Jul-14	1,165	35,435	35,435	0	10	0.0000	0	0	35,435	30.42	30.42	520.78
Aug-14	1,166	38,234	38,234	0	13	0.0000	8	0	38,234	32.79	32.79	521.66
Sep-14	1,167	37,897	36,834	1,062	98	10.7965	68	(328)	37,569	32.47	32.19	521.39
Oct-14	1,159	48,477	36,834	11,642	303	38.4572	309	241	48,718	41.83	42.03	522.89
Nov-14	1,185	65,349	36,834	28,515	759	37.5717	647	(4,206)	61,143	55.15	51.60	526.94
Dec-14	1,202	70,872	36,834	34,037	909	37.4354	895	(533)	70,339	58.96	58.52	530.33
Jan-15	1,197	74,413	36,834	37,578	1,231	30.5291	1,069	(4,943)	69,470	62.17	58.04	531.59
Feb-15	1,195	77,627	36,834	40,793	1,275	31.9926	881	(12,607)	65,020	64.96	54.41	529.47
Mar-15	1,194	83,165	36,834	46,331	960	48.2629	749	(10,182)	72,983	69.65	61.13	535.51
Apr-15	1,204	56,249	36,834	19,415	403	48.1605	410	331	56,580	46.72	46.99	538.59
May-15	1,219	42,800	36,834	5,966	83	48.2117	155	3,481	46,281	35.11	37.97	537.64
Jun-15	1,228	38,418	36,834	1,584	32	48.8594	27	(265)	38,154	31.29	31.07	537.15
Jul-15	1,229	39,789	39,789	0	4	0.0000	0	0	39,789	32.38	32.38	539.11
Aug-15	1,237	39,697	39,697	0	6	0.0000	8	0	39,697	32.09	32.09	538.41
Sep-15	1,234	39,943	39,743	200	42	4.7066	68	120	40,063	32.37	32.47	538.68
Oct-15	1,255	55,563	39,743	15,820	378	41.8646	309	(2,883)	52,679	44.27	41.98	538.63
Nov-15	1,262	62,109	39,743	22,366	508	44.0017	647	6,103	68,212	49.21	54.05	541.08
Dec-15	1,258	61,707	39,743	21,963	625	35.1542	895	9,500	71,206	49.05	56.60	539.16
Jan-16	1,256	70,579	39,743	30,835	1,130	27.2950	1,069	(1,657)	68,922	56.19	54.87	536.00
Feb-16	1,259	78,454	39,743	38,711	936	41.3704	909	(1,105)	77,349	62.31	61.44	543.03
Mar-16	1,255	61,323	39,743	21,580	582	37.0974	749	6,206	67,529	48.86	53.81	535.71
Apr-16	1,246	51,989	39,743	12,246	468	26.1635	410	(1,519)	50,470	41.72	40.51	529.22
May-16	1,247	48,700	39,743	8,957	221	40.5515	155	(2,672)	46,029	39.05	36.91	528.17
Jun-16	1,245	39,598	39,598	0	25	0.0000	27	0	39,598	31.81	31.81	528.90
Jul-16	1,240	38,088	38,088	0	2	0.0000	0	0	38,088	30.72	30.72	527.24
Aug-16	1,250	37,894	37,894	0	3	0.0000	8	0	37,894	30.32	30.32	525.47
Sep-16	1,249	40,329	40,329	0	53	0.0000	68	0	40,329	32.29	32.29	525.29
Oct-16	1,255	48,978	37,991	10,987	324	33.9344	309	(501)	48,477	39.03	38.63	521.94
Nov-16	1,247	57,277	37,991	19,286	589	32.7560	647	1,907	59,184	45.93	47.46	515.35
Dec-16	1,260	71,745	37,991	33,754	973	34.7050	895	(2,693)	69,052	56.94	54.80	513.55
Jan-17	1,253	82,460	37,991	44,469	961	46.2767	1,069	5,001	87,461	65.81	69.80	528.48
Feb-17	1,254	66,372	37,991	28,380	719	39.4968	881	6,416	72,788	52.93	58.04	525.09
Mar-17	1,254	65,110	37,991	27,119	879	30.8352	749	(4,023)	61,087	51.92	48.71	519.99

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Apr-17	1,250	55,001	37,991	17,010	264	35.1660	410	5,130	60,131	44.00	48.11	527.59
May-17	1,268	43,410	37,991	5,419	205	26.4033	155	(1,326)	42,084	34.23	33.19	523.87
Jun-17	1,281	38,552	37,991	561	33	16.8656	27	(106)	38,446	30.10	30.01	522.08
Jul-17	1,293	36,292	36,292	0	2	0.0000	0	0	36,292	28.07	28.07	519.43
Aug-17	1,308	39,317	39,317	0	19	0.0000	8	0	39,317	30.06	30.06	519.17
Sep-17	1,325	40,723	37,805	2,919	89	32.6507	68	(698)	40,025	30.73	30.21	517.09
Oct-17	1,343	32,791	32,791	0	227	0.0000	309	0	32,791	24.42	24.42	502.88
Nov-17	1,353	79,222	37,805	41,417	684	60.5600	647	(2,235)	76,987	58.55	56.90	512.32
Dec-17	1,381	72,035	37,805	34,230	1,087	31.4786	895	(6,057)	65,978	52.16	47.78	505.29
Jan-18	1,391	109,373	37,805	71,568	1,156	61.9302	1,069	(5,365)	104,008	78.63	74.77	510.26
Feb-18	1,401	75,487	37,805	37,682	775	48.6452	881	5,174	80,661	53.88	57.57	509.79
Mar-18	1,408	70,652	37,805	32,848	905	36.3108	749	(5,651)	65,001	50.18	46.17	507.25
Apr-18	1,419	61,634	37,805	23,830	573	41.6036	410	(6,772)	54,862	43.44	38.66	497.80
May-18	1,417	44,166	37,805	6,362	69	38.9572	155	3,365	47,531	31.17	33.54	498.16
Jun-18	1,407	42,003	37,805	4,199	29	38.9572	27	(70)	41,934	29.85	29.80	497.95
Jul-18	1,404	37,331	37,331	0	2	0.0000	0	0	37,331	26.59	26.59	496.47
Aug-18	1,401	36,187	36,187	0	2	0.0000	8	0	36,187	25.83	25.83	492.24
Sep-18	1,417	40,600	36,759	3,841	61	32.6507	68	221	40,821	28.65	28.81	490.84
Oct-18	1,422	43,279	36,759	6,520	370	17.6220	309	(1,074)	42,205	30.44	29.68	496.10
Nov-18	1,418	91,635	36,759	54,876	773	71.0277	647	(8,921)	82,714	64.62	58.33	497.54
Dec-18	1,433	85,416	36,759	48,657	886	54.9184	895	495	85,911	59.61	59.95	509.71
Jan-19	1,427	89,932	36,759	53,172	1,146	46.3891	1,069	(3,582)	86,349	63.02	60.51	495.45
Feb-19	1,422	76,859	36,759	40,100	904	44.3555	881	(1,023)	75,837	54.05	53.33	491.21
Mar-19	1,405	79,213	36,759	42,453	826	51.4211	749	(3,939)	75,274	56.38	53.58	498.62
Apr-19	1,399	51,929	36,759	15,170	319	47.4979	410	4,304	56,233	37.12	40.20	500.15
May-19	1,424	52,875	36,759	16,116	121	49.4595	155	1,692	54,567	37.13	38.32	504.93
Jun-19	1,421	41,721	36,759	4,961	25	48.4787	27	102	41,822	29.36	29.43	504.55
Jul-19	1,405	39,773	39,773	0	1	0.0000	0	0	39,773	28.31	28.31	506.27
Aug-19	1,411	40,109	40,109	0	2	0.0000	8	0	40,109	28.43	28.43	508.87
Sep-19	1,421	39,038	39,038	0	29	0.0000	68	0	39,038	27.47	27.47	507.53
Oct-19	1,421	51,286	39,406	11,881	266	44.6602	309	1,919	53,206	36.09	37.44	515.30
Nov-19	1,420	63,352	39,406	23,946	764	31.3574	647	(3,658)	59,694	44.61	42.04	499.00
Dec-19	1,420	75,615	39,406	36,209	923	39.2273	895	(1,100)	74,514	53.25	52.47	491.53
Jan-20	1,421	80,725	39,406	41,319	916	45.1264	1,069	6,921	87,646	56.81	61.68	492.69
Feb-20	1,419	75,951	39,406	36,546	822	44.4614	909	3,870	79,821	53.52	56.25	495.62
Mar-20	1,419	78,650	39,406	39,245	595	66.0045	749	10,193	88,843	55.43	62.61	504.65
Apr-20	1,424	50,274	39,406	10,868	488	22.2721	410	(1,737)	48,537	35.30	34.09	498.54
May-20	1,416	33,078	33,078	0	217	0.0000	155	0	33,078	23.36	23.36	483.58
Jun-20	1,410	37,014	37,014	0	13	0.0000	27	0	37,014	26.25	26.25	480.40
Jul-20	1,422	32,973	32,973	0	0	0.0000	0	0	32,973	23.19	23.19	475.28
Aug-20	1,424	33,755	33,755	0	0	0.0000	8	0	33,755	23.70	23.70	470.56
Sep-20	1,425	37,000	33,364	3,636	88	41.4100	68	(820)	36,180	25.96	25.39	468.47
Oct-20	1,428	52,897	33,364	19,533	309	63.2131	309	0	52,897	37.04	37.04	468.07
Nov-20	1,430	63,867	33,364	30,503	507	60.1636	647	8,423	72,290	44.66	50.55	476.59
Dec-20	1,419	64,977	33,364	31,613	940	33.6307	895	(1,513)	63,464	45.79	44.72	468.84
Jan-21	1,425	89,784	33,364	56,420	1,025	55.0440	1,069	2,422	92,206	63.01	64.71	471.87
Feb-21	1,422	82,923	33,364	49,559	969	51.1445	881	(4,501)	78,422	58.31	55.15	470.76
Mar-21	1,417	68,642	33,364	35,278	649	54.3579	749	5,436	74,078	48.44	52.28	460.43
Apr-21	1,415	52,808	33,364	19,444	388	50.1133	410	1,102	53,911	37.32	38.10	464.45
May-21	1,411	41,445	33,364	8,080	204	39.6097	155	(1,941)	39,504	29.37	28.00	469.08
Jun-21	1,408	31,174	31,174	0	12	0.0000	27	0	31,174	22.14	22.14	464.97
Jul-21	1,407	37,571	37,571	0	0	0.0000	0	0	37,571	26.70	26.70	468.49
Aug-21	1,393	42,007	42,007	0	0	0.0000	8	0	42,007	30.16	30.16	474.94
Sep-21	1,393	41,562	34,372	7,190	53	44.8615	68	673	42,235	29.84	30.32	479.87

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Oct-21	1,403	56,616	34,372	22,244	183	55.7770	309	7,028	63,644	40.35	45.36	488.19
Nov-21	1,405	73,838	34,372	39,466	720	54.8139	647	(4,001)	69,837	52.55	49.71	487.34
Dec-21	1,403	77,438	34,372	43,066	759	56.7402	895	7,717	85,155	55.19	60.69	503.31
Jan-22	1,390	92,730	34,372	58,358	1,219	47.8735	1,069	(7,181)	85,549	66.71	61.55	500.15
Feb-22	1,385	82,123	34,372	47,751	867	55.0762	881	771	82,894	59.29	59.85	504.85
Mar-22	1,400	69,499	34,372	35,127	674	52.1172	749	3,909	73,408	49.64	52.43	505.01
Apr-22	1,402	55,336	34,372	20,964	450	46.5871	410	(1,863)	53,473	39.47	38.14	505.05
May-22	1,410	36,274	34,372	1,902	94	20.2324	155	1,234	37,508	25.73	26.60	503.66
Jun-22	1,409	36,252	34,372	1,879	6	33.4098	27	702	36,953	25.73	26.23	507.74
Jul-22	1,413	34,015	34,015	0	0	0.0000	0	0	34,015	24.07	24.07	505.11
Aug-22	1,409	34,693	34,693	0	0	0.0000	8	0	34,693	24.62	24.62	499.58
Sep-22	1,411	49,267	34,354	14,913	81	59.9379	68	(779)	48,488	34.92	34.36	503.62
Oct-22	1,411	57,530	34,354	23,176	378	61.3132	309	(4,231)	53,300	40.77	37.77	496.03
Nov-22	1,423	68,496	34,354	34,142	583	58.5626	647	3,748	72,244	48.13	50.77	497.10
Dec-22	1,428	78,387	34,354	44,033	964	45.6769	895	(3,152)	75,235	54.89	52.69	489.09
Jan-23	1,428	76,944	34,354	42,590	820	51.9391	1,069	12,933	89,877	53.88	62.94	490.48
Feb-23	1,415	76,688	34,354	42,334	748	56.5966	881	7,527	84,216	54.20	59.52	490.15
Mar-23	1,424	67,468	34,354	33,114	734	45.1143	749	677	68,145	47.38	47.85	485.57
Apr-23	1,426	53,279	34,354	18,925	311	60.8530	410	6,024	59,304	37.36	41.59	489.01
May-23	1,460	47,683	34,354	13,329	164	81.2751	155	(731)	46,952	32.66	32.16	494.57
Jun-23	1,464	41,563	34,354	7,209	21	71.0640	27	426	41,989	28.39	28.68	497.02
Jul-23	1,498	36,079	36,079	0	0	0.0000	0	0	36,079	24.08	24.08	497.04
Aug-23	1,506	53,895	53,895	0	1	0.0000	8	0	53,895	35.79	35.79	508.20
Sep-23	1,515	36,286	36,286	0	71	0.0000	68	0	36,286	23.95	23.95	497.79
Oct-23	1,524	62,073	38,821	23,252	289	80.4560	309	1,609	63,682	40.73	41.79	501.80
Nov-23	1,532	91,925	38,821	53,104	678	78.3242	647	(2,428)	89,497	60.00	58.42	509.45
Dec-23	1,559	81,358	38,821	42,537	756	56.2662	895	7,821	89,179	52.19	57.20	513.97
Jan-24	1,559	119,172	38,821	80,352	985	81.5752	1,069	6,852	126,025	76.44	80.84	531.86
Feb-24	1,561	94,722	38,821	55,901	815	68.5905	909	6,448	101,170	60.68	64.81	537.16
Mar-24	1,544	82,856	38,821	44,036	603	73.0275	749	10,662	93,518	53.66	60.57	549.87
Apr-24	1,545	101,931	38,821	63,110	341	70.8090	410	4,886	106,817	65.97	69.14	577.42
May-24	1,537	74,968	38,821	36,147	95	71.9182	155	4,315	79,283	48.78	51.58	596.85
Jun-24	1,535	57,206	38,821	18,385	4	71.3636	27	1,641	58,847	37.27	38.34	606.50
Jul-24	1,535	47,377	47,377	0	0	0.0000	0	0	47,377	30.86	30.86	613.28
Aug-24	1,527	44,129	44,129	0	12	0.0000	8	0	44,129	28.90	28.90	606.40
Sep-24	1,522	36,870	36,870	0	35	0.0000	68	0	36,870	24.23	24.23	606.67
Oct-24	1,526	42,265	40,500	1,765	278	6.3496	309	197	42,462	27.70	27.83	592.71
Nov-24	1,500	68,102	40,500	27,602	562	49.1133	647	4,175	72,276	45.40	48.18	582.47
Dec-24	1,503	78,880	40,500	38,380	957	40.1045	895	(2,486)	76,393	52.48	50.83	576.10
Jan-25	1,498	101,086	40,500	60,586	1,216	49.8239	1,069	(7,324)	93,762	67.48	62.59	557.85
Feb-25	1,492	88,149	40,500	47,649	941	50.6369	881	(3,038)	85,111	59.08	57.04	550.09
Mar-25	1,486	71,286	40,500	30,787	604	50.9712	749	7,391	78,677	47.97	52.95	542.46
Apr-25	1,480	63,514	40,500	23,014	359	64.1069	410	3,269	66,784	42.92	45.12	518.45
May-25	1,497	39,926	39,926	0	160	0.0000	155	0	39,926	26.67	26.67	493.54
Jun-25	1,492	48,494	40,500	7,994	20	57.5390	27	403	48,897	32.50	32.77	487.98
Jul-25	1,490	37,698	37,698	0	0	0.0000	0	0	37,698	25.30	25.30	482.41
Aug-25	1,484	40,225	40,225	0	24	0.0000	8	0	40,225	27.11	27.11	480.62
Sep-25	1,486	39,998	38,962	1,036	17	60.9630	68	3,109	43,107	26.92	29.01	485.40

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating-Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-26	23	16,090	699.6
Nov-26	23	19,013	826.7
Dec-26	23	24,319	1,057.3
Jan-27	23	26,966	1,172.4
Feb-27	23	24,047	1,045.5
Mar-27	23	20,258	880.8
Apr-27	23	15,994	695.4
May-27	23	13,147	571.6
Jun-27	23	11,903	517.5
Jul-27	23	11,991	521.3
Aug-27	23	14,196	617.2
Sep-27	23	14,245	619.3
Total			9,224.8

UGI Utilities, Inc. - Gas Division
Industrial - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	1,467	259,165	148,424	110,741	335	330.0946	309	(8,742)	250,423	176.66	170.70	
Nov-12	1,476	391,756	148,424	243,332	785	310.1494	647	(42,665)	349,091	265.42	236.51	
Dec-12	1,480	520,902	148,424	372,478	853	436.4428	895	18,138	539,040	351.96	364.22	
Jan-13	1,479	642,939	148,424	494,515	1,047	472.3484	1,069	10,425	653,364	434.71	441.76	
Feb-13	1,481	634,585	148,424	486,161	974	499.0415	881	(46,506)	588,079	428.48	397.08	
Mar-13	1,480	529,677	148,424	381,253	884	431.5128	749	(58,050)	471,627	357.89	318.67	
Apr-13	1,476	326,304	148,424	177,880	427	416.8202	410	(6,984)	319,320	221.07	216.34	
May-13	1,470	167,138	148,424	18,715	178	104.9164	155	(2,453)	164,686	113.70	112.03	
Jun-13	1,459	135,191	135,191	0	21	0.0000	27	0	135,191	92.66	92.66	
Jul-13	1,457	142,941	142,941	0	4	0.0000	0	0	142,941	98.11	98.11	
Aug-13	1,457	150,155	139,066	11,089	12	216.4754	8	(932)	149,223	103.06	102.42	
Sep-13	1,450	153,623	139,066	14,557	143	102.0312	68	(7,619)	146,004	105.95	100.69	2651.19
Oct-13	1,452	247,396	139,066	108,330	327	330.9196	309	(6,076)	241,320	170.38	166.20	2646.69
Nov-13	1,461	419,619	139,066	280,553	773	363.0001	647	(45,692)	373,927	287.21	255.94	2666.11
Dec-13	1,464	620,749	139,066	481,683	1,012	476.0323	895	(55,634)	565,115	424.01	386.01	2687.91
Jan-14	1,464	840,571	139,066	701,505	1,310	535.4348	1,069	(129,125)	711,446	574.16	485.96	2732.10
Feb-14	1,462	733,326	139,066	594,260	1,114	533.4708	881	(124,272)	609,054	501.59	416.59	2751.61
Mar-14	1,455	664,866	139,066	525,800	976	538.5335	749	(122,439)	542,428	456.95	372.80	2805.75
Apr-14	1,451	326,399	139,066	187,333	467	401.4812	410	(22,726)	303,673	224.95	209.29	2798.69
May-14	1,444	217,428	139,066	78,362	152	514.0094	155	1,309	218,737	150.57	151.48	2838.14
Jun-14	1,434	143,487	143,487	0	14	0.0000	27	0	143,487	100.06	100.06	2845.54
Jul-14	1,433	153,963	153,963	0	10	0.0000	0	0	153,963	107.44	107.44	2854.88
Aug-14	1,431	154,445	148,725	5,719	13	435.5129	8	(2,235)	152,209	107.93	106.37	2858.82
Sep-14	1,432	172,167	148,725	23,442	98	238.2260	68	(7,242)	164,925	120.23	115.17	2873.30
Oct-14	1,435	236,773	148,725	88,048	303	290.8450	309	1,823	238,596	165.00	166.27	2873.37
Nov-14	1,447	425,403	148,725	276,678	759	364.5523	647	(40,812)	384,591	293.99	265.78	2883.22
Dec-14	1,450	641,288	148,725	492,563	909	541.7358	895	(7,709)	633,579	442.27	436.95	2934.16
Jan-15	1,448	758,233	148,725	609,508	1,231	495.1711	1,069	(80,170)	678,063	523.64	468.28	2916.48
Feb-15	1,447	901,400	148,725	752,674	1,275	590.3009	881	(232,619)	668,780	622.94	462.18	2962.07
Mar-15	1,442	649,620	148,725	500,894	960	521.7791	749	(110,082)	539,538	450.50	374.16	2963.43
Apr-15	1,435	299,735	148,725	151,010	403	374.5951	410	2,574	302,309	208.87	210.67	2964.81
May-15	1,427	180,682	148,725	31,957	83	385.9682	155	27,868	208,550	126.62	146.15	2959.48
Jun-15	1,423	116,549	116,549	0	32	0.0000	27	0	116,549	81.90	81.90	2941.32
Jul-15	1,422	196,406	133,412	62,995	4	380.2817	0	(1,576)	194,830	138.12	137.01	2970.89
Aug-15	1,420	150,275	150,275	0	6	0.0000	8	0	150,275	105.83	105.83	2970.35
Sep-15	1,421	166,763	133,412	33,351	42	381.3114	68	9,742	176,505	117.36	124.21	2979.39
Oct-15	1,419	259,516	133,412	126,105	378	333.7217	309	(22,985)	236,532	182.89	166.69	2979.81
Nov-15	1,421	351,420	133,412	218,008	508	428.9011	647	59,491	410,911	247.30	289.17	3003.20
Dec-15	1,421	425,797	133,412	292,386	625	467.9879	895	126,463	552,261	299.65	388.64	2954.89
Jan-16	1,422	663,186	133,412	529,774	1,130	468.9480	1,069	(28,469)	634,717	466.38	446.36	2932.97
Feb-16	1,419	663,664	133,412	530,253	936	566.6786	909	(15,142)	648,523	467.70	457.03	2927.81
Mar-16	1,415	423,984	133,412	290,573	582	499.5113	749	83,561	507,546	299.64	358.69	2912.34
Apr-16	1,416	295,822	133,412	162,410	468	346.9890	410	(20,145)	275,677	208.91	194.69	2896.36
May-16	1,415	194,867	133,412	61,455	221	278.2232	155	(18,331)	176,536	137.72	124.76	2874.98
Jun-16	1,412	105,184	105,184	0	25	0.0000	27	0	105,184	74.49	74.49	2867.57
Jul-16	1,414	180,566	132,180	48,385	2	312.6061	0	(592)	179,973	127.70	127.28	2857.83
Aug-16	1,413	159,177	159,177	0	3	0.0000	8	0	159,177	112.65	112.65	2864.66
Sep-16	1,412	190,675	132,180	58,495	53	396.4813	68	6,131	196,806	135.04	139.38	2879.83
Oct-16	1,417	245,047	132,180	112,867	324	348.6128	309	(5,146)	239,902	172.93	169.30	2882.44
Nov-16	1,418	393,808	132,180	261,627	589	444.3499	647	25,867	419,675	277.72	295.96	2889.23
Dec-16	1,415	600,831	132,180	468,651	973	481.8531	895	(37,392)	563,439	424.62	398.19	2898.78
Jan-17	1,417	676,881	132,180	544,701	961	566.8430	1,069	61,254	738,135	477.69	520.91	2973.34
Feb-17	1,411	527,698	132,180	395,518	719	550.4390	881	89,419	617,117	373.99	437.36	2953.67
Mar-17	1,412	570,494	132,180	438,314	879	498.3837	749	(65,024)	505,470	404.03	357.98	2952.96

UGI Utilities, Inc. - Gas Division
Industrial - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Apr-17	1,406	295,782	132,180	163,601	264	619.4301	410	90,365	386,147	210.37	274.64	3032.92
May-17	1,403	204,448	132,180	72,267	205	352.1218	155	(17,688)	186,759	145.72	133.11	3041.27
Jun-17	1,396	159,579	159,579	0	33	0.0000	27	0	159,579	114.31	114.31	3081.09
Jul-17	1,394	148,670	148,670	0	2	0.0000	0	0	148,670	106.65	106.65	3060.46
Aug-17	1,392	163,113	154,124	8,989	19	476.4487	8	(5,177)	157,936	117.18	113.46	3061.27
Sep-17	1,385	221,802	154,124	67,678	89	757.1402	68	(16,192)	205,610	160.15	148.45	3070.34
Oct-17	1,385	223,477	154,124	69,353	227	305.0200	309	24,898	248,376	161.36	179.33	3080.37
Nov-17	1,388	447,600	154,124	293,476	684	429.1218	647	(15,834)	431,766	322.48	311.07	3095.48
Dec-17	1,388	696,001	154,124	541,877	1,087	498.3156	895	(95,884)	600,117	501.44	432.36	3129.65
Jan-18	1,392	721,051	154,124	566,927	1,156	490.5790	1,069	(42,498)	678,553	518.00	487.47	3096.21
Feb-18	1,392	534,083	154,124	379,959	775	490.5005	881	52,172	586,255	383.68	421.16	3080.00
Mar-18	1,387	582,242	154,124	428,118	905	473.2531	749	(73,651)	508,591	419.79	366.68	3088.71
Apr-18	1,384	472,037	154,124	317,912	573	555.0354	410	(90,348)	381,689	341.07	275.79	3089.85
May-18	1,379	84,079	84,079	0	69	0.0000	155	0	84,079	60.97	60.97	3017.71
Jun-18	1,371	138,638	138,638	0	29	0.0000	27	0	138,638	101.12	101.12	3004.52
Jul-18	1,367	114,004	114,004	0	2	0.0000	0	0	114,004	83.40	83.40	2981.27
Aug-18	1,362	149,081	149,081	0	2	0.0000	8	0	149,081	109.46	109.46	2977.26
Sep-18	1,357	149,840	149,460	380	61	6.2027	68	42	149,882	110.42	110.45	2939.26
Oct-18	1,362	257,484	149,460	108,023	370	291.9784	309	(17,802)	239,682	189.05	175.98	2935.91
Nov-18	1,371	415,083	149,460	265,622	773	343.8057	647	(43,180)	371,903	302.76	271.26	2896.10
Dec-18	1,377	551,550	149,460	402,090	886	453.8347	895	4,092	555,642	400.54	403.52	2867.25
Jan-19	1,379	750,209	149,460	600,748	1,146	524.1101	1,069	(40,475)	709,734	544.02	514.67	2894.46
Feb-19	1,379	594,303	149,460	444,842	904	492.0515	881	(11,345)	582,958	430.97	422.74	2896.04
Mar-19	1,375	560,195	149,460	410,734	826	497.4975	749	(38,109)	522,086	407.41	379.70	2909.05
Apr-19	1,368	286,879	149,460	137,418	319	430.2607	410	38,989	325,867	209.71	238.21	2871.48
May-19	1,361	188,433	149,460	38,972	121	322.6359	155	11,036	199,469	138.45	146.56	2957.06
Jun-19	1,360	147,024	147,024	0	25	0.0000	27	0	147,024	108.11	108.11	2964.05
Jul-19	1,357	142,937	142,937	0	1	0.0000	0	0	142,937	105.33	105.33	2985.98
Aug-19	1,355	149,519	149,519	0	2	0.0000	8	0	149,519	110.35	110.35	2986.87
Sep-19	1,363	109,383	109,383	0	29	0.0000	68	0	109,383	80.25	80.25	2956.67
Oct-19	1,361	204,246	146,228	58,018	266	218.0937	309	9,373	213,619	150.07	156.96	2937.65
Nov-19	1,365	449,810	146,228	303,582	764	397.5352	647	(46,377)	403,433	329.53	295.56	2961.94
Dec-19	1,361	524,407	146,228	378,180	923	409.7066	895	(11,492)	512,915	385.31	376.87	2935.29
Jan-20	1,358	650,037	146,228	503,810	916	550.2340	1,069	84,390	734,428	478.67	540.82	2961.44
Feb-20	1,357	584,713	146,228	438,485	822	533.4611	909	46,431	631,144	430.89	465.10	3003.80
Mar-20	1,350	302,642	146,228	156,414	595	263.0689	749	40,624	343,266	224.18	254.27	2878.37
Apr-20	1,341	237,334	146,228	91,106	488	186.7021	410	(14,558)	222,776	176.98	166.13	2806.29
May-20	1,337	323,903	146,228	177,675	217	224.8855	155	(13,948)	309,955	242.26	231.83	2891.56
Jun-20	1,337	6,152	6,152	0	13	0.0000	27	0	6,152	4.60	4.60	2788.05
Jul-20	1,330	99,166	99,166	0	0	0.0000	0	0	99,166	74.56	74.56	2757.28
Aug-20	1,323	107,058	107,058	0	0	0.0000	8	0	107,058	80.92	80.92	2727.86
Sep-20	1,330	133,855	133,855	0	88	0.0000	68	0	133,855	100.64	100.64	2748.25
Oct-20	1,334	201,824	146,228	55,596	309	179.9238	309	0	201,824	151.29	151.29	2742.58
Nov-20	1,331	289,168	146,228	142,941	507	281.9344	647	39,471	328,639	217.26	246.91	2693.94
Dec-20	1,332	502,064	146,228	355,836	940	378.5488	895	(17,035)	485,029	376.92	364.14	2681.21
Jan-21	1,341	600,851	146,228	454,623	1,025	443.5348	1,069	19,516	620,366	448.06	462.61	2603.01
Feb-21	1,342	556,338	146,228	410,110	969	423.2300	881	(37,244)	519,093	414.56	386.81	2524.71
Mar-21	1,344	463,550	146,228	317,322	649	488.9396	749	48,894	512,443	344.90	381.28	2651.72
Apr-21	1,340	254,490	146,228	108,262	388	279.0265	410	6,139	260,629	189.92	194.50	2680.10
May-21	1,331	222,012	146,228	75,784	204	371.4926	155	(18,203)	203,809	166.80	153.12	2601.39
Jun-21	1,326	87,783	87,783	0	12	0.0000	27	0	87,783	66.20	66.20	2662.99
Jul-21	1,329	126,619	126,619	0	0	0.0000	0	0	126,619	95.27	95.27	2683.71
Aug-21	1,330	136,505	136,505	0	0	0.0000	8	0	136,505	102.63	102.63	2705.42
Sep-21	1,328	130,853	130,853	0	53	0.0000	68	0	130,853	98.53	98.53	2703.31

UGI Utilities, Inc. - Gas Division
Industrial - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-21	1,332	193,800	131,562	62,239	183	340.1030	309	42,853	236,653	145.50	177.67	2,729.69
Nov-21	1,341	423,559	131,562	291,998	720	405.5527	647	(29,605)	393,954	315.85	293.78	2,776.55
Dec-21	1,338	523,239	131,562	391,678	759	516.0443	895	70,182	593,421	391.06	443.51	2,855.93
Jan-22	1,339	599,694	131,562	468,133	1,219	460.7985	1,069	(69,120)	530,574	447.87	396.25	2,789.56
Feb-22	1,338	543,867	131,562	412,306	867	475.5547	881	6,658	550,525	406.48	411.45	2,814.21
Mar-22	1,336	420,279	131,562	288,717	674	428.3636	749	32,127	452,406	314.58	338.63	2,771.55
Apr-22	1,336	285,789	131,562	154,228	450	342.7285	410	(13,709)	272,080	213.91	203.65	2,780.71
May-22	1,331	161,960	131,562	30,399	94	323.3897	155	19,727	181,687	121.68	136.50	2,764.09
Jun-22	1,329	133,123	131,562	1,562	6	260.2990	27	5,466	138,590	100.17	104.28	2,802.17
Jul-22	1,325	125,499	125,499	0	0	0.0000	0	0	125,499	94.72	94.72	2,801.61
Aug-22	1,321	138,855	138,855	0	0	0.0000	8	0	138,855	105.11	105.11	2,804.09
Sep-22	1,321	163,918	132,177	31,741	81	391.8609	68	(5,094)	158,823	124.09	120.23	2,825.78
Oct-22	1,314	218,638	132,177	86,461	378	228.7337	309	(15,783)	202,856	166.39	154.38	2,802.50
Nov-22	1,318	348,050	132,177	215,873	583	370.2790	647	23,698	371,747	264.07	282.05	2,790.77
Dec-22	1,321	562,794	132,177	430,617	964	446.6985	895	(30,822)	531,972	426.04	402.70	2,749.96
Jan-23	1,316	507,900	132,177	375,723	820	458.1986	1,069	114,091	621,991	385.94	472.64	2,826.35
Feb-23	1,320	482,868	132,177	350,692	748	468.8390	881	62,356	545,224	365.81	413.05	2,827.95
Mar-23	1,315	455,916	132,177	323,739	734	441.0608	749	6,616	462,531	346.70	351.73	2,841.06
Apr-23	1,313	219,512	132,177	87,335	311	280.8210	410	27,801	247,314	167.18	188.36	2,825.76
May-23	1,311	172,588	132,177	40,411	164	246.4084	155	(2,218)	170,370	131.65	129.95	2,819.21
Jun-23	1,307	124,287	124,287	0	21	0.0000	27	0	124,287	95.09	95.09	2,810.02
Jul-23	1,303	104,751	104,751	0	0	0.0000	0	0	104,751	80.39	80.39	2,795.70
Aug-23	1,302	107,901	107,901	0	1	0.0000	8	0	107,901	82.87	82.87	2,773.46
Sep-23	1,302	119,702	106,326	13,376	71	188.3957	68	(565)	119,137	91.94	91.50	2,744.73
Oct-23	1,304	175,944	106,326	69,618	289	240.8923	309	4,818	180,762	134.93	138.62	2,728.97
Nov-23	1,306	334,270	106,326	227,944	678	336.2009	647	(10,422)	323,848	255.95	247.97	2,694.89
Dec-23	1,308	402,651	106,326	296,324	756	391.9635	895	54,483	457,133	307.84	349.49	2,641.68
Jan-24	1,309	579,176	106,326	472,850	985	480.0508	1,069	40,324	619,500	442.46	473.26	2,642.30
Feb-24	1,306	428,504	106,326	322,178	815	395.3103	909	37,159	465,663	328.10	356.56	2,585.81
Mar-24	1,304	330,679	106,326	224,353	603	372.0612	749	54,321	385,000	253.59	295.25	2,529.32
Apr-24	1,299	263,726	106,326	157,400	341	461.5834	410	31,849	295,575	203.02	227.54	2,568.50
May-24	1,297	106,328	106,326	2	95	0.0241	155	1	106,330	81.98	81.98	2,520.53
Jun-24	1,295	92,214	92,214	0	4	0.0000	27	0	92,214	71.21	71.21	2,496.64
Jul-24	1,293	87,708	87,708	0	0	0.0000	0	0	87,708	67.83	67.83	2,484.08
Aug-24	1,289	93,642	93,642	0	12	0.0000	8	0	93,642	72.65	72.65	2,473.86
Sep-24	1,285	86,493	86,493	0	35	0.0000	68	0	86,493	67.31	67.31	2,449.67
Oct-24	1,289	143,216	87,101	56,116	278	201.8551	309	6,258	149,474	111.11	115.96	2,427.01
Nov-24	1,294	250,897	87,101	163,797	562	291.4531	647	24,774	275,671	193.89	213.04	2,392.07
Dec-24	1,298	478,643	87,101	391,542	957	409.1348	895	(25,366)	453,276	368.75	349.21	2,391.79
Jan-25	1,304	632,258	87,101	545,157	1,216	448.3202	1,069	(65,903)	566,355	484.86	434.32	2,352.85
Feb-25	1,300	532,287	87,101	445,187	941	473.0997	881	(28,386)	503,901	409.45	387.62	2,383.91
Mar-25	1,294	338,531	87,101	251,431	604	416.2762	749	60,360	398,891	261.62	308.26	2,396.93
Apr-25	1,292	209,943	87,101	122,842	359	342.1789	410	17,451	227,394	162.49	176.00	2,345.39
May-25	1,286	104,424	87,101	17,323	160	108.2711	155	(541)	103,883	81.20	80.78	2,344.19
Jun-25	1,283	81,976	81,976	0	20	0.0000	27	0	81,976	63.89	63.89	2,336.87
Jul-25	1,282	89,876	89,876	0	0	0.0000	0	0	89,876	70.11	70.11	2,339.15
Aug-25	1,275	73,081	73,081	0	24	0.0000	8	0	73,081	57.32	57.32	2,323.82
Sep-25	1,276	85,280	77,528	7,751	17	455.9671	68	23,254	108,534	66.83	85.06	2,341.57

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
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Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	511	54,511	26,563	27,947	335	83.3049	309	(2,206)	52,304	106.67	102.36	
Nov-12	505	100,881	26,563	74,318	785	94.7256	647	(13,031)	87,850	199.77	173.96	
Dec-12	504	121,743	26,563	95,180	853	111.5251	895	4,635	126,378	241.55	250.75	
Jan-13	498	148,705	26,563	122,142	1,047	116.6673	1,069	2,575	151,280	298.61	303.78	
Feb-13	498	151,707	26,563	125,144	974	128.4598	881	(11,971)	139,736	304.63	280.59	
Mar-13	492	123,833	26,563	97,270	884	110.0930	749	(14,810)	109,023	251.69	221.59	
Apr-13	485	74,867	26,563	48,304	427	113.1899	410	(1,896)	72,971	154.37	150.46	
May-13	479	38,578	26,563	12,015	178	67.3597	155	(1,575)	37,004	80.54	77.25	
Jun-13	475	25,638	25,638	0	21	0.0000	27	0	25,638	53.97	53.97	
Jul-13	470	27,363	27,363	0	4	0.0000	0	0	27,363	58.22	58.22	
Aug-13	466	29,901	26,501	3,400	12	52.2811	8	(225)	29,676	64.16	63.68	
Sep-13	452	30,929	26,501	4,429	143	31.0408	68	(2,318)	28,611	68.43	63.30	1799.91
Oct-13	450	50,569	26,501	24,068	327	73.5214	309	(1,350)	49,219	112.37	109.37	1806.93
Nov-13	453	103,788	26,501	77,287	773	99.9996	647	(12,587)	91,200	229.11	201.33	1834.29
Dec-13	461	142,792	26,501	116,291	1,012	114.9270	895	(13,432)	129,360	309.74	280.61	1864.15
Jan-14	461	190,198	26,501	163,697	1,310	124.9446	1,069	(30,131)	160,066	412.58	347.22	1907.59
Feb-14	461	169,059	26,501	142,558	1,114	127.9751	881	(29,812)	139,247	366.72	302.05	1929.05
Mar-14	454	156,725	26,501	130,224	976	133.3780	749	(30,324)	126,401	345.21	278.42	1985.88
Apr-14	444	71,045	26,501	44,544	467	95.4645	410	(5,404)	65,641	160.01	147.84	1983.26
May-14	443	43,235	26,501	16,735	152	109.7693	155	280	43,515	97.60	98.23	2004.24
Jun-14	441	32,901	26,501	6,401	14	102.6169	27	1,380	34,281	74.61	77.74	2028.00
Jul-14	437	29,971	29,971	0	10	0.0000	0	0	29,971	68.58	68.58	2038.36
Aug-14	436	31,425	31,425	0	13	0.0000	8	0	31,425	72.07	72.07	2046.75
Sep-14	440	31,552	30,698	854	98	8.6752	68	(264)	31,288	71.71	71.11	2054.56
Oct-14	444	48,633	30,698	17,935	303	59.2442	309	371	49,004	109.53	110.37	2055.56
Nov-14	444	102,465	30,698	71,767	759	94.5606	647	(10,586)	91,879	230.78	206.93	2061.17
Dec-14	444	136,845	30,698	106,147	909	116.7441	895	(1,661)	135,184	308.21	304.47	2085.03
Jan-15	447	170,827	30,698	140,129	1,231	113.8425	1,069	(18,431)	152,395	382.16	340.93	2078.74
Feb-15	447	188,116	30,698	157,419	1,275	123.4588	881	(48,651)	139,465	420.84	312.00	2088.69
Mar-15	445	142,415	30,698	111,717	960	116.3748	749	(24,552)	117,863	320.03	264.86	2075.13
Apr-15	446	62,580	30,698	31,882	403	79.0862	410	543	63,123	140.31	141.53	2068.82
May-15	450	36,639	30,698	5,941	83	71.7508	155	5,181	41,819	81.42	92.93	2063.53
Jun-15	455	30,684	30,684	0	32	0.0000	27	0	30,684	67.44	67.44	2053.23
Jul-15	458	29,406	29,406	0	4	0.0000	0	0	29,406	64.20	64.20	2048.85
Aug-15	459	28,550	28,550	0	6	0.0000	8	0	28,550	62.20	62.20	2038.98
Sep-15	463	27,877	27,877	0	42	0.0000	68	0	27,877	60.21	60.21	2028.08
Oct-15	461	53,537	28,978	24,559	378	64.9922	309	(4,476)	49,060	116.13	106.42	2024.13
Nov-15	459	79,115	28,978	50,137	508	98.6373	647	13,682	92,796	172.36	202.17	2019.37
Dec-15	462	88,815	28,978	59,837	625	95.7736	895	25,881	114,695	192.24	248.26	1963.16
Jan-16	465	156,916	28,978	127,938	1,130	113.2491	1,069	(6,875)	150,041	337.45	322.67	1944.90
Feb-16	467	147,053	28,978	118,075	936	126.1862	909	(3,372)	143,681	314.89	307.67	1940.56
Mar-16	465	92,982	28,978	64,004	582	110.0268	749	18,406	111,388	199.96	239.54	1915.25
Apr-16	461	61,898	28,978	32,920	468	70.3335	410	(4,083)	57,815	134.27	125.41	1899.13
May-16	462	36,320	28,978	7,342	221	33.2379	155	(2,190)	34,130	78.61	73.87	1880.07
Jun-16	459	26,905	26,905	0	25	0.0000	27	0	26,905	58.62	58.62	1871.25
Jul-16	456	23,100	23,100	0	2	0.0000	0	0	23,100	50.66	50.66	1857.70
Aug-16	458	25,427	25,427	0	3	0.0000	8	0	25,427	55.52	55.52	1851.02
Sep-16	456	27,464	26,166	1,298	53	24.7147	68	382	27,846	60.23	61.07	1851.87
Oct-16	454	46,899	26,166	20,734	324	64.0404	309	(945)	45,954	103.30	101.22	1846.67
Nov-16	457	80,004	26,166	53,838	589	91.4390	647	5,323	85,327	175.06	186.71	1831.21
Dec-16	453	135,276	26,166	109,111	973	112.1842	895	(8,706)	126,571	298.62	279.41	1862.36
Jan-17	453	159,622	26,166	133,457	961	138.8818	1,069	15,008	174,630	352.37	385.50	1925.19
Feb-17	445	118,403	26,166	92,238	719	128.3666	881	20,853	139,257	266.08	312.94	1930.46
Mar-17	443	121,736	26,166	95,570	879	108.6679	749	(14,178)	107,558	274.80	242.79	1933.71

UGI Utilities, Inc. - Gas Division
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Apr-17	438	53,078	26,166	26,912	264	101.8944	410	14,865	67,942	121.18	155.12	1963.42
May-17	441	36,238	26,166	10,072	205	49.0753	155	(2,465)	33,772	82.17	76.58	1966.12
Jun-17	445	25,809	25,809	0	33	0.0000	27	0	25,809	58.00	58.00	1965.51
Jul-17	449	24,244	24,244	0	2	0.0000	0	0	24,244	53.99	53.99	1968.84
Aug-17	449	25,276	25,276	0	19	0.0000	8	0	25,276	56.29	56.29	1969.62
Sep-17	453	26,556	24,760	1,796	89	20.0956	68	(430)	26,126	58.62	57.67	1966.23
Oct-17	453	23,203	23,203	0	227	0.0000	309	0	23,203	51.22	51.22	1916.23
Nov-17	452	103,201	24,760	78,441	684	114.6964	647	(4,232)	98,969	228.32	218.96	1948.47
Dec-17	461	129,284	24,760	104,524	1,087	96.1213	895	(18,495)	110,789	280.44	240.32	1909.39
Jan-18	464	167,668	24,760	142,908	1,156	123.6629	1,069	(10,713)	156,956	361.35	338.27	1862.16
Feb-18	464	134,664	24,760	109,904	775	141.8782	881	15,091	149,755	290.22	322.75	1871.97
Mar-18	465	129,004	24,760	104,244	905	115.2347	749	(17,934)	111,071	277.43	238.86	1868.04
Apr-18	470	90,708	24,760	65,948	573	115.1371	410	(18,742)	71,966	193.00	153.12	1866.04
May-18	470	32,541	24,760	7,781	69	113.3932	155	9,794	42,336	69.24	90.08	1879.53
Jun-18	470	26,484	24,760	1,724	29	59.8983	27	(107)	26,377	56.35	56.12	1877.66
Jul-18	472	26,133	26,133	0	2	0.0000	0	0	26,133	55.37	55.37	1879.03
Aug-18	469	36,084	36,084	0	2	0.0000	8	0	36,084	76.94	76.94	1899.67
Sep-18	462	27,657	27,657	0	61	0.0000	68	0	27,657	59.86	59.86	1901.86
Oct-18	468	52,014	31,109	20,906	370	56.5061	309	(3,445)	48,569	111.14	103.78	1954.42
Nov-18	474	87,334	31,109	56,226	773	72.7750	647	(9,140)	78,194	184.25	164.97	1900.43
Dec-18	482	126,687	31,109	95,579	886	107.8789	895	973	127,660	262.84	264.86	1924.96
Jan-19	484	194,677	31,109	163,569	1,146	142.7019	1,069	(11,020)	183,657	402.23	379.46	1966.15
Feb-19	482	166,566	31,109	135,458	904	149.8331	881	(3,455)	163,111	345.57	338.41	1981.81
Mar-19	477	142,121	31,109	111,013	826	134.4630	749	(10,300)	131,821	297.95	276.35	2019.30
Apr-19	479	70,837	31,109	39,728	319	124.3904	410	11,272	82,109	147.88	171.42	2037.60
May-19	479	52,792	31,109	21,684	121	179.5106	155	6,140	58,933	110.21	123.03	2070.56
Jun-19	476	33,215	31,109	2,107	25	84.6143	27	178	33,393	69.78	70.15	2084.59
Jul-19	474	31,451	31,451	0	1	0.0000	0	0	31,451	66.35	66.35	2095.57
Aug-19	476	34,757	34,757	0	2	0.0000	8	0	34,757	73.02	73.02	2091.66
Sep-19	476	26,167	26,167	0	29	0.0000	68	0	26,167	54.97	54.97	2086.77
Oct-19	476	41,633	33,104	8,528	266	32.0586	309	1,378	43,010	87.46	90.36	2073.34
Nov-19	477	107,387	33,104	74,283	764	97.2720	647	(11,348)	96,039	225.13	201.34	2109.72
Dec-19	476	124,495	33,104	91,390	923	99.0092	895	(2,777)	121,717	261.54	255.71	2100.57
Jan-20	477	188,914	33,104	155,810	916	170.1670	1,069	26,099	215,013	396.05	450.76	2171.88
Feb-20	477	157,427	33,104	124,322	822	151.2507	909	13,164	170,591	330.04	357.63	2191.10
Mar-20	480	110,910	33,104	77,806	595	130.8602	749	20,208	131,119	231.06	273.16	2187.91
Apr-20	480	84,141	33,104	51,036	488	104.5878	410	(8,155)	75,985	175.29	158.30	2174.80
May-20	478	53,570	33,104	20,465	217	94.2997	155	(5,849)	47,721	112.07	99.83	2151.60
Jun-20	478	37,163	33,104	4,059	13	99.4437	27	1,377	38,540	77.75	80.63	2162.07
Jul-20	474	21,284	21,284	0	0	0.0000	0	0	21,284	44.90	44.90	2140.62
Aug-20	468	26,360	26,360	0	0	0.0000	8	0	26,360	56.32	56.32	2123.93
Sep-20	469	33,885	23,822	10,063	88	114.6175	68	(2,269)	31,616	72.25	67.41	2136.37
Oct-20	468	53,909	23,822	30,086	309	97.3669	309	0	53,909	115.19	115.19	2161.20
Nov-20	466	75,394	23,822	51,572	507	101.7203	647	14,241	89,635	161.79	192.35	2152.21
Dec-20	467	143,204	23,822	119,381	940	127.0016	895	(5,715)	137,489	306.65	294.41	2190.91
Jan-21	461	182,239	23,822	158,417	1,025	154.5529	1,069	6,800	189,039	395.31	410.06	2150.21
Feb-21	463	168,167	23,822	144,345	969	148.9629	881	(13,109)	155,058	363.21	334.90	2127.48
Mar-21	458	109,638	23,822	85,816	649	132.2285	749	13,223	122,861	239.39	268.26	2122.57
Apr-21	456	74,328	23,822	50,506	388	130.1689	410	2,864	77,191	163.00	169.28	2133.55
May-21	449	43,777	23,822	19,955	204	97.8179	155	(4,793)	38,984	97.50	86.82	2120.54
Jun-21	450	29,594	23,822	5,772	12	113.9934	27	1,710	31,304	65.76	69.56	2109.47
Jul-21	449	30,916	30,916	0	0	0.0000	0	0	30,916	68.86	68.86	2133.43
Aug-21	446	32,165	32,165	0	0	0.0000	8	0	32,165	72.12	72.12	2149.22
Sep-21	441	30,033	30,033	0	53	0.0000	68	0	30,033	68.10	68.10	2149.91

UGI Utilities, Inc. - Gas Division
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Oct-21	446	45,601	30,255	15,346	183	83.8594	309	10,566	56,167	102.24	125.94	2,160.66
Nov-21	449	105,053	30,255	74,798	720	103.8863	647	(7,584)	97,469	233.97	217.08	2,185.39
Dec-21	452	122,635	30,255	92,380	759	121.7125	895	16,553	139,188	271.32	307.94	2,198.92
Jan-22	448	185,511	30,255	155,256	1,219	127.3632	1,069	(19,104)	166,406	414.09	371.44	2,160.30
Feb-22	449	147,035	30,255	116,780	867	134.6939	881	1,886	148,920	327.47	331.67	2,157.07
Mar-22	451	114,478	30,255	84,223	674	124.9594	749	9,372	123,850	253.83	274.61	2,163.42
Apr-22	449	70,358	30,255	40,103	450	89.1179	410	(3,565)	66,793	156.70	148.76	2,142.90
May-22	451	32,864	30,255	2,609	94	27.7592	155	1,693	34,558	72.87	76.62	2,132.70
Jun-22	452	28,882	28,882	0	6	0.0000	27	0	28,882	63.90	63.90	2,127.04
Jul-22	447	26,354	26,354	0	0	0.0000	0	0	26,354	58.96	58.96	2,117.14
Aug-22	445	25,448	25,448	0	0	0.0000	8	0	25,448	57.19	57.19	2,102.21
Sep-22	440	36,013	25,901	10,112	81	124.8384	68	(1,623)	34,390	81.85	78.16	2,112.27
Oct-22	435	59,319	25,901	33,417	378	88.4060	309	(6,100)	53,219	136.36	122.34	2,108.67
Nov-22	429	85,181	25,901	59,280	583	101.6808	647	6,508	91,689	198.56	213.73	2,105.32
Dec-22	431	162,487	25,901	136,586	964	141.6862	895	(9,776)	152,710	377.00	354.32	2,151.70
Jan-23	429	122,339	25,901	96,438	820	117.6076	1,069	29,284	151,624	285.17	353.43	2,133.69
Feb-23	438	123,694	25,901	97,793	748	130.7394	881	17,388	141,083	282.41	322.11	2,124.12
Mar-23	454	111,219	25,901	85,318	734	116.2368	749	1,744	112,962	244.98	248.82	2,098.33
Apr-23	460	59,588	25,901	33,687	311	108.3180	410	10,723	70,311	129.54	152.85	2,102.42
May-23	464	46,452	25,901	20,550	164	125.3075	155	(1,128)	45,324	100.11	97.68	2,123.48
Jun-23	469	39,130	25,901	13,229	21	116.8127	27	701	39,831	83.43	84.93	2,144.50
Jul-23	469	27,926	27,926	0	0	0.0000	0	0	27,926	59.54	59.54	2,145.09
Aug-23	471	23,189	23,189	0	1	0.0000	8	0	23,189	49.23	49.23	2,137.14
Sep-23	473	30,446	25,558	4,888	71	68.8454	68	(207)	30,239	64.37	63.93	2,122.91
Oct-23	475	50,156	25,558	24,598	289	85.1142	309	1,702	51,858	105.59	109.18	2,109.74
Nov-23	477	104,641	25,558	79,083	678	116.6423	647	(3,616)	101,025	219.37	211.79	2,107.81
Dec-23	484	120,603	25,558	95,045	756	125.7212	895	17,475	138,078	249.18	285.29	2,038.78
Jan-24	485	177,686	25,558	152,128	985	154.4444	1,069	12,973	190,659	366.36	393.11	2,078.46
Feb-24	483	141,191	25,558	115,634	815	141.8816	909	13,337	154,528	292.32	319.93	2,076.29
Mar-24	477	105,202	25,558	79,644	603	132.0793	749	19,284	124,485	220.55	260.98	2,088.44
Apr-24	466	64,143	25,558	38,585	341	113.1530	410	7,808	71,951	137.65	154.40	2,089.99
May-24	462	28,319	25,558	2,761	95	29.0656	155	1,744	30,063	61.30	65.07	2,057.39
Jun-24	463	24,884	24,884	0	4	0.0000	27	0	24,884	53.75	53.75	2,026.20
Jul-24	462	21,770	21,770	0	0	0.0000	0	0	21,770	47.12	47.12	2,013.78
Aug-24	461	22,838	22,838	0	12	0.0000	8	0	22,838	49.54	49.54	2,014.09
Sep-24	457	22,303	22,303	0	35	0.0000	68	0	22,303	48.80	48.80	1,998.96
Oct-24	459	42,092	22,037	20,055	278	72.1398	309	2,236	44,328	91.70	96.58	1,986.36
Nov-24	460	84,310	22,037	62,273	562	110.8055	647	9,418	93,728	183.28	203.76	1,978.32
Dec-24	462	156,023	22,037	133,986	957	140.0061	895	(8,680)	147,342	337.71	318.92	2,011.96
Jan-25	465	207,651	22,037	185,614	1,216	152.6433	1,069	(22,439)	185,213	446.56	398.31	2,017.15
Feb-25	463	170,358	22,037	148,321	941	157.6203	881	(9,457)	160,900	367.94	347.52	2,044.74
Mar-25	464	98,938	22,037	76,902	604	127.3204	749	18,461	117,400	213.23	253.02	2,036.78
Apr-25	456	60,957	22,037	38,921	359	108.4138	410	5,529	66,486	133.68	145.80	2,028.18
May-25	451	32,749	22,037	10,712	160	66.9530	155	(335)	32,415	72.61	71.87	2,034.98
Jun-25	449	26,594	22,037	4,557	20	87.6834	27	614	27,208	59.23	60.60	2,041.83
Jul-25	447	22,676	22,676	0	0	0.0000	0	0	22,676	50.73	50.73	2,045.44
Aug-25	450	24,409	24,409	0	24	0.0000	8	0	24,409	54.24	54.24	2,050.14
Sep-25	447	23,498	23,498	0	17	0.0000	68	0	23,498	52.57	52.57	2,053.91

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Industrial - Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-26	180	91,781	509.9
Nov-26	180	139,391	774.4
Dec-26	180	202,102	1,122.8
Jan-27	180	252,493	1,402.7
Feb-27	180	233,748	1,298.6
Mar-27	180	197,677	1,098.2
Apr-27	180	128,751	715.3
May-27	180	86,544	480.8
Jun-27	180	68,355	379.7
Jul-27	180	59,409	330.0
Aug-27	180	61,031	339.1
Sep-27	180	64,893	360.5
Total			8,812.1

SDR-RR-6

Request:

If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by month by rate schedule from the beginning of the historic test year and the future test year through the most recent month available and update as additional data become available. Separately identify sales and transportation throughput and provide the work papers which develop normalized sales.

Response:

Please see the response to SDR-RR-5.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-7

Request:

Please provide the work paper developing the Company's FTY load growth adjustment.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-8

Request:

Please provide a complete copy of the computer output generated by the Company's statistical analysis package for all residential, commercial, public authority and industrial econometric models of gas demand estimated by the Company, but not presented in the filing.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-9

Request:

Identify the historical data source(s) for each dependent and independent variable utilized to develop the econometric models of gas demands for each forecasted customer group.

Response:

The variables noted below were utilized for the development of normalized and annualized usage for the Residential Heating ("RH") and Commercial Heating ("CH") customer groups, except as noted. Budgeting representing normalized and annualized usage was performed on an individual customer basis for Rate DS, Rate LFD, Rate XD and Rate IS by UGI Marketing personnel, with the exception of any new customer additions or losses for Rates LFD, XD and IS. The RH customer group is comprised of heating customers within Rates R and RT and the CH customer group is comprised of heating customers within Rates N, NT and DS.

(1) Monthly Use Per Customer ("UPC") – Monthly UPC is a dependent variable in the econometric model. The use per customer was developed from reported monthly sales (in MCF) and customer counts.

(2) Monthly Heating Degree Days – Actual monthly Heating Degree Days ("HDD") is an independent variable. HDD are calculated on a 65 degree Fahrenheit temperature base using the daily average temperature of a Gas Day and then summed by month to arrive at the Monthly Heating Degree Days. Each Gas Day is based upon the North American Standards Board definition of a Gas Day which encompasses the 24 hour period from 10:00 a.m. to 10:00 a.m. The recording locations for temperature weather data used to calculate HDD for UGI Gas are the NOAA recording stations at: Wilkes-Barre/Scranton, PA (KAVP); Allentown, PA (KABE); Reading, PA (KRDG); Lancaster, PA (KLNS); Harrisburg, PA (KMDT), Altoona, PA (KAOO), Clearfield, PA (KFIG), and Bradford, PA (KBFD). Weighting of stations is based on historical throughput within geographic delivery regions to produce a composite HDD combined value.

(3) Lagged Monthly Heating Degree Days – Monthly Heating Degree Days lagged by one month.

SDR-RR-9 (Continued)

(4) Weighted Time Trend – Weighted Time Trend is an independent variable. This variable captures trends in customer usage which include both known and unknown factors such as structural conservation related to more efficient building envelop construction, regular cycle appliance change-outs to more efficient units, upgrades to more efficient units, installation of energy conservation measures such as set-back thermostats and manual consumer behavior changes such as lowering thermostat settings in response to higher energy prices. This numeric variable represents the passage of time by assigning each monthly time period a sequential numeric value. This variable is weighted by the HDD and lagged HDD, equally, in order to capture trend impacts occurring across billing periods. This variable is used for the RH group forecasting (Rates R and RT) but is excluded for the CH group forecasting (including Rates N, NT and DS).

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-10

Request:

Identify the source(s) and supporting documentation for the FTY value of each independent variable which required forecasting in the Company's gas demand models.

Response:

(1) Monthly Customers – Monthly customer counts utilized are produced by a Marketing department forecast through the Fully Projected Future Test Year. Attachment SDR-RR-11 provides the supporting data.

(2) Monthly Heating Degree Days – Normal Monthly Heating Degree Days ("HDD") are utilized for forecasting. UGI Gas now utilizes a 10-year Normal HDD which is based on officially recorded daily temperatures (on a Gas Day basis) over the period January 1, 2015 to December 31, 2024. The Normal HDD are scheduled to be recalculated upon each rate case based upon the most recent calendar period data ending 12 months prior to the rate case filing date. The actual system HDD is calculated using temperature data as identified in SDR-RR-9. Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 10, UGI Gas Exhibit SAE-2 for Normal HDD values. Please see the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11, for supporting detail on the determination of Normal HDD values and the frequency of Normal HDD updates.

(3) Lagged Monthly Heating Degree Days – Lagged Monthly Heating Degree Days are equal to the Monthly Heating Degree Days and are representative of the prior month's Heating Degree Days.

(4) Weighted Time Trend – The Weighted Time Trend variable is sequenced a unit value of 1 each month through the regression period and forecast based on a continuation of that same sequence for each forecast month (e.g., 100, 101, 102, etc.). A weighting of the time trend is accomplished by multiplying the trend value by the applicable monthly average of HDD and lagged HDD and dividing that product by a value of 10,000 in order to normalize to a smaller sequential value for display. This variable is used for the RH group forecasting (Rates R and RT) but is excluded for the CH group forecasting (including Rates N, NT and DS).

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-11

Request:

Please provide in hard copy and on a computer diskette in Lotus 1-2-3, QuattroPro or other spreadsheet format, the dependent and independent variable databases relied upon to produce the Company's gas demand models. For variables based on averages, include the observations which comprise the average (e.g., gas prices).

Response:

Please see Attachments SDR-RR-11(a) and SDR-RR-11(b) which have been provided in print and electronic (Excel) format and uploaded to the Commission’s SharePoint site. Those materials will be served upon the parties via a secure OneDrive link.

Prepared by or under the supervision of: Sherry A. Epler

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Oct-03	455	309	72	455	3	100	Oct-03	7.01
Nov-03	574	647	455	574	5	101	Nov-03	8.86
Dec-03	999	895	574	999	8	102	Dec-03	16.34
Jan-04	1,357	1,069	999	1,357	12	103	Jan-04	22.18
Feb-04	983	881	1,357	983	12	104	Feb-04	17.88
Mar-04	736	749	983	736	9	105	Mar-04	13.14
Apr-04	438	410	736	438	6	106	Apr-04	8.34
May-04	97	155	438	97	3	107	May-04	3.16
Jun-04	52	27	97	52	1	108	Jun-04	2.03
Jul-04	1	0	52	1	0	109	Jul-04	1.89
Aug-04	21	8	1	21	0	110	Aug-04	1.80
Sep-04	59	68	21	59	0	111	Sep-04	2.19
Oct-04	416	309	59	416	3	112	Oct-04	6.07
Nov-04	627	647	416	627	6	113	Nov-04	9.15
Dec-04	1,005	895	627	1,005	9	114	Dec-04	14.46
Jan-05	1,217	1,069	1,005	1,217	13	115	Jan-05	19.65
Feb-05	939	881	1,217	939	13	116	Feb-05	16.19
Mar-05	942	749	939	942	11	117	Mar-05	15.53
Apr-05	377	410	942	377	8	118	Apr-05	7.66
May-05	268	155	377	268	4	119	May-05	4.88
Jun-05	16	27	268	16	2	120	Jun-05	1.64
Jul-05	0	0	16	0	0	121	Jul-05	1.68
Aug-05	1	8	0	1	0	122	Aug-05	1.61
Sep-05	35	68	1	35	0	123	Sep-05	1.94
Oct-05	351	309	35	351	2	124	Oct-05	5.06
Nov-05	600	647	351	600	6	125	Nov-05	8.67
Dec-05	1,121	895	600	1,121	11	126	Dec-05	16.99
Jan-06	890	1,069	1,121	890	13	127	Jan-06	13.77
Feb-06	945	881	890	945	12	128	Feb-06	14.80
Mar-06	775	749	945	775	11	129	Mar-06	12.33
Apr-06	390	410	775	390	8	130	Apr-06	6.39
May-06	184	155	390	184	4	131	May-06	3.21
Jun-06	44	27	184	44	2	132	Jun-06	1.94
Jul-06	1	0	44	1	0	133	Jul-06	1.77
Aug-06	5	8	1	5	0	134	Aug-06	1.40
Sep-06	123	68	5	123	1	135	Sep-06	2.19
Oct-06	428	309	123	428	4	136	Oct-06	5.82
Nov-06	552	647	428	552	7	137	Nov-06	7.70
Dec-06	813	895	552	813	9	138	Dec-06	11.76
Jan-07	997	1,069	813	997	13	139	Jan-07	15.35
Feb-07	1,178	881	997	1,178	15	140	Feb-07	18.66
Mar-07	824	749	1,178	824	14	141	Mar-07	13.25
Apr-07	552	410	824	552	10	142	Apr-07	9.24
May-07	142	155	552	142	5	143	May-07	3.14
Jun-07	23	27	142	23	1	144	Jun-07	1.81
Jul-07	13	0	23	13	0	145	Jul-07	1.64
Aug-07	22	8	13	22	0	146	Aug-07	1.58
Sep-07	72	68	22	72	1	147	Sep-07	1.92
Oct-07	222	309	72	222	2	148	Oct-07	3.22
Nov-07	739	647	222	739	7	149	Nov-07	10.25
Dec-07	1,006	895	739	1,006	13	150	Dec-07	14.87
Jan-08	1,051	1,069	1,006	1,051	16	151	Jan-08	16.04
Feb-08	975	881	1,051	975	15	152	Feb-08	15.41
Mar-08	819	749	975	819	14	153	Mar-08	12.67
Apr-08	371	410	819	371	9	154	Apr-08	5.84
May-08	275	155	371	275	5	155	May-08	4.04
Jun-08	18	27	275	18	2	156	Jun-08	1.89
Jul-08	0	0	18	0	0	157	Jul-08	1.51
Aug-08	14	8	0	14	0	158	Aug-08	1.45
Sep-08	80	68	14	80	1	159	Sep-08	1.86
Oct-08	468	309	80	468	4	160	Oct-08	5.73
Nov-08	721	647	468	721	10	161	Nov-08	9.47
Dec-08	1,016	895	721	1,016	14	162	Dec-08	14.70
Jan-09	1,292	1,069	1,016	1,292	19	163	Jan-09	19.71
Feb-09	927	881	1,292	927	18	164	Feb-09	13.89
Mar-09	774	749	927	774	14	165	Mar-09	11.74
Apr-09	419	410	774	419	10	166	Apr-09	6.66
May-09	179	155	419	179	5	167	May-09	3.14
Jun-09	41	27	179	41	2	168	Jun-09	2.11
Jul-09	15	0	41	15	0	169	Jul-09	1.56
Aug-09	16	8	15	16	0	170	Aug-09	1.40
Sep-09	118	68	16	118	1	171	Sep-09	2.14
Oct-09	440	309	118	440	5	172	Oct-09	5.23
Nov-09	571	647	440	571	9	173	Nov-09	6.91
Dec-09	1,055	895	571	1,055	14	174	Dec-09	15.08
Jan-10	1,157	1,069	1,055	1,157	19	175	Jan-10	17.36

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Feb-10	1,014	881	1,157	1,014	19	176	Feb-10	15.18
Mar-10	627	749	1,014	627	15	177	Mar-10	9.30
Apr-10	325	410	627	325	8	178	Apr-10	4.79
May-10	153	155	325	153	4	179	May-10	2.99
Jun-10	25	27	153	25	2	180	Jun-10	1.82
Jul-10	4	0	25	4	0	181	Jul-10	1.52
Aug-10	7	8	4	7	0	182	Aug-10	1.38
Sep-10	67	68	7	67	1	183	Sep-10	1.76
Oct-10	383	309	67	383	4	184	Oct-10	4.18
Nov-10	669	647	383	669	10	185	Nov-10	8.63
Dec-10	1,162	895	669	1,162	17	186	Dec-10	16.88
Jan-11	1,251	1,069	1,162	1,251	23	187	Jan-11	18.37
Feb-11	955	881	1,251	955	21	188	Feb-11	14.46
Mar-11	836	749	955	836	17	189	Mar-11	12.68
Apr-11	414	410	836	414	12	190	Apr-11	6.44
May-11	125	155	414	125	5	191	May-11	3.02
Jun-11	21	27	125	21	1	192	Jun-11	1.80
Jul-11	1	0	21	1	0	193	Jul-11	1.72
Aug-11	10	8	1	10	0	194	Aug-11	1.56
Sep-11	74	68	10	74	1	195	Sep-11	2.11
Oct-11	400	309	74	400	5	196	Oct-11	5.30
Nov-11	559	647	400	559	9	197	Nov-11	7.40
Dec-11	843	895	559	843	14	198	Dec-11	12.05
Jan-12	1,002	1,069	843	1,002	18	199	Jan-12	15.24
Feb-12	814	881	1,002	814	18	200	Feb-12	12.26
Mar-12	487	749	814	487	13	201	Mar-12	6.81
Apr-12	437	410	487	437	9	202	Apr-12	6.26
May-12	73	155	437	73	5	203	May-12	2.07
Jun-12	39	27	73	39	1	204	Jun-12	1.83
Jul-12	1	0	39	1	0	205	Jul-12	1.42
Aug-12	7	8	1	7	0	206	Aug-12	1.37
Sep-12	110	68	7	110	1	207	Sep-12	2.29
Oct-12	335	309	110	335	5	208	Oct-12	4.09
Nov-12	785	647	335	785	12	209	Nov-12	11.60
Dec-12	853	895	785	853	17	210	Dec-12	11.90
Jan-13	1,047	1,069	853	1,047	20	211	Jan-13	16.20
Feb-13	974	881	1,047	974	21	212	Feb-13	14.45
Mar-13	884	749	974	884	20	213	Mar-13	13.19
Apr-13	427	410	884	427	14	214	Apr-13	5.17
May-13	178	155	427	178	7	215	May-13	2.98
Jun-13	21	27	178	21	2	216	Jun-13	1.73
Jul-13	4	0	21	4	0	217	Jul-13	1.80
Aug-13	12	8	4	12	0	218	Aug-13	1.66
Sep-13	143	68	12	143	2	219	Sep-13	2.57
Oct-13	327	309	143	327	5	220	Oct-13	4.42
Nov-13	773	647	327	773	12	221	Nov-13	11.13
Dec-13	1,012	895	773	1,012	20	222	Dec-13	14.53
Jan-14	1,310	1,069	1,012	1,310	26	223	Jan-14	20.39
Feb-14	1,114	881	1,310	1,114	27	224	Feb-14	16.28
Mar-14	976	749	1,114	976	24	225	Mar-14	14.25
Apr-14	467	410	976	467	16	226	Apr-14	6.54
May-14	152	155	467	152	7	227	May-14	2.58
Jun-14	14	27	152	14	2	228	Jun-14	1.68
Jul-14	10	0	14	10	0	229	Jul-14	1.44
Aug-14	13	8	10	13	0	230	Aug-14	1.45
Sep-14	98	68	13	98	1	231	Sep-14	2.99
Oct-14	303	309	98	303	5	232	Oct-14	3.75
Nov-14	759	647	303	759	12	233	Nov-14	11.30
Dec-14	909	895	759	909	20	234	Dec-14	12.93
Jan-15	1,231	1,069	909	1,231	25	235	Jan-15	19.42
Feb-15	1,275	881	1,231	1,275	30	236	Feb-15	19.74
Mar-15	960	749	1,275	960	26	237	Mar-15	13.96
Apr-15	403	410	960	403	16	238	Apr-15	6.14
May-15	83	155	403	83	6	239	May-15	2.37
Jun-15	32	27	83	32	1	240	Jun-15	1.93
Jul-15	4	0	32	4	0	241	Jul-15	1.60
Aug-15	6	8	4	6	0	242	Aug-15	1.62
Sep-15	42	68	6	42	1	243	Sep-15	1.83
Oct-15	378	309	42	378	5	244	Oct-15	5.02
Nov-15	508	647	378	508	11	245	Nov-15	7.01
Dec-15	625	895	508	625	14	246	Dec-15	8.57
Jan-16	1,130	1,069	625	1,130	22	247	Jan-16	17.77
Feb-16	936	881	1,130	936	26	248	Feb-16	13.92
Mar-16	582	749	936	582	19	249	Mar-16	8.82
Apr-16	468	410	582	468	13	250	Apr-16	6.85
May-16	221	155	468	221	9	251	May-16	3.34

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Jun-16	25	27	221	25	3	252	Jun-16	2.10
Jul-16	2	0	25	2	0	253	Jul-16	1.49
Aug-16	3	8	2	3	0	254	Aug-16	1.26
Sep-16	53	68	3	53	1	255	Sep-16	1.54
Oct-16	324	309	53	324	5	256	Oct-16	4.34
Nov-16	589	647	324	589	12	257	Nov-16	8.46
Dec-16	973	895	589	973	20	258	Dec-16	14.74
Jan-17	961	1,069	973	961	25	259	Jan-17	14.22
Feb-17	719	881	961	719	22	260	Feb-17	11.19
Mar-17	879	749	719	879	21	261	Mar-17	14.05
Apr-17	264	410	879	264	15	262	Apr-17	3.97
May-17	205	155	264	205	6	263	May-17	3.44
Jun-17	33	27	205	33	3	264	Jun-17	2.08
Jul-17	2	0	33	2	0	265	Jul-17	1.40
Aug-17	19	8	2	19	0	266	Aug-17	0.96
Sep-17	89	68	19	89	1	267	Sep-17	2.74
Oct-17	227	309	89	227	4	268	Oct-17	3.30
Nov-17	684	647	227	684	12	269	Nov-17	9.75
Dec-17	1,087	895	684	1,087	24	270	Dec-17	17.23
Jan-18	1,156	1,069	1,087	1,156	30	271	Jan-18	18.68
Feb-18	775	881	1,156	775	26	272	Feb-18	12.11
Mar-18	905	749	775	905	23	273	Mar-18	13.44
Apr-18	573	410	905	573	20	274	Apr-18	8.50
May-18	69	155	573	69	9	275	May-18	2.01
Jun-18	29	27	69	29	1	276	Jun-18	1.69
Jul-18	2	0	29	2	0	277	Jul-18	1.26
Aug-18	2	8	2	2	0	278	Aug-18	1.23
Sep-18	61	68	2	61	1	279	Sep-18	1.62
Oct-18	370	309	61	370	6	280	Oct-18	5.09
Nov-18	773	647	370	773	16	281	Nov-18	11.98
Dec-18	886	895	773	886	23	282	Dec-18	13.51
Jan-19	1,146	1,069	886	1,146	29	283	Jan-19	17.76
Feb-19	904	881	1,146	904	29	284	Feb-19	15.02
Mar-19	826	749	904	826	25	285	Mar-19	12.23
Apr-19	319	410	826	319	16	286	Apr-19	4.93
May-19	121	155	319	121	6	287	May-19	2.76
Jun-19	25	27	121	25	2	288	Jun-19	1.58
Jul-19	1	0	25	1	0	289	Jul-19	1.34
Aug-19	2	8	1	2	0	290	Aug-19	1.26
Sep-19	29	68	2	29	0	291	Sep-19	1.76
Oct-19	266	309	29	266	4	292	Oct-19	3.56
Nov-19	764	647	266	764	15	293	Nov-19	10.72
Dec-19	923	895	764	923	25	294	Dec-19	15.85
Jan-20	916	1,069	923	916	27	295	Jan-20	14.34
Feb-20	822	881	916	822	26	296	Feb-20	11.86
Mar-20	595	749	822	595	21	297	Mar-20	8.64
Apr-20	488	410	595	488	16	298	Apr-20	8.06
May-20	217	155	488	217	11	299	May-20	3.86
Jun-20	13	27	217	13	3	300	Jun-20	1.86
Jul-20	0	0	13	0	0	301	Jul-20	1.57
Aug-20	0	8	0	0	0	302	Aug-20	1.02
Sep-20	88	68	0	88	1	303	Sep-20	1.75
Oct-20	309	309	88	309	6	304	Oct-20	3.80
Nov-20	507	647	309	507	12	305	Nov-20	8.95
Dec-20	940	895	507	940	22	306	Dec-20	13.18
Jan-21	1,025	1069	940	1,025	30	307	Jan-21	16.25
Feb-21	969	881	1,025	969	31	308	Feb-21	15.31
Mar-21	649	749	969	649	25	309	Mar-21	10.25
Apr-21	388	410	649	388	16	310	Apr-21	5.84
May-21	204	155	388	204	9	311	May-21	3.15
Jun-21	12	27	204	12	3	312	Jun-21	1.52
Jul-21	0	0	12	0	0	313	Jul-21	1.48
Aug-21	0	8	0	0	0	314	Aug-21	1.43
Sep-21	53	68	0	53	1	315	Sep-21	1.37
Oct-21	183	309	53	183	4	316	Oct-21	2.57
Nov-21	720	647	183	720	14	317	Nov-21	10.53
Dec-21	759	895	720	759	24	318	Dec-21	11.73
Jan-22	1219	1069	759	1,219	32	319	Jan-22	19.49
Feb-22	867	881	1,219	867	33	320	Feb-22	13.78
Mar-22	674	749	867	674	25	321	Mar-22	10.27
Apr-22	450	410	674	450	18	322	Apr-22	6.55
May-22	94	155	450	94	9	323	May-22	2.56
Jun-22	6	27	94	6	2	324	Jun-22	1.63
Jul-22	0	0	6	0	0	325	Jul-22	1.31
Aug-22	0	8	0	0	0	326	Aug-22	1.08
Sep-22	81	68	0	81	1	327	Sep-22	1.82

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Oct-22	378	309	81	378	8	328	Oct-22	4.45
Nov-22	583	647	378	583	16	329	Nov-22	8.71
Dec-22	964	895	583	964	26	330	Dec-22	14.64
Jan-23	820	1069	964	820	30	331	Jan-23	12.59
Feb-23	748	881	820	748	26	332	Feb-23	12.53
Mar-23	734	749	748	734	25	333	Mar-23	11.03
Apr-23	311	410	734	311	17	334	Apr-23	4.52
May-23	164	155	311	164	8	335	May-23	3.03
Jun-23	21	27	164	21	3	336	Jun-23	1.55
Jul-23	0	0	21	0	0	337	Jul-23	1.24
Aug-23	1	8	0	1	0	338	Aug-23	1.47
Sep-23	71	68	1	71	1	339	Sep-23	1.50
Oct-23	289	309	71	289	6	340	Oct-23	3.77
Nov-23	678	647	289	678	16	341	Nov-23	9.33
Dec-23	756	895	678	756	25	342	Dec-23	11.74
Jan-24	985	1069	756	985	30	343	Jan-24	15.15
Feb-24	815	881	985	815	31	344	Feb-24	12.17
Mar-24	603	749	815	603	24	345	Mar-24	9.21
Apr-24	341	410	603	341	16	346	Apr-24	5.42
May-24	95	155	341	95	8	347	May-24	2.32
Jun-24	4	27	95	4	2	348	Jun-24	1.55
Jul-24	0	0	4	0	0	349	Jul-24	1.34
Aug-24	12	8	0	12	0	350	Aug-24	1.39
Sep-24	35	68	12	35	1	351	Sep-24	1.10
Oct-24	278	309	35	278	6	352	Oct-24	3.62
Nov-24	562	647	278	562	15	353	Nov-24	7.52
Dec-24	957	895	562	957	27	354	Dec-24	14.49
Jan-25	1216	1069	957	1,216	39	355	Jan-25	18.73
Feb-25	941	881	1,216	941	38	356	Feb-25	14.69
Mar-25	604	749	941	604	28	357	Mar-25	8.92
Apr-25	359	410	604	359	17	358	Apr-25	5.45
May-25	160	155	359	160	9	359	May-25	2.42
Jun-25	20	27	160	20	3	360	Jun-25	1.36
Jul-25	0	0	20	0	0	361	Jul-25	1.24
Aug-25	24	8	0	24	0	362	Aug-25	1.42
Sep-25	17	68	24	17	1	363	Sep-25	1.17
Oct-25		309	17	0	0	364		
Nov-25		647	0	0	0	365		
Dec-25		895	0	0	0	366		
Jan-26		1069	0	0	0	367		
Feb-26		881	0	0	0	368		
Mar-26		749	0	0	0	369		
Apr-26		410	0	0	0	370		
May-26		155	0	0	0	371		
Jun-26		27	0	0	0	372		
Jul-26		0	0	0	0	373		
Aug-26		8	0	0	0	374		
Sep-26		68	0	0	0	375		
Oct-26		309	0	0	0	376		
Nov-26		647	0	0	0	377		
Dec-26		895	0	0	0	378		
Jan-27		1069	0	0	0	379		
Feb-27		881	0	0	0	380		
Mar-27		749	0	0	0	381		
Apr-27		410	0	0	0	382		
May-27		155	0	0	0	383		
Jun-27		27	0	0	0	384		
Jul-27		0	0	0	0	385		
Aug-27		8	0	0	0	386		
Sep-27		68	0	0	0	387		
Oct-27		309	0	0	0	388		
Nov-27		647	0	0	0	389		
Dec-27		895	0	0	0	390		
Jan-28		1069	0	0	0	391		
Feb-28		881	0	0	0	392		
Mar-28		749	0	0	0	393		

Regression Results:		
	0.8297812	Constant
	0.0010635	HDD-1
	0.0137997	HDD
	-0.025428	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Oct-03	309	68	2		5.12	
Nov-03	647	309	5		9.96	
Dec-03	895	647	8		13.67	
Jan-04	1,069	895	10		16.28	
Feb-04	881	1,069	10		13.87	
Mar-04	749	881	9		11.89	
Apr-04	410	749	6		7.13	
May-04	155	410	3		3.33	
Jun-04	27	155	1		1.34	
Jul-04	0	27	0		0.85	
Aug-04	8	0	0		0.94	
Sep-04	68	8	0	FY04	1.77	86.14
Oct-04	309	68	2		5.11	86.13
Nov-04	647	309	5		9.95	86.12
Dec-04	895	647	9		13.65	86.09
Jan-05	1,069	895	11		16.25	86.06
Feb-05	881	1,069	11		13.84	86.03
Mar-05	749	881	10		11.86	86.01
Apr-05	410	749	7		7.11	85.99
May-05	155	410	3		3.32	85.98
Jun-05	27	155	1		1.34	85.98
Jul-05	0	27	0		0.85	85.98
Aug-05	8	0	0		0.94	85.98
Sep-05	68	8	0	FY05	1.76	85.98
Oct-05	309	68	2		5.11	85.97
Nov-05	647	309	6		9.93	85.96
Dec-05	895	647	10		13.62	85.93
Jan-06	1,069	895	12		16.22	85.90
Feb-06	881	1,069	12		13.81	85.87
Mar-06	749	881	11		11.84	85.85
Apr-06	410	749	8		7.09	85.83
May-06	155	410	4		3.31	85.82
Jun-06	27	155	1		1.34	85.82
Jul-06	0	27	0		0.85	85.82
Aug-06	8	0	0		0.94	85.82
Sep-06	68	8	1	FY06	1.76	85.82
Oct-06	309	68	3		5.10	85.81
Nov-06	647	309	7		9.92	85.80
Dec-06	895	647	11		13.60	85.77
Jan-07	1,069	895	14		16.19	85.74
Feb-07	881	1,069	14		13.78	85.71
Mar-07	749	881	11		11.81	85.69
Apr-07	410	749	8		7.07	85.67
May-07	155	410	4		3.30	85.66
Jun-07	27	155	1		1.33	85.66
Jul-07	0	27	0		0.85	85.66
Aug-07	8	0	0		0.94	85.66
Sep-07	68	8	1	FY 07	1.76	85.66
Oct-07	309	68	3		5.10	85.65
Nov-07	647	309	7		9.91	85.64
Dec-07	895	647	12		13.57	85.62
Jan-08	1,069	895	15		16.16	85.59
Feb-08	881	1,069	15		13.75	85.56
Mar-08	749	881	12		11.79	85.53
Apr-08	410	749	9		7.06	85.51
May-08	155	410	4		3.29	85.50
Jun-08	27	155	1		1.33	85.50
Jul-08	0	27	0		0.85	85.50
Aug-08	8	0	0		0.94	85.50
Sep-08	68	8	1	FY 08	1.76	85.50
Oct-08	309	68	3		5.09	85.49
Nov-08	647	309	8		9.89	85.48
Dec-08	895	647	12		13.55	85.46
Jan-09	1,069	895	16		16.13	85.43
Feb-09	881	1,069	16		13.72	85.40
Mar-09	749	881	13		11.76	85.37
Apr-09	410	749	10		7.04	85.35
May-09	155	410	5		3.28	85.34
Jun-09	27	155	2		1.33	85.34
Jul-09	0	27	0		0.85	85.34
Aug-09	8	0	0		0.94	85.34
Sep-09	68	8	1	FY 09	1.76	85.34
Oct-09	309	68	3		5.08	85.33
Nov-09	647	309	8		9.88	85.32
Dec-09	895	647	13		13.53	85.30
Jan-10	1,069	895	17		16.10	85.27
Feb-10	881	1,069	17		13.69	85.24

Regression Results:		
	0.8297812	Constant
	0.0010635	HDD-1
	0.0137997	HDD
	-0.025428	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Mar-10	749	881	14		11.74	85.21
Apr-10	410	749	10		7.02	85.19
May-10	155	410	5		3.28	85.19
Jun-10	27	155	2		1.33	85.18
Jul-10	0	27	0		0.85	85.18
Aug-10	8	0	0		0.94	85.18
Sep-10	68	8	1	FY 10	1.76	85.18
Oct-10	309	68	3		5.08	85.18
Nov-10	647	309	9		9.86	85.16
Dec-10	895	647	14		13.50	85.14
Jan-11	1,069	895	18		16.07	85.11
Feb-11	881	1,069	18		13.66	85.08
Mar-11	749	881	15		11.71	85.05
Apr-11	410	749	11		7.00	85.04
May-11	155	410	5		3.27	85.03
Jun-11	27	155	2		1.32	85.02
Jul-11	0	27	0		0.85	85.02
Aug-11	8	0	0		0.94	85.02
Sep-11	68	8	1	FY 11	1.76	85.02
Oct-11	309	68	4		5.07	85.02
Nov-11	647	309	9		9.85	85.00
Dec-11	895	647	15		13.48	84.98
Jan-12	1,069	895	20		16.04	84.95
Feb-12	881	1,069	20		13.63	84.92
Mar-12	749	881	16		11.69	84.89
Apr-12	410	749	12		6.99	84.88
May-12	155	410	6		3.26	84.87
Jun-12	27	155	2		1.32	84.86
Jul-12	0	27	0		0.85	84.86
Aug-12	8	0	0		0.94	84.86
Sep-12	68	8	1	FY 12	1.76	84.86
Oct-12	309	68	4		5.07	84.86
Nov-12	647	309	10		9.83	84.84
Dec-12	895	647	16		13.46	84.82
Jan-13	1,069	895	21		16.01	84.79
Feb-13	881	1,069	21		13.60	84.76
Mar-13	749	881	17		11.66	84.73
Apr-13	410	749	12		6.97	84.72
May-13	155	410	6		3.25	84.71
Jun-13	27	155	2		1.32	84.71
Jul-13	0	27	0		0.85	84.70
Aug-13	8	0	0		0.94	84.70
Sep-13	68	8	1	FY 13	1.76	84.70
Oct-13	309	68	4		5.06	84.70
Nov-13	647	309	11		9.82	84.68
Dec-13	895	647	17		13.43	84.66
Jan-14	1,069	895	22		15.98	84.63
Feb-14	881	1,069	22		13.57	84.60
Mar-14	749	881	18		11.64	84.58
Apr-14	410	749	13		6.95	84.56
May-14	155	410	6		3.24	84.55
Jun-14	27	155	2		1.31	84.55
Jul-14	0	27	0		0.85	84.55
Aug-14	8	0	0		0.94	84.55
Sep-14	68	8	1	FY 14	1.75	84.54
Oct-14	309	68	4		5.05	84.54
Nov-14	647	309	11		9.80	84.52
Dec-14	895	647	18		13.41	84.50
Jan-15	1,069	895	23		15.95	84.47
Feb-15	881	1,069	23		13.54	84.44
Mar-15	749	881	19		11.61	84.42
Apr-15	410	749	14		6.93	84.40
May-15	155	410	7		3.23	84.39
Jun-15	27	155	2		1.31	84.39
Jul-15	0	27	0		0.85	84.39
Aug-15	8	0	0		0.94	84.39
Sep-15	68	8	1	FY 15	1.75	84.39
Oct-15	309	68	5		5.05	84.38
Nov-15	647	309	12		9.79	84.36
Dec-15	895	647	19		13.39	84.34
Jan-16	1,069	895	24		15.92	84.31
Feb-16	881	1,069	24		13.51	84.28
Mar-16	749	881	20		11.59	84.26
Apr-16	410	749	14		6.92	84.24
May-16	155	410	7		3.22	84.23
Jun-16	27	155	2		1.31	84.23
Jul-16	0	27	0		0.85	84.23

Regression Results:		
	0.8297812	Constant
	0.0010635	HDD-1
	0.0137997	HDD
	-0.025428	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Aug-16	8	0	0		0.94	84.23
Sep-16	68	8	1	FY 16	1.75	84.23
Oct-16	309	68	5		5.04	84.22
Nov-16	647	309	12		9.77	84.21
Dec-16	895	647	20		13.36	84.18
Jan-17	1,069	895	25		15.89	84.15
Feb-17	881	1,069	25		13.48	84.12
Mar-17	749	881	21		11.56	84.10
Apr-17	410	749	15		6.90	84.08
May-17	155	410	7		3.22	84.07
Jun-17	27	155	2		1.31	84.07
Jul-17	0	27	0		0.85	84.07
Aug-17	8	0	0		0.94	84.07
Sep-17	68	8	1	FY 17	1.75	84.07
Oct-17	309	68	5		5.04	84.06
Nov-17	647	309	13		9.76	84.05
Dec-17	895	647	21		13.34	84.02
Jan-18	1,069	895	27		15.86	83.99
Feb-18	881	1,069	27		13.45	83.96
Mar-18	749	881	22		11.54	83.94
Apr-18	410	749	16		6.88	83.92
May-18	155	410	8		3.21	83.91
Jun-18	27	155	3		1.30	83.91
Jul-18	0	27	0		0.85	83.91
Aug-18	8	0	0		0.94	83.91
Sep-18	68	8	1	FY 18	1.75	83.91
Oct-18	309	68	5		5.03	83.90
Nov-18	647	309	13		9.75	83.89
Dec-18	895	647	22		13.32	83.86
Jan-19	1,069	895	28		15.83	83.83
Feb-19	881	1,069	28		13.42	83.80
Mar-19	749	881	23		11.51	83.78
Apr-19	410	749	17		6.86	83.76
May-19	155	410	8		3.20	83.75
Jun-19	27	155	3		1.30	83.75
Jul-19	0	27	0		0.85	83.75
Aug-19	8	0	0		0.94	83.75
Sep-19	68	8	1	FY 19	1.75	83.75
Oct-19	309	68	6		5.03	83.74
Nov-19	647	309	14		9.73	83.73
Dec-19	895	647	23		13.29	83.70
Jan-20	1,069	895	29		15.80	83.67
Feb-20	881	1,069	29		13.39	83.64
Mar-20	749	881	24		11.49	83.62
Apr-20	410	749	17		6.85	83.60
May-20	155	410	8		3.19	83.59
Jun-20	27	155	3		1.30	83.59
Jul-20	0	27	0		0.85	83.59
Aug-20	8	0	0		0.94	83.59
Sep-20	68	8	1	FY 20	1.75	83.59
Oct-20	309	68	6		5.02	83.58
Nov-20	647	309	15		9.72	83.57
Dec-20	895	647	24		13.27	83.55
Jan-21	1,069	895	30		15.77	83.52
Feb-21	881	1,069	30		13.36	83.49
Mar-21	749	881	25		11.46	83.46
Apr-21	410	749	18		6.83	83.44
May-21	155	410	9		3.18	83.43
Jun-21	27	155	3		1.30	83.43
Jul-21	0	27	0		0.85	83.43
Aug-21	8	0	0		0.94	83.43
Sep-21	68	8	1	FY 21	1.75	83.43
Oct-21	309	68	6		5.01	83.42
Nov-21	647	309	15		9.70	83.41
Dec-21	895	647	25		13.25	83.39
Jan-22	1,069	895	31		15.74	83.36
Feb-22	881	1,069	31		13.33	83.33
Mar-22	749	881	26		11.44	83.30
Apr-22	410	749	19		6.81	83.28
May-22	155	410	9		3.17	83.28
Jun-22	27	155	3		1.29	83.27
Jul-22	0	27	0		0.85	83.27
Aug-22	8	0	0		0.94	83.27
Sep-22	68	8	1	FY 22	1.75	83.27
Oct-22	309	68	6		5.01	83.26

Regression Results:		
	0.8297812	Constant
	0.0010635	HDD-1
	0.0137997	HDD
	-0.025428	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC	
Nov-22	647	309	16		9.69	83.25	
Dec-22	895	647	25		13.22	83.23	
Jan-23	1,069	895	33		15.71	83.20	
Feb-23	881	1,069	32		13.30	83.17	
Mar-23	749	881	27		11.41	83.14	
Apr-23	410	749	19		6.79	83.12	
May-23	155	410	9		3.16	83.12	
Jun-23	27	155	3		1.29	83.11	
Jul-23	0	27	0		0.85	83.11	
Aug-23	8	0	0		0.94	83.11	
Sep-23	68	8	1	FY 23	1.74	83.11	
Oct-23	309	68	6		5.00	83.11	
Nov-23	647	309	16		9.67	83.09	
Dec-23	895	647	26		13.20	83.07	
Jan-24	1,069	895	34		15.68	83.04	
Feb-24	881	1,069	34		13.27	83.01	
Mar-24	749	881	28		11.39	82.98	
Apr-24	410	749	20		6.77	82.97	
May-24	155	410	10		3.16	82.96	
Jun-24	27	155	3		1.29	82.95	
Jul-24	0	27	0		0.85	82.95	
Aug-24	8	0	0		0.94	82.95	
Sep-24	68	8	1	FY 24	1.74	82.95	
Oct-24	309	68	7		5.00	82.95	
Nov-24	647	309	17		9.66	82.93	
Dec-24	895	647	27		13.17	82.91	
Jan-25	1,069	895	35		15.65	82.88	
Feb-25	881	1,069	35		13.24	82.85	
Mar-25	749	881	29		11.36	82.82	
Apr-25	410	749	21		6.76	82.81	
May-25	155	410	10		3.15	82.80	
Jun-25	27	155	3		1.28	82.79	
Jul-25	0	27	0		0.85	82.79	
Aug-25	8	0	0		0.94	82.79	
Sep-25	68	8	1	FY 25	1.74	82.79	
Oct-25	309	68	7		4.99	82.79	
Nov-25	647	309	17		9.64	82.77	
Dec-25	895	647	28		13.15	82.75	
Jan-26	1,069	895	36		15.62	82.72	
Feb-26	881	1,069	36		13.21	82.69	
Mar-26	749	881	30		11.34	82.66	Historic Test Year Annualized FY 25
Apr-26	410	749	21		6.74	82.65	
May-26	155	410	10		3.14	82.64	
Jun-26	27	155	3		1.28	82.64	
Jul-26	0	27	1		0.85	82.63	
Aug-26	8	0	0		0.94	82.63	
Sep-26	68	8	1	FY 26	1.74	82.63	
Oct-26	309	68	7		4.99	82.63	
Nov-26	647	309	18		9.63	82.61	
Dec-26	895	647	29		13.13	82.59	
Jan-27	1,069	895	37		15.59	82.56	
Feb-27	881	1,069	37		13.18	82.53	
Mar-27	749	881	31		11.31	82.51	Future Test Year Annualized FY 26
Apr-27	410	749	22		6.72	82.49	
May-27	155	410	11		3.13	82.48	
Jun-27	27	155	3		1.28	82.48	
Jul-27	0	27	1		0.85	82.48	
Aug-27	8	0	0		0.94	82.48	
Sep-27	68	8	1	FY 27	1.74	82.47	
Oct-27	309	68	7		4.98	82.47	
Nov-27	647	309	19		9.61	82.45	
Dec-27	895	647	30		13.10	82.43	
Jan-28	1,069	895	38		15.56	82.40	
Feb-28	881	1,069	38		13.15	82.37	
Mar-28	749	881	32		11.29	82.35	Fully Projected Future Test Year Annualized FY 27

Combined Class RH incl. R, RT
UPC History 10/03-09/25

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.991615492
R Square	0.983301284
Adjusted R Square	0.983108607
Standard Error	0.751736623
Observations	264

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8651.836464	2883.945488	5103.353231	1.1372E-230
Residual	260	146.9280673	0.565107951		
Total	263	8798.764531			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.829781243	0.071312156	11.63590176	1.80393E-25	0.689358337	0.970204149	0.689358337	0.970204149
X Variable 1	0.001063503	0.000231826	4.58750188	6.98202E-06	0.000607007	0.001519999	0.000607007	0.001519999
X Variable 2	0.013799684	0.000228549	60.37949149	5.43E-155	0.013349641	0.014249727	0.013349641	0.014249727
X Variable 3	-0.025428251	0.01044362	-2.43481207	0.015572687	-0.045993096	-0.004863406	-0.045993096	-0.004863406

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm		ACT UPC CH Including N, NT, DS
Oct-12	335	309	110	335	Oct-12	26.21
Nov-12	785	647	335	785	Nov-12	57.01
Dec-12	853	895	785	853	Dec-12	75.83
Jan-13	1,047	1,069	853	1,047	Jan-13	93.30
Feb-13	974	881	1,047	974	Feb-13	87.11
Mar-13	884	749	974	884	Mar-13	72.43
Apr-13	427	410	884	427	Apr-13	38.41
May-13	178	155	427	178	May-13	18.32
Jun-13	21	27	178	21	Jun-13	13.14
Jul-13	4	0	21	4	Jul-13	11.04
Aug-13	12	8	4	12	Aug-13	12.87
Sep-13	143	68	12	143	Sep-13	15.81
Oct-13	327	309	143	327	Oct-13	25.28
Nov-13	773	647	327	773	Nov-13	57.86
Dec-13	1,012	895	773	1,012	Dec-13	89.26
Jan-14	1,310	1,069	1,012	1,310	Jan-14	118.75
Feb-14	1,114	881	1,310	1,114	Feb-14	100.59
Mar-14	976	749	1,114	976	Mar-14	85.10
Apr-14	467	410	976	467	Apr-14	38.16
May-14	152	155	467	152	May-14	18.49
Jun-14	14	27	152	14	Jun-14	11.96
Jul-14	10	0	14	10	Jul-14	13.10
Aug-14	13	8	10	13	Aug-14	12.61
Sep-14	98	68	13	98	Sep-14	18.39
Oct-14	303	309	98	303	Oct-14	23.07
Nov-14	759	647	303	759	Nov-14	58.80
Dec-14	909	895	759	909	Dec-14	85.81
Jan-15	1,231	1,069	909	1,231	Jan-15	111.51
Feb-15	1,275	881	1,231	1,275	Feb-15	115.14
Mar-15	960	749	1,275	960	Mar-15	88.83
Apr-15	403	410	960	403	Apr-15	35.19
May-15	83	155	403	83	May-15	15.10
Jun-15	32	27	83	32	Jun-15	14.54
Jul-15	4	0	32	4	Jul-15	12.44
Aug-15	6	8	4	6	Aug-15	15.21
Sep-15	42	68	6	42	Sep-15	14.39
Oct-15	378	309	42	378	Oct-15	26.46
Nov-15	508	647	378	508	Nov-15	43.85
Dec-15	625	895	508	625	Dec-15	54.85
Jan-16	1,130	1,069	625	1,130	Jan-16	98.39
Feb-16	936	881	1,130	936	Feb-16	89.07
Mar-16	582	749	936	582	Mar-16	50.16
Apr-16	468	410	582	468	Apr-16	35.34
May-16	221	155	468	221	May-16	20.36
Jun-16	25	27	221	25	Jun-16	14.67
Jul-16	2	0	25	2	Jul-16	11.51
Aug-16	3	8	2	3	Aug-16	15.49
Sep-16	53	68	3	53	Sep-16	13.54
Oct-16	324	309	53	324	Oct-16	24.12
Nov-16	589	647	324	589	Nov-16	46.56
Dec-16	973	895	589	973	Dec-16	85.94
Jan-17	961	1,069	973	961	Jan-17	93.94
Feb-17	719	881	961	719	Feb-17	67.48
Mar-17	879	749	719	879	Mar-17	74.42
Apr-17	264	410	879	264	Apr-17	30.86
May-17	205	155	264	205	May-17	21.24
Jun-17	33	27	205	33	Jun-17	12.53
Jul-17	2	0	33	2	Jul-17	14.22
Aug-17	19	8	2	19	Aug-17	13.53
Sep-17	89	68	19	89	Sep-17	13.96
Oct-17	227	309	89	227	Oct-17	22.62
Nov-17	684	647	227	684	Nov-17	60.38

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm		ACT UPC CH Including N, NT, DS
Dec-17	1,087	895	684	1,087	Dec-17	87.62
Jan-18	1,156	1,069	1,087	1,156	Jan-18	113.30
Feb-18	775	881	1,156	775	Feb-18	74.79
Mar-18	905	749	775	905	Mar-18	82.15
Apr-18	573	410	905	573	Apr-18	51.81
May-18	69	155	573	69	May-18	19.77
Jun-18	29	27	69	29	Jun-18	14.95
Jul-18	2	0	29	2	Jul-18	12.07
Aug-18	2	8	2	2	Aug-18	12.67
Sep-18	61	68	2	61	Sep-18	15.65
Oct-18	370	309	0	370	Oct-18	32.37
Nov-18	773	647	370	773	Nov-18	63.69
Dec-18	886	895	773	886	Dec-18	83.41
Jan-19	1,146	1,069	886	1,146	Jan-19	106.77
Feb-19	904	881	1,146	904	Feb-19	85.88
Mar-19	826	749	904	826	Mar-19	78.01
Apr-19	319	410	826	319	Apr-19	34.76
May-19	121	155	319	121	May-19	20.11
Jun-19	25	27	121	25	Jun-19	13.16
Jul-19	1	0	25	1	Jul-19	12.32
Aug-19	2	8	1	2	Aug-19	13.09
Sep-19	29	68	2	29	Sep-19	12.09
Oct-19	266	309	29	266	Oct-19	25.28
Nov-19	764	647	266	764	Nov-19	69.33
Dec-19	923	895	764	923	Dec-19	75.15
Jan-20	916	1,069	923	916	Jan-20	88.86
Feb-20	822	881	916	822	Feb-20	83.01
Mar-20	595	749	822	595	Mar-20	59.84
Apr-20	488	410	595	488	Apr-20	33.75
May-20	217	155	488	217	May-20	19.13
Jun-20	13	27	217	13	Jun-20	10.97
Jul-20	0	0	13	0	Jul-20	10.58
Aug-20	0	8	0	0	Aug-20	9.69
Sep-20	88	68	0	88	Sep-20	12.70
Oct-20	309	309	88	309	Oct-20	25.04
Nov-20	507	647	309	507	Nov-20	48.71
Dec-20	940	895	507	940	Dec-20	77.33
Jan-21	1025	1,069	940	1,025	Jan-21	95.24
Feb-21	969	881	1,025	969	Feb-21	88.31
Mar-21	649	749	969	649	Mar-21	62.72
Apr-21	388	410	649	388	Apr-21	36.33
May-21	204	155	388	204	May-21	21.12
Jun-21	12	27	204	12	Jun-21	12.14
Jul-21	0	0	12	0	Jul-21	12.25
Aug-21	0	8	0	0	Aug-21	12.45
Sep-21	53	68	0	53	Sep-21	13.02
Oct-21	183	309	53	183	Oct-21	20.97
Nov-21	720	647	183	720	Nov-21	59.92
Dec-21	759	895	720	759	Dec-21	70.60
Jan-22	1219	1,069	759	1,219	Jan-22	113.35
Feb-22	867	881	1,219	867	Feb-22	86.79
Mar-22	674	749	867	674	Mar-22	68.55
Apr-22	450	410	674	450	Apr-22	41.77
May-22	94	155	450	94	May-22	18.82
Jun-22	6	27	94	6	Jun-22	13.67
Jul-22	0	0	6	0	Jul-22	11.34
Aug-22	0	8	0	0	Aug-22	11.48
Sep-22	81	68	0	81	Sep-22	15.06
Oct-22	378	309	81	378	Oct-22	34.20
Nov-22	583	647	378	583	Nov-22	52.27
Dec-22	964	895	583	964	Dec-22	89.69
Jan-23	820	1,069	964	820	Jan-23	80.07

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm		ACT UPC CH Including N, NT, DS
Feb-23	748	881	820	748	Feb-23	78.61
Mar-23	734	749	748	734	Mar-23	70.28
Apr-23	311	410	734	311	Apr-23	31.64
May-23	164	155	311	164	May-23	22.36
Jun-23	21	27	164	21	Jun-23	14.22
Jul-23	0	0	21	0	Jul-23	12.57
Aug-23	1	8	0	1	Aug-23	14.30
Sep-23	71	68	1	71	Sep-23	15.47
Oct-23	289	309	71	289	Oct-23	26.19
Nov-23	678	647	289	678	Nov-23	62.59
Dec-23	756	895	678	756	Dec-23	73.24
Jan-24	985	1,069	756	985	Jan-24	97.26
Feb-24	815	881	985	815	Feb-24	78.38
Mar-24	603	749	815	603	Mar-24	59.18
Apr-24	341	410	603	341	Apr-24	36.56
May-24	95	155	341	95	May-24	18.48
Jun-24	4	27	95	4	Jun-24	14.23
Jul-24	0	0	4	0	Jul-24	14.35
Aug-24	12	8	0	12	Aug-24	14.38
Sep-24	35	68	12	35	Sep-24	12.78
Oct-24	278	309	35	278	Oct-24	24.95
Nov-24	562	647	278	562	Nov-24	48.68
Dec-24	957	895	562	957	Dec-24	91.08
Jan-25	1216	1,069	957	1,216	Jan-25	118.62
Feb-25	941	881	1,216	941	Feb-25	94.83
Mar-25	604	749	941	604	Mar-25	59.03
Apr-25	359	410	604	359	Apr-25	39.08
May-25	160	155	359	160	May-25	20.83
Jun-25	20	27	160	20	Jun-25	14.11
Jul-25	0	0	20	0	Jul-25	13.18
Aug-25	24	8	0	24	Aug-25	13.87
Sep-25	17	68	24	17	Sep-25	13.61
Oct-25		309	17	0		
Nov-25		647	0	0		
Dec-25		895	0	0		
Jan-26		1,069	0	0		
Feb-26		881	0	0		
Mar-26		749	0	0		
Apr-26		410	0	0		
May-26		155	0	0		
Jun-26		27	0	0		
Jul-26		0	0	0		
Aug-26		8	0	0		
Sep-26		68	0	0		
Oct-26		309	0	0		
Nov-26		647	0	0		
Dec-26		895	0	0		
Jan-27		1,069	0	0		
Feb-27		881	0	0		
Mar-27		749	0	0		
Apr-27		410	0	0		
May-27		155	0	0		
Jun-27		27	0	0		
Jul-27		0	0	0		
Aug-27		8	0	0		
Sep-27		68	0	0		
Oct-27		309	0	0		
Nov-27		647	0	0		
Dec-27		895	0	0		
Jan-28		1,069	0	0		
Feb-28		881	0	0		
Mar-28		749	0	0		

Regression Results:		
	8.3408035	Constant
	0.0062596	HDD-1
	0.0754111	HDD

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)		1 Month UPC	12 Months Ended UPC
Oct-12	309	68		32.07	32.07
Nov-12	647	309		59.07	91.13
Dec-12	895	647		79.88	171.02
Jan-13	1,069	895		94.56	265.58
Feb-13	881	1,069		81.47	347.05
Mar-13	749	881		70.34	417.38
Apr-13	410	749		43.95	461.33
May-13	155	410		22.60	483.93
Jun-13	27	155		11.35	495.27
Jul-13	0	27		8.51	503.78
Aug-13	8	0		8.94	512.73
Sep-13	68	8	FY 13	13.52	526.25
Oct-13	309	68		32.07	526.25
Nov-13	647	309		59.07	526.25
Dec-13	895	647		79.88	526.25
Jan-14	1,069	895		94.56	526.25
Feb-14	881	1,069		81.47	526.25
Mar-14	749	881		70.34	526.25
Apr-14	410	749		43.95	526.25
May-14	155	410		22.60	526.25
Jun-14	27	155		11.35	526.25
Jul-14	0	27		8.51	526.25
Aug-14	8	0		8.94	526.25
Sep-14	68	8	FY 14	13.52	526.25
Oct-14	309	68		32.07	526.25
Nov-14	647	309		59.07	526.25
Dec-14	895	647		79.88	526.25
Jan-15	1,069	895		94.56	526.25
Feb-15	881	1,069		81.47	526.25
Mar-15	749	881		70.34	526.25
Apr-15	410	749		43.95	526.25
May-15	155	410		22.60	526.25
Jun-15	27	155		11.35	526.25
Jul-15	0	27		8.51	526.25
Aug-15	8	0		8.94	526.25
Sep-15	68	8	FY 15	13.52	526.25
Oct-15	309	68		32.07	526.25
Nov-15	647	309		59.07	526.25
Dec-15	895	647		79.88	526.25
Jan-16	1,069	895		94.56	526.25
Feb-16	881	1,069		81.47	526.25
Mar-16	749	881		70.34	526.25
Apr-16	410	749		43.95	526.25
May-16	155	410		22.60	526.25
Jun-16	27	155		11.35	526.25
Jul-16	0	27		8.51	526.25
Aug-16	8	0		8.94	526.25
Sep-16	68	8	FY 16	13.52	526.25
Oct-16	309	68		32.07	526.25
Nov-16	647	309		59.07	526.25
Dec-16	895	647		79.88	526.25
Jan-17	1,069	895		94.56	526.25
Feb-17	881	1,069		81.47	526.25
Mar-17	749	881		70.34	526.25
Apr-17	410	749		43.95	526.25
May-17	155	410		22.60	526.25
Jun-17	27	155		11.35	526.25
Jul-17	0	27		8.51	526.25
Aug-17	8	0		8.94	526.25
Sep-17	68	8	FY 17	13.52	526.25
Oct-17	309	68		32.07	526.25
Nov-17	647	309		59.07	526.25
Dec-17	895	647		79.88	526.25
Jan-18	1,069	895		94.56	526.25

Regression Results:		
	8.3408035	Constant
	0.0062596	HDD-1
	0.0754111	HDD

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)		1 Month UPC	12 Months Ended UPC
Feb-18	881	1,069		81.47	526.25
Mar-18	749	881		70.34	526.25
Apr-18	410	749		43.95	526.25
May-18	155	410		22.60	526.25
Jun-18	27	155		11.35	526.25
Jul-18	0	27		8.51	526.25
Aug-18	8	0		8.94	526.25
Sep-18	68	8	FY 18	13.52	526.25
Oct-18	309	68		32.07	526.25
Nov-18	647	309		59.07	526.25
Dec-18	895	647		79.88	526.25
Jan-19	1,069	895		94.56	526.25
Feb-19	881	1,069		81.47	526.25
Mar-19	749	881		70.34	526.25
Apr-19	410	749		43.95	526.25
May-19	155	410		22.60	526.25
Jun-19	27	155		11.35	526.25
Jul-19	0	27		8.51	526.25
Aug-19	8	0		8.94	526.25
Sep-19	68	8	FY 19	13.52	526.25
Oct-19	309	68		32.07	526.25
Nov-19	647	309		59.07	526.25
Dec-19	895	647		79.88	526.25
Jan-20	1,069	895		94.56	526.25
Feb-20	881	1,069		81.47	526.25
Mar-20	749	881		70.34	526.25
Apr-20	410	749		43.95	526.25
May-20	155	410		22.60	526.25
Jun-20	27	155		11.35	526.25
Jul-20	0	27		8.51	526.25
Aug-20	8	0		8.94	526.25
Sep-20	68	8	FY 20	13.52	526.25
Oct-20	309	68		32.07	526.25
Nov-20	647	309		59.07	526.25
Dec-20	895	647		79.88	526.25
Jan-21	1,069	895		94.56	526.25
Feb-21	881	1,069		81.47	526.25
Mar-21	749	881		70.34	526.25
Apr-21	410	749		43.95	526.25
May-21	155	410		22.60	526.25
Jun-21	27	155		11.35	526.25
Jul-21	0	27		8.51	526.25
Aug-21	8	0		8.94	526.25
Sep-21	68	8	FY21	13.52	526.25
Oct-21	309	68		32.07	526.25
Nov-21	647	309		59.07	526.25
Dec-21	895	647		79.88	526.25
Jan-22	1,069	895		94.56	526.25
Feb-22	881	1,069		81.47	526.25
Mar-22	749	881		70.34	526.25
Apr-22	410	749		43.95	526.25
May-22	155	410		22.60	526.25
Jun-22	27	155		11.35	526.25
Jul-22	0	27		8.51	526.25
Aug-22	8	0		8.94	526.25
Sep-22	68	8	FY22	13.52	526.25
Oct-22	309	68		32.07	526.25
Nov-22	647	309		59.07	526.25
Dec-22	895	647		79.88	526.25
Jan-23	1,069	895		94.56	526.25
Feb-23	881	1,069		81.47	526.25
Mar-23	749	881		70.34	526.25
Apr-23	410	749		43.95	526.25
May-23	155	410		22.60	526.25

Regression Results:		
	8.3408035	Constant
	0.0062596	HDD-1
	0.0754111	HDD

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)		1 Month UPC	12 Months Ended UPC	
Jun-23	27	155		11.35	526.25	
Jul-23	0	27		8.51	526.25	
Aug-23	8	0		8.94	526.25	
Sep-23	68	8	FY23	13.52	526.25	
Oct-23	309	68		32.07	526.25	
Nov-23	647	309		59.07	526.25	
Dec-23	895	647		79.88	526.25	
Jan-24	1,069	895		94.56	526.25	
Feb-24	881	1,069		81.47	526.25	
Mar-24	749	881		70.34	526.25	
Apr-24	410	749		43.95	526.25	
May-24	155	410		22.60	526.25	
Jun-24	27	155		11.35	526.25	
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Oct-24	309	68		32.07	526.25	
Nov-24	647	309		59.07	526.25	
Dec-24	895	647		79.88	526.25	
Jan-25	1,069	895		94.56	526.25	
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Oct-25	309	68		32.07	526.25	
Nov-25	647	309		59.07	526.25	
Dec-25	895	647		79.88	526.25	
Jan-26	1,069	895		94.56	526.25	
Feb-26	881	1,069		81.47	526.25	
Mar-26	749	881		70.34	526.25	Historic Test Year Annualized FY 25
Apr-26	410	749		43.95	526.25	
May-26	155	410		22.60	526.25	
Jun-26	27	155		11.35	526.25	
Jul-26	0	27		8.51	526.25	
Aug-26	8	0		8.94	526.25	
Sep-26	68	8	FY26	13.52	526.25	
Oct-26	309	68		32.07	526.25	
Nov-26	647	309		59.07	526.25	
Dec-26	895	647		79.88	526.25	
Jan-27	1,069	895		94.56	526.25	
Feb-27	881	1,069		81.47	526.25	
Mar-27	749	881		70.34	526.25	Future Test Year Annualized FY 26
Apr-27	410	749		43.95	526.25	
May-27	155	410		22.60	526.25	
Jun-27	27	155		11.35	526.25	
Jul-27	0	27		8.51	526.25	
Aug-27	8	0		8.94	526.25	
Sep-27	68	8	FY27	13.52	526.25	
Oct-27	309	68		32.07	526.25	
Nov-27	647	309		59.07	526.25	
Dec-27	895	647		79.88	526.25	
Jan-28	1,069	895		94.56	526.25	
Feb-28	881	1,069		81.47	526.25	
Mar-28	749	881		70.34	526.25	Fully Projected Future Test Year Annualized FY 27

Combined Class CH Incl N, NT and DS
UPC History 10/12-09/25

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.987490708
R Square	0.975137898
Adjusted R Square	0.974812903
Standard Error	5.176552179
Observations	156

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	160805.4659	80402.73297	3000.472282	1.814E-123
Residual	153	4099.893946	26.79669246		
Total	155	164905.3599			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.340803454	0.634619101	13.14300727	6.89559E-27	7.087056105	9.594550804	7.087056105	9.594550804
X Variable 1	0.0062596	0.001803054	3.471665865	0.000672524	0.002697505	0.009821696	0.002697505	0.009821696
X Variable 2	0.075411094	0.001802329	41.84091388	1.16709E-85	0.07185043	0.078971757	0.07185043	0.078971757

SDR-RR-12

Request:

In the form identical to the previous question, please provide a database for all independent variables which were analyzed by the Company, but exclude from the filed gas demand models.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-13

Request:

For each customer receiving service at less than the maximum applicable tariff rate, please provide:

a. actual consumption for the two most recent calendar years;

b. actual consumption for the HTY and the most recent twelve month period for which data is available;

c. the currently applicable rate;

d. an explanation for the rate discount.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-14

Request:

Please provide a copy of the Company's detailed capital budgets for the preceding and current calendar years which underlie the projected test year capital additions in this case.

Response:

Please see the response to SDR-ROR-14.

Prepared by or under the supervision of: Vicky A. Schappell

SDR-RR-15

Request:

Please provide a variance or other similar report comparing actual and budgeted construction expenditures at the conclusion of each budget period for the past three years and as of the most recent date available.

Response:

Please see Attachment SDR-RR-15 for a three-year comparison of the actual and budgeted plant in service additions.

Prepared by or under the supervision of: Vicky A. Schappell

UGI UTILITIES, INC. – GAS DIVISION
CAPITAL PLANT ADDITIONS – BUDGET VS. ACTUAL
FOR THE YEARS ENDED SEPTEMBER 30, 2023 THROUGH SEPTEMBER 30, 2025
(thousands of dollars)

	09/30/2023	09/30/2024	09/30/2025
Budgeted Plant Additions	$ 495,003	$ 381,462	$ 419,491
Actual Plant Additions	496,372	376,346	408,122
Variance	$ 1,369	$ (5,116)	$ (11,369)

SDR-RR-16

Request:

Please provide a breakdown of other gas revenue for the three preceding calendar years.

Response:

Please see Attachment SDR-RR-16. The other operating revenue is shown net of the Company's share of off-system sales, capacity releases, choice supplier fees and company share of RINs.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
OTHER GAS REVENUES
FOR THE YEARS ENDED SEPTEMBER 30, 2023, 2024, 2025

(000)'s

Account No.		9/30/2023	9/30/2024	9/30/2025
495001	Miscellaneous Gas Revenues	639	848	1,067
495002	Interest on Deferred Fuel Over/Under Collection	(207)	3,179	(448)
495003	Interest on Supplier Refund	598	1,091	247
495004	POR Administrative Fees	109	103	115
		$ 1,139	$ 5,220	$ 980

SDR-RR-17

Request:

For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present:

a. depreciable utility plant in service
b. non-depreciable utility plan in service
c. construction work in progress
d. accumulated deferred income tax
e. materials and supplies
f. customer advances for construction
g. contributions in aid of construction
h. accumulated depreciation
i. prepayments by type
j. customer deposits
k. injury and damages reserve

Response:

Please refer to Attachment SDR-RR-17 for the requested information.

Prepared by or under the supervision of: Amy M. Keller

UGI UTILITIES, INC. - GAS DIVISION
Actual Ending Balances *(in Thousands)*
For the Months Ended October 31, 2024 through October 31, 2025

Account Description	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025
a) Depreciable Plant	5,440,421	5,464,581	5,481,074	5,492,739	5,509,202	5,528,885	5,551,650	5,575,009	5,610,900	5,653,639	5,691,921	5,783,345	5,811,977
b) Non-Depreciable Plant	23,757	23,757	23,757	23,806	23,777	23,777	23,777	23,777	23,777	23,777	23,777	23,777	23,777
c) Construction Work in Progress	72,665	74,510	79,191	83,257	87,909	98,837	108,242	116,164	123,824	126,336	137,539	99,469	106,020
d) Accumulated Deferred Income Tax	1,037,236	1,038,952	1,042,666	1,044,033	1,045,400	1,037,476	1,038,843	1,040,209	1,045,076	1,046,443	1,047,810	1,064,859	1,067,810
e) Materials and Supplies	30,051	29,656	30,027	29,859	30,404	29,680	29,066	28,793	27,817	26,703	25,565	24,737	24,028
f) Customer Advances	-	-	-	-	-	-	-	-	-	-	-	-	-
g) Contributions in Aid of Construction	**Not applicable, as capital expenditures are shown net of any anticipated amounts for CIAC.**												
h) Accumulated Depreciation	(1,462,296)	(1,470,034)	(1,480,835)	(1,486,972)	(1,494,597)	(1,503,108)	(1,510,480)	(1,518,454)	(1,528,002)	(1,536,536)	(1,544,135)	(1,551,209)	(1,552,499)
i) Prepayment by Type													
Prepaid Taxes	608	516	431	345	365	559	466	380	285	749	842	751	652
PUC Annual Assessment	3,033	2,654	2,275	1,896	1,517	1,137	758	379	(0)	(0)	(0)	3,413	3,034
Prepaid IT Services	8,174	7,746	9,504	9,569	8,551	8,108	7,004	6,315	6,445	7,996	7,253	6,804	6,881
Miscellaneous	12,343	11,849	10,866	10,469	9,736	8,832	11,934	9,787	6,304	5,174	11,118	8,342	7,459
j) Gas Customer Deposits	21,060	21,377	21,649	22,118	22,876	24,012	24,724	24,809	24,696	24,599	24,530	24,483	24,714
k) Injury and Damage Reserve	2,349	2,223	2,256	2,207	2,160	2,078	2,072	2,041	1,515	1,390	1,380	2,103	1,927

SDR-RR-18

Request:

Please provide a copy of all work papers supporting the Company's lead/lag study.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4, and the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-19

Request:

Please provide the payroll distribution showing the percentage of wages charged to O&M and other categories for each of the preceding three calendar years and the most recent annual period available.

Response:

Please see Attachment SDR-RR-19.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Annual Payroll Data
For the Years Ended September 30, 2023 through 2025
(thousands of dollars)

	12 Months Ended 9/30/2023	9/30/2024	9/30/2025
Operations and Maintenance	$ 70,177	$ 74,056	$ 73,218
Capital	54,606	54,618	52,900
Other Non-Expense	8,581	4,421	9,702
Total	$ 133,364	$ 133,095	$ 135,820
Percentage Charged to O&M	52.7%	55.7%	54.0%
Percentage Charged to Capital	40.9%	41.0%	38.9%
Percentage Charged to Other Non-Expense	6.4%	3.3%	7.1%

SDR-RR-20

Request:

Please state whether the future test year budgeted labor includes any increases or decreases in the number of employees during the future test year. If increases have been budgeted, please state whether the future test year includes budgeted positions which have not been filled.

Response:

During the historic test year ("HTY"), UGI Gas completed a review of labor to determine the required base positions needed for the ongoing operations of the business, as well as additional positions needed in the future. The future test year ("FTY") budgeted labor as of September 30, 2026 includes additions of 11 Gas Operations positions, 5 IT positions, 4 Customer Service positions, 2 Supply positions, and 1 Accounting position.

The fully projected future test year ("FPFTY") labor budget as of September 30, 2027 includes no additional gas operations positions beyond those added in the FTY.

As of October 27, 2025, filled positions include: 4 Gas Operations positions, 1 Customer Service position, 1 Supply position and 1 Accounting position. The additional positions are expected to be filled throughout the course of Fiscal 2026, and before September 30, 2026.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-21

Request:

Please explain how the Company has treated routine or normal position vacancies which occur as a result of terminations or retirements in its budgeted labor projections.

Response:

During the budgeting process, currently open positions are reviewed to determine if they should be excluded or carried forward into the upcoming budget year. In addition to reviewing individual open positions, vacancy rates are also reviewed across the various functional groups throughout the organization. An appropriate overall vacancy rate is then built into the labor budget, thereby reducing total budgeted headcounts and associated expenses to take these vacancies into account. Vacancy rates are reflected in both the Future Test Year (FTY) and the Fully Projected Future Test Year (FPFTY) labor projections.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-22

Request:

Please provide the most recent insurance premiums for each type of insurance coverage (i.e., employee benefit and those purchased by the Company) reflected in the Company's filing. If available, please provide estimated premiums for the subsequent calendar year.

Response:

Please see Attachment SDR-RR-22.1 for insurance premiums paid and expected.

Please see Attachment SDR-RR-22.2 for employee medical and related benefit costs paid and expected.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
Insurance Premiums Paid & Expected Premiums
For the 12 Months Ending September 30,

	2025		2026	
	Gross Expense	**Net Expense**	**Gross Expense**	**Net Expense**
Excess Liability*	$ 9,505,279	$ 6,372,412	$ 10,585,018	$ 7,057,534
Property	391,894	329,075	385,511	385,511
Workers' Compensation*	386,123	210,746	299,634	170,791
Cyber	545,497	545,497	517,837	517,837
Other	-	-	786	786
Fiduciary	120,268	65,754	123,866	123,866
Employment Practices	77,751	51,775	82,203	82,203
Bond	72,497	72,497	106,932	106,932
Total Insurance	**$ 11,099,308**	**$ 7,647,755**	**$ 12,101,786**	**$ 8,445,459**

*Any costs below the Company's self insurance retention are not reflected in the above premiums.

UGI UTILITIES, INC. - GAS DIVISION
Employee Medical and Related Benefit Costs Paid & Expected
For the 12 Months Ending September 30,

	2025		2026	
	Gross Expense	**Net Expense**	**Gross Expense**	**Net Expense**
Medical*	15,794,247	9,017,931	17,171,050	9,358,222
Dental	352,723	201,392	400,892	218,486
ADD & Life Insurance Benefits	108,423	108,423	119,941	119,941
Short-Term Disability	48,644	48,644	64,333	64,333
Long-Term Disability	373,662	373,662	445,957	445,957
Total Benefits	**$ 16,677,700**	**$ 9,750,053**	**$ 18,202,175**	**$ 10,206,941**

*These costs include claims, premiums paid for stop loss coverage and company paid Health Savings Account contributions.

SDR-RR-23

Request:

Please provide a copy of the Company's two most recent FERC Form 2.

Response:

UGI Utilities, Inc. - Gas Division is not required to file and has not filed a FERC Form 2.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-24

Request:

Please provide a description of each employee benefit program or plan.

Response:

Please see Attachment SDR-RR-24.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc – Gas Division

Benefit Program Effective January 1, 2026

Employee Medical Plan

All employees and their dependents have the option to participate in a health care program that provides three options: an Independence Blue Cross Preferred Provider Option Plan, an Independence Blue Cross Preferred Provider Basic Plan, and an Independence Blue Cross High Deductible Plan with a Health Savings Account. Employees who elect medical coverage receive the Prescription Drug coverage at no additional cost. Employees share in the cost of medical plans.

A brief summary of each is listed below:

	IBX PPO Preferred	IBX PPO Basic	IBX HDHP
Annual Deductible	$600 Individual $1,500 Family	$1,500 Individual $3,750 Family	$2,500 Individual $3,400 employee and Spouse or Employee and Child(ren) $5,000 Family
Coinsurance after deductible	15%	30%	10%
UGI HSA Annual Funding	N/A	N/A	$1,000 Individual $2,000 Family
Out of Pocket Maximum	$3,500 Individual $8,750 Family	$4,500 individual $9,000 family	$4,000 Individual $8,000 Family
Office Visit / Specialist (incl Telehealth) Copay	$25 / $40	$30 / $40	10% after deductible
Pharmacy Deductible (through CVS)	$150 Individual $350 Family	$150 Individual $350 Family	Subject to medical deductible

A summary of prescription copays is below:

	30-Day Supply at Participating Pharmacy	90-Day Supply at CVS	Mail Order 90-Day Supply
Generic	$10 copay	$20 copay	$20 copay
Brand Name Formulary	$20 copay	$40 copay	$40 copay
Brand Name Non-Formulary	$35 copay	$70 copay	$70 copay

CVS – Weight Management Program

UGl offers a Weight Management program through CVS to support members on their weight loss journey. Members enrolled in a UGI medical plan may now be eligible for the weight loss management program upon meeting specific criteria. Members who are on a GLP1 medication are required to participate in this program.

Dental Plan

All employees have access to the following dental plans:

Benefit – In network	Basic Dental	Buy Up Dental
Annual Deductible:	$50 Individual/$150 Family	No deductible
Diagnostic and Preventive, to include cleanings, fluoride treatments, sealants, x- rays	100%; no deductible	100%; no deductible
Basic Restorative, oral surgery, endodontics	50% after deductible	90% after deductible
Major Restorative, Prosthodontics	50% after deductible	60% after deductible
Repairs of crowns, inlays, onlays, bridges, dentures, endodontics, general anesthesia, and periodontal	50% after deductible	90% after deductible
Annual Maximum for covered services	$1,000	$2,500
Orthodontics	50% with $1,000 lifetime per individual	60% with $2,500 lifetime per individual

The employee only premium for the Basic Dental coverage is paid for by UGI.
UGI's contribution for the Buy-Up plan is slightly higher than the cost for the Basic Plan.

Vision Plans

All employees have access to the following vision plans:

Benefit	Vision Base	Vision Buy Up
Exam for glasses	100%	100%
Clear Standard/Single Vision/Bifocal/Blended Bifocal/Trifocal	$20 copay	$20 copay
Custom Progressive Lenses	$150 - $175	$150 - $175
Standard Progressive Lenses	100%	100%
Elective contact lenses in lieu of glasses	Up to $140	Up to $150

Both Vision plans are 100% employee paid.

Flexible Spending Accounts

All employees are eligible to participate in Health Care or Dependent Day Care Spending Accounts. The annual maximum election for a Health Care Account is $3,300 and the minimum is $104. The annual maximum election for the Dependent Day Care is $7,500 ($3,750 if married and filing separate tax returns) and the minimum is $104. Employees who enroll in the Blue Cross High Deductible Health Plan are eligible for a Limited Purpose Heath Care spending account per IRS regulations.

Group Life Insurance

All employees receive company paid basic life in the amount of one times their annual salary (including certain bonuses) rounded to the next highest $1,000. Part-time employees receive $10,000.

Employees may elect additional employee voluntary life insurance of 1, 2, 3, 4, or 5 times annual salary rounded to the nearest $1,000. This coverage is 100% employee paid. Employee may also elect voluntary life insurance for a spouse in amounts from $10,000 to $100,000 in increments of $10,000. Child(ren) life insurance is also available in the amount of $10,000, Both spouse and child(ren) life insurance are 100% employee paid.

Accidental Death & Dismemberment (AD&D) and Business Travel Accident (BTA) Insurance

All employees are covered under AD&D insurance 24 hours per day, 365 days per year. The maximum benefit is one times annual salary to a maximum of $2 million. Employee may elect voluntary AD&D at 1, 2, 3, 4, or 5 times salary to a maximum of $2 million. Spouse only equals 50% of employee coverage. Child(ren, only equals 15% of employee coverage; Spouse and Child(ren) equals 40% for Spouse and 10% for Child(ren) of employee coverage.

All voluntary AD&D coverage is paid 100% by employees.

All employees are covered by Business Travel Accident with a maximum benefit of 4 times annual salary to a maximum of $2 million.

Teladoc

Telemedicine available 7 days a week, 24 hours a day from a mobile device or computer. Any needed prescriptions are sent to the pharmacy of your choice. Medical and mental health services are available for no copay for those enrolled in one of the PPO plans and nominal copays for those employees who have elected HDHP plan. Must be enrolled in one of UGI medical plans.

- **Diabetes and Hypertension Management** – Both are covered through Teledoc at no additional cost to the employee if enrolled in one of UGI medical plans.

Sleep and Anxiety Program

At no additional cost to the employee if they are enrolled in one of UGI medical plans, employees have access to tools to help them manage their sleep and anxiety.

Musculoskeletal Care Digital Physical Therapy – Sword Thrive

At no additional cost to the employee if they are enrolled in one of UGI medical plans, employees have access to tools to help them manage physical therapy to support their musculoskeletal health.

Additional Voluntary Benefits – Employee paid:

- **Critical Illness** provides a lump sum payment upon diagnosis of Cancer, Heart Attack, Stroke or Major Organ Transplant. Coverage available: Employee $5,000, $10,000 or $20,000; Spouse $5,000, $10,000 or $20,000; Children $5,000 or $10,000.
- **Hospital Indemnity** provides a daily benefit for a covered stay, in a hospital, critical care unit, or rehabilitation facility which can be used to help pay for expenses not paid for my medical plan, lost wages, childcare, travel, or other regular household expenses. This is a fixed indemnity policy, not health insurance.
- **Accident Insurance** provides cash for covered injuries that occur on and off the job. Benefits include emergency room visits, fractures and dislocation, ambulance transportation, intensive care, surgeries, and more.
- **Identify Theft Protection** provides two different levels of coverage: credit monitoring/digital footprint/locking TransUnion credit or $2M in ransomware expense reimbursement/active threat detection, and safety VPN.
- **Pet Insurance** coverage will reimburse eligible veterinary expenses relating to accidents, illnesses, and injuries for pets, like dogs and cats. There are two levels of coverage, one provides pets with wellness coverage.
- **Whole Life Insurance with Long-Term Care** provides whole life insurance that an employee can purchase now and take with them when they leave the company at the same rate, as long as they continue to pay. Also provides employees a way to build cash value at a guaranteed rate to be used later in life for long-term care.

Short Term Disability

The Company provides a self-insured pay continuation illness plan for all employees. The percentage of pay continued and the number of weeks at 100% and 50% are based on years of service. Short term disability is available for a maximum of 6 months of disability.

Long Term Disability

Employees who exhaust short term disability benefits are eligible to apply for long term disability which is an insured program. Employees who qualify receive 60% of base monthly income offset by other disability income such as Social Security. Maximum benefit is $20,000 per month. Minimum benefit is the greater of $100 or 10% of the gross disability payment per month.

Savings Plan – 401(k)

All employees are eligible to participate in the deferred savings plan which is a tax qualified 401(k) program. The Plan offers pre-tax, after-tax and Roth contributions up to the IRS limit. For 2026 the total contribution for pre-tax, after-tax, Roth and company match is $69,000. If over 50 years of age, the catch-up contribution is $7,500 for a total maximum contribution of $76,500. The Company match is before, after or on Roth contributions at 50% of the first 3% and 25% of the next 3% of salary deferred for those employees who participate in the defined benefit pension plan. Participants are immediately vested in the Company match.

Employees hired on or after January 1, 2009 are eligible for an enhanced company match of 100% of 6% effective January 1, 2019 because they are not eligible for the defined benefit pension plan. Vesting is immediate.

401k ROTH Catch-up IRS Secure 2.0 Change

The IRS has added a new ruling under the SECURE 2.0 Act for employees who are over 50 and would like to elect a catch-up contribution. If you earned $145,000+ in the prior year (2025 wages for 2026 contributions), and would like to elect the catch-up, it must be elected as a Roth catch-up, not pre-tax.

Educational Assistance

Full-time employees with a summary performance rating of "Met Objectives" or higher on their most recent annual review may be eligible to participate in the Company's tuition reimbursement program for courses offered by approved educational institutions. To be eligible for reimbursement studies selected must be related to some phase of the employee's current job, or be a direct benefit to the Company's operation, or be part of a required course for a degree (associates, bachelors or masters) or certificate related to the Company's operation. PhD programs are excluded.

The Company will reimburse 80% of tuition costs only, excluding the cost of books, supplies and other associated fees at qualified educational institutions. The maximum reimbursement per calendar year is limited to $6,300 for undergraduate courses and $10,000 for graduate level courses. In order to receive reimbursement, the employee must provide evidence of satisfactory completion of the course. For courses with letter grades, "satisfactory completion" is defined as follows:

- a grade of "C" or better for undergraduate classes
- a grade of "B" or better for graduate level classes

UGI financially supports employees to retain certification and/or licensure that is required in their current role; or, to obtain certification/licensure which will increase their knowledge and skills as it relates to their current work responsibilities. Oftentimes a course provides valuable assistance in preparing for a certification/licensure exam. This policy enables financial support for reimbursement of approved courses that prepare those who will take an exam to have a greater opportunity for success. This policy also provides financial support for the renewal/maintenance fees for job-related certification/licensure.

This policy applies to all full-time employees and part-time employees 20 hours or more weekly, with "Met Objectives" or higher on their most recent annual review. For employees who have not yet received formal reviews, supervisor approval of application signifies confirmation of "Met Objectives" to date. The professional certification/licensure must be considered by the Company to be directly related to the employee's current job and must be of direct benefit to the Company's operation unless approved by the departmental Vice President and Human Resources.

Paid Time Off

The Company provides all employees with 10 paid holidays and 3 personal days per calendar year. Employees are provided vacation allowances based on years of service ranging from 3 weeks during the first calendar year of employment on a prorated basis up to 6 weeks after 35 years of service.

Severance Program

Exempt employees, in levels M2 – M6 and P3 – P5 are eligible for a severance allowance of two weeks of compensation for each year of service with a minimum of two months of compensation and a maximum of 12 months of compensation. Severed employees will also receive a lump sum payment equal to the COBRA cost of continued medical and dental coverage for the period of severance less the active employee contribution amount.

Exempt employees, in levels M1, P1 - P2 and non-bargaining non-exempt employees, are eligible for a severance allowance of one week of compensation for each year of service with a minimum of two weeks of compensation and a maximum of 12 months of compensation.
Severed employees will also receive a lump sum payment equal to the COBRA cost of continued medical and dental coverage for the period of severance less the active employee contribution amount.

Post-Retirement Benefits

Retirement Plan – UGI Utilities, Inc. Employees Hired Prior to 1/1/2009

The Plan is a noncontributory defined benefit plan covering substantially all employees of UGI Utilities, Inc. hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date.

Substantially all employees of the UGI Employers hired prior to January 1, 2009 who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, while in the employ of the UGI Employers, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be the greatest of:

- 1.9% of final average earnings, as defined, times years of credited service, as defined, (which amount cannot exceed 60% of the average monthly earnings for the highest consecutive 12-month period during the 120 consecutive month period prior to the date of retirement or termination), less (b) 1% of the primary Social Security benefit, as defined, times the years of credited service at age 65 (maximum of 35 years) and in the case of early retirement, multiplied further by the ratio of actual credited service to projected credited service at normal retirement date; or
- 25% of earnings during the last 12 months prior to retirement multiplied by the ratio (not to exceed 1.0) of years of projected credited service to normal retirement date to 15, and in the case of early retirement, multiplied further by the ratio (not to exceed 1.0) of years of credited service earned to the projected years of credited service at normal retirement date.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of ten years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 62 to age 65, who have completed 10 years of vesting service.

Retirement Plan – UGI Utilities, Inc. Employees That Are Former Non-Union Employees of UGI Central Penn Gas, Inc. Hired Prior to 1/1/2009 or Former Union Employees of UGI Central Penn Gas, Inc. Hired Prior to 1/1/2012

The Plan is a non-contributory defined benefit plan covering employees of UGI Central Penn Gas, Inc. hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date except for employees subject to a collective bargaining agreement. The plan closed for those employees on January 1, 2012.

Substantially all CPG employees of the UGI Employers hired prior to January 1, 2009, or January 1, 2012 for those covered under a collective bargaining unit, who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, while in the employ of the UGI Employers, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be:

- 1.08% of average monthly earnings up to covered monthly earnings times years of credited service up to 35 years

Plus

- 1.35% of average monthly earnings that are more than the covered monthly earnings times years of credited service up to 35 years

There is a group of CPG employees whose pension benefits are calculated under a grandfathered pension formula. Their annual pension benefits shall generally be:

- 1.65% of the first $833.34 of monthly earnings, plus 2% of monthly earnings in excess of $833.34 for each year of credited service.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of ten years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 60 to age 65, who have completed 10 years of vesting service.

Retirement Plan – UGI Utilities, Inc. Employees That Are Former Employees of UGI Penn Natural Gas, Inc. Hired Prior to 1/1/2009

The Plan is a noncontributory defined benefit plan covering substantially all employees hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date.

Substantially all employees hired prior to January 1, 2009 who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be:

A. (1.25% of Final Average Earnings up to the Base Amount) times (your years of Credited Service up to 30 years)

Plus

B. (1.65% of Final Average Earnings over the Base Amount) times (your years of Credited Service up to 30 years)

In no event will the benefit be less than the ratio of years of Credited Service (maximum of 30) divided by 30 and multiplied by $1,800.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of 10 years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 62 to age 65, who have completed 10 years of vesting service.

Retiree Subsidy Medical Program – UGI Utilities, Inc. Employees

An eligible employee is any full-time employee of UGI Utilities, Inc. Who, as of January 1, 1989, was at least 55 years of age and had completed at least 10 years of service with UGI or an affiliated corporation or whose age and years of service equaled at least 80 and who immediately following his retirement from UGI commences receipt of an early, normal or late retirement pension.

Effective January 1, 2014, retiree medical for Medicare-eligible retirees (age 65 or over) was outsourced to a third party and the benefit was changed to a health reimbursement account. In addition, the Retiree Plan covers Medicare-eligible disabled employees who are receiving long term disability benefits. Retirees and spouses who retired on or after 1/1/1986 receive $500 per calendar year and those who retired prior to 1/1/1986 receive $700 per calendar year. (Retirees and spouses is a closed group)

Retiree Medical Insurance –UGI Utilities, Inc. Employees Previously Employed by UGI Central Penn Gas, Inc.

Any employees who previously retired from the employment of UGI Central Penn Gas, Inc. (or a predecessor employer ("CPG") before the October 1, 2008 acquisition of CPG by UGI, an Eligible Retired Employee shall mean: any retired employee who was at least 55 years of age, had completed at least 10 years of service with CPG, had retired and commenced receipt of his retirement pension under the PPL Gas Retirement Plan immediately following his retirement from CPG and was receiving benefits under the PPL Gas Retiree Medical Plan as of October 1, 2008.

Any full-time employees of CPG who retired from the employment of CPG on or after the October 1, 2008 acquisition of CPG by UGI, an Eligible Retired Employee shall mean: any full- time employee of CPG who is at least 55 years of age, has completed at least 10 years of service with CPG, retires and commences receipt of his retirement pension under the PPL Gas Retirement Plan immediately following his retirement from CPG and retired from CPG on or after the October 1, 2008 acquisition of CPG by the Company, but on or before January 1, 2009;

Any full-time employee who was covered under the terms of a collective bargaining agreement between a collective bargaining representative and CPG and who is at least 55 years of age, has completed 10 years of service with CPG and retired prior to January 1, 2012.

Retiree Life Insurance

Pension-eligible employees who retire are eligible for retiree life insurance in the amount of 25% of their pre-retirement amount with a maximum coverage amount of $50,000. There is no cost to the retiree.

SDR-RR-25

Request:

Please provide a description of the Company's merit and cost of living wage rate increase policies.

Response:

The Company does not provide wage adjustments based on the changes in the cost of living index.

Non-Union Employees:

The Company maintains a salary structure which is comprised of salary grades and ranges. All non-union positions are assigned a salary range based on the competitive value of the job. The salary structure is reviewed periodically and adjusted, at the discretion of management, to remain externally competitive and internally equitable in order to attract, motivate, and retain quality employees.

Funds are budgeted for merit increases based on prevailing market rates. Performance reviews are scheduled annually with employees. Merit increase guidelines are established, and individual performance ratings determine individual merit increases. Please see Attachment SDR-RR-25 for a summary of merit guidance provided to UGI Utilities, Inc. People Leaders for the Fiscal 2026 merit process.

Union Employees:

Employees who are represented by bargaining units are paid according to the rates negotiated in their labor agreements.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. – GAS DIVISION
Merit and Cost of Living Wage Rate Increase
For 2026 Plan Year

This document provides a summary of the FY26 Salary Planning Memo provided to People Leaders:

Salary Planning Guidelines:

Managers are required to stay within their respective merit budgets. Any request to exceed the budget require next-level Manager and HR Business Partner confirmation and verification of available funding within the function.

Merit Eligibility:

All Regular full-time (FT) and part-time (PT) employees in an Active status are eligible for merit review. The following groups are excluded from merit review:

- Employees hired on or after July 1
- Union Employees

Merit Guidelines:

Annual Salary Planning is the time to reward employees based on the outcome of their performance review. Managers will be provided with "Merit Guidelines" based on the approved merit budget, the employee's performance rating, and current salary position in range (Merit Matrix).

- Merit Matrix recommended range details will be shown for each employee but will not pre-populate a merit increase recommendation by person. Managers are required to populate this field for each employee,
- Merit increases for employees hired after the start of the prior fiscal year are prorated based on hire date.
- Managers have discretion to recommend a deviation from guidelines while remaining within overall budget

FY26 Merit Matrix (for FY25 Performance Year)

• Performance Ratings	Lower Third	Middle Third	Upper Third	Above Maximum
Exceeded Objectives	4.2% - 6.2%	3.7% -5.7%	3.2% - 5.2%	2.7% - 4.7%
Exceeded Some Objectives	3.2% - 5.2%	2.7% - 4.7%	2.2% - 4.2%	1.2% - 3.2%
Met Objectives	2.2% - 4.2%	1.7% - 3.7%	1.2% - 3.2%	0.0% - 2.2%
Met Some Objectives	1.0% - 2.0%	1.0% - 2.0%	0.0%	0.0%
Did Not Meet Objectives	0.0%	0.0%	0.0%	0.0%

Additional Pay Guidelines:

- At or Above Max: Employee with current salary at or above pay range max may receive an above max one-time merit payment in lieu of a base pay merit increase for this fiscal year
- Non-Merit Salary Adjustments: On-cycle non-merit salary adjustments (e.g., promotions, market adjustments, etc.) are permitted to be processed throughout the merit cycle with effective dates other than October 1; all merit and non-merit records are subsequently reconciled
- Terminations: If, prior to completion of the annual salary planning process, an employee gives notice of an intent to separate from the Company, guidance is not to award a merit increase

SDR-RR-26

Request:

Please provide the following monthly labor data for the year prior to the HTY, the HTY and the FTY through the most recent date available.

a. number of actual employees broken down between type (e.g., salaried, union, non-union, temporary, etc.);

b. regular payroll broken down between expensed, capitalized and other;

c. overtime payroll broken down between expensed, capitalized and other;

d. temporary payroll broken down between expensed, capitalized and other; and

e. other payroll (specify).

Response:

a. Please see Attachment SDR-RR-26, page 1. Headcount is provided on a full time equivalent (FTE) basis. Consistent with the method of payroll cost allocation, shared service employees who provide services to both UGI Gas and UGI Electric are counted as 90%, 88%, and 89% of an FTE within this analysis for the year prior to the HTY, HTY, and FTY respectively.

b. & c. Please see Attachment SDR-RR-26, page 2.

d. Not available.

e. Not applicable.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
EMPLOYEE COUNT

12 MONTHS ENDED SEPTEMBER 30, 2024

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	677	679	685	683	682	682	674	674	668	672	665	661
Non-Union	903	896	889	888	885	876	873	864	852	849	846	843
Non-Union Temporary	7	4	2	1	1	1	1	1	1	1	1	1
Total	1,587	1,579	1,576	1,572	1,568	1,559	1,548	1,539	1,521	1,522	1,512	1,505

12 MONTHS ENDED SEPTEMBER 30, 2025

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	662	663	662	664	663	663	664	666	673	682	685	689
Non-Union	843	838	835	837	834	833	840	846	839	833	838	842
Non-Union Temporary	1	-	-	-	-	-	-	9	11	11	2	2
Total	1,506	1,501	1,497	1,501	1,497	1,496	1,504	1,520	1,523	1,526	1,525	1,533

12 MONTHS ENDED SEPTEMBER 30, 2026

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	694	695	Not Yet Available									
Non-Union	838	837										
Non-Union Temporary	2	2										
Total	1,534	1,534	-	-	-	-	-	-	-	-	-	-

UGI UTILITIES, INC. - GAS DIVISION

MONTHLY LABOR DATA

$s in thousands

12 MONTHS ENDED SEPTEMBER 30, 2024

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	$ 5,021	$ 6,031	$ 4,567	$ 6,067	$ 5,587	$ 7,994	$ 6,539	$ 5,064	$ 5,129	$ 4,645	$ 7,171	$ 5,291
Expense Overtime	424	440	382	302	366	515	376	380	406	316	606	436
Capital Straight Time	4,534	4,265	3,793	4,502	4,200	6,483	4,382	4,350	4,428	4,349	6,631	4,643
Capital Overtime	191	127	99	85	138	253	187	236	205	217	441	301
Total	$ 10,170	$ 10,863	$ 8,841	$ 10,956	$ 10,292	$ 15,245	$ 11,483	$ 10,030	$ 10,167	$ 9,528	$ 14,849	$ 10,672

12 MONTHS ENDED SEPTEMBER 30, 2025

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	$ 4,832	$ 7,231	$ 4,859	$ 4,688	$ 4,637	$ 4,601	$ 8,070	$ 5,189	$ 5,006	$ 5,083	$ 4,992	$ 5,551
Expense Overtime	461	1,195	855	644	690	654	835	664	551	607	615	707
Capital Straight Time	4,544	7,471	5,277	4,590	5,038	4,292	6,807	4,565	4,584	4,768	4,859	5,093
Capital Overtime	365	45	30	27	28	27	39	31	32	30	32	29
Total	$ 10,201	$ 15,942	11,020	9,948	10,393	9,574	15,751	10,449	10,173	10,489	10,499	11,381

12 MONTHS ENDED SEPTEMBER 30, 2026

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	$ 5,230	$ 5,860	Not Yet Available									
Expense Overtime	479	577										
Capital Straight Time	3,128	6,495										
Capital Overtime	307	286										
Total	$ 9,145	$ 13,218	-	-	-	-	-	-	-	-	-	-

*Capital includes both capital and other non-expense time.

SDR-RR-27

Request:

Please provide a copy of all incentive compensation and/or bonus plans and provide the level of related payments included in cost of service.

Response:

Information regarding UGI Utilities' Management Incentive Plan, UGI Utilities Executive Annual Bonus Plan, UGI Corporate Executive Annual Bonus Plan and UGI Corporate Non-Executive Annual Bonus Plan are confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Please refer to Attachments SDR-RR-27.1 through SDR-RR-27.7 for a copy of all other incentive compensation plans which have been uploaded separately via the Commission's SharePoint site. Those materials will be served upon the parties via a secure OneDrive link.

The total employee incentive compensation and/or bonus expense included within the cost of service is $10,883,911 for the Fully Projected Future Test Year.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-28

Request:

Please provide the percentage wage rate increases granted by the Company by date and employee category for the three most recent calendar years and the current year to date.

Response:

Please see Attachment SDR-RR-28.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. – Gas Division
Wage Increases
2023-2026***

Bargaining Unit

	2023	2024	2025	2026
IBEW Local 777 (Former System Council U-22)	3.00%	3.00%	6.00%	4.50%
Gas Fitter-Utility Employee Local Union No. 600	3.00%	3.00%	3.00%	TBD*
IBEW Local 2244 (Scranton/Carbondale)	6.00%	4.25%	3.25%	3.00%
IBEW Local 2244 (Honesdale)	3.00%	4.50%	4.50%	3.50%
UWUA Locals 406, 407, 408, 529	5.00%	4.25%	3.50%	3.00%
UWUA Locals 332, 435, 554	3.00%	3.00%	3.00%	TBD*
Teamsters Local 429	3.00%	3.00%	3.00%	TBD*
Teamsters Local 326	3.00%	3.00%	3.00%	TBD*
ICWU/UFCW Local 570	3.00%	3.00%	3.00%	TBD*
Utility Workers Local 2799 (Huntingdon, Clearfield, Lock Haven)	3.00%	3.00%	3.00%	TBD*
Utility Workers Local 2799 (North Region)	3.00%	3.00%	3.00%	TBD*
IBEW Local 777 (Corrosion Control)	3.00%	3.00%	6.00%	N/A**
IBEW Local 777 (Operations Support)	3.00%	4.00%	4.00%	3.25%

Future Contractual Increases

UWUA Locals 406, 407, 408, 529 – 3.00% wage increase on 4/1/2027

IBEW Local 2244 (Scranton/Carbondale) – 3.00% wage increase on 8/1/2027

IBEW Local 2244 (Honesdale) – 3.50% wage increase on 4/1/2027

IBEW 777 – 3.50% wage increase on 4/1/2027

Non-Union Increases

2023 Actual Merit: 1.38% (exempt = 0.04% nonexempt = 3.53%)

2024 Actual Merit: 3.62% (exempt = 3.63% nonexempt = 3.60%)

2025 Actual Merit: 3.54% (exempt = 3.63% nonexempt = 3.45%)

2026 Actual Merit: TBD (exempt = TBD nonexempt = TBD)

**TBD based on collective bargaining or market analysis*

*** N/A IBEW Local 777 (Corrosion Control) joined IBEW Local 777 (former System Council U-22)*

****Does not include any programmatic market adjustments*

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to Standard Data Requests - Revenue Requirement
Delivered on January 28, 2026

SDR-RR-29

Request:

Please provide an analysis (description, dates and amounts) of any gains or losses on utility property sold for the lesser of the last three years or since the Company's last rate case or anticipated during the FTY. Explain how such amounts have been treated for ratemaking purposes.

Response:

There has not been a gain/loss recorded since the last UGI Gas Base Rate Case.

We anticipate proceeds from sales of vehicles during Fiscal Year 2026 (FTY) and Fiscal Year 2027 (FPFTY) of $600,000 each year. For ratemaking purposes, these proceeds are treated as net salvage.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-30

Request:

Please provide the level of each of the following which is included in the Company's cost of service by separate type and/or payee, which are incurred directly by the Company or are allocated or billed to the Company by affiliates or its parent company.

a. fines and penalties

b. contributions and donations

c. membership dues

d. lobbying expense

e. employee activity costs (e.g., picnics, parties, awards)

f. investor relations expenses

Response:

a. No costs for fines and penalties are included.

b. No costs for contributions and donations are included.

c. Please refer to Attachment SDR-RR-30.

d. No lobbying expenses are included.

e. The cost of service includes employee activity costs (e.g., picnics, parties, safety awards) in the amount of $583,036 for the fully projected future test year.

f. The cost of service includes allocated investor relations expenses in the amount of $232,572 for the fully projected future test year.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF COMPANY MEMBERSHIPS
FOR THE YEAR ENDED SEPTEMBER 30, 2027

Organization Name	2027	
AMERICAN GAS ASSOCIATION	779,316	*
GAS TECHNOLOGY INSTITUTE	371,457	
ENERGY ASSOCIATION OF PA	216,732	*
NORTHEAST GAS ASSOCIATION	59,419	
ECONOMIC DEVELOPMENT OF LANCASTER	32,500	
PA CHAMBER OF BUSINESS AND INDUSTRY	30,733	*
ENERGY SOLUTIONS CENTER	21,500	
LEHIGH VALLEY ECONOMIC DEVELOPMENT CORP	20,000	
GREATER READING ECONOMIC PARTNERSHIP	15,000	
LEBANON VALLEY ECONOMIC DEVELOPMENT CORP	7,500	
WYOMING VALLEY CHAMBER OF COMMERCE	7,000	
PENN NORTHEAST - GAS DIVISION	5,500	
BETHLEHEM ECONOMIC DEVELOPMENT CORP	5,000	
SCRANTON CHAMBER OF COMMERCE	3,750	
WYOMING COUNTY CHAMBER OF COMMERCE	2,500	
GREATER SUSQUEHANNA CHAMBER OF COMM	2,500	
PIPELINE ASSOCIATION FOR PUBLIC AWARENESS	2,500	
HARRISBURG REGIONAL CHAMBER & CREDC	2,000	
WEDCO - WAYNE ECONOMIC DEVELOPMENT COMPANY	1,750	
ORGANIZATIONS $1,500 & UNDER	6,823	
	$ 1,593,479	

* Excludes lobbying portion of dues.

SDR-RR-31

Request:

Please provide a description and the purpose for membership for each organization listed in the previous response.

Response:

Refer to response SDR-RR-32 for the purpose of memberships in industry organizations. The purpose of the Company's membership in other organizations is to improve the welfare, educational, social and economic climate in the Company's local communities, as well as to sponsor memberships for employees whose active participation in these organizations would be in the best interests of the Company, its customers, and the communities within which the Company serves.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-32

Request:

Please provide the level of payments made to industry organizations included in cost of service along with a description of each payee organization or project.

Response:

Please refer to Attachment SDR-RR-32 for the industry organization payments included in the cost of service. The description of each payee organization is provided below.

- The American Gas Association (AGA) is a trade association that represents more than 200 local energy companies that deliver clean natural gas throughout the United States.

- The Energy Association of Pennsylvania (EAP) is a trade association whose members include the electric and natural gas utilities operating in Pennsylvania.

- The Energy Solutions Center, Inc. (ESC) is a non-profit organization of energy utilities and equipment manufacturers that promotes energy efficient natural gas solutions and systems for use by residential, commercial, and industrial energy users.

- The Gas Technology Institute membership provides for participation in the Operations Technology Development Company (“OTD”), an associated company of the Gas Technology Institute. OTD is a collaborative effort to develop advanced technologies for the natural gas industry.

- The Northeast Gas Association (NGA) is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S.

- The Pipeline Association for Public Awareness is a nonprofit corporation established in 2004 to provide pipeline safety and emergency preparedness information to residents, businesses, farmers, excavators, emergency responders and public officials.

SDR-RR-32 (Continued)

- The Pennsylvania Chamber of Business and Industry (PA Chamber) is the state's largest business advocacy association, representing a wide range of businesses across all sectors.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF INDUSTRY ORGANIZATION PAYMENTS
FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2027

Organization Name	Included in Claim	Excluded from Claim*	Total Payment
American Gas Association	$ 779,316	$ 30,615	$ 809,931
Energy Association of Pennsylvania	216,732	6,703	223,435
Energy Soulutions Center	21,500	-	21,500
Gas Technology Institute	371,457	-	371,457
Northeast Gas Association	59,419	-	59,419
Pipeline Association for Public Awareness	2,500	-	2,500
PA Chamber of Business and Industry	30,733	30,733	61,467
	$ 1,481,657	$ 68,052	$ 1,549,709

* Expenses related to lobbying activities have been excluded from the cost of service.

SDR-RR-33

Request:

Please provide the following information related to the Company's membership in AGA:

a. Cost included in requested cost of service

b. Cost excluded from requested cost of service

c. Copy of the most recent audit report of AGA expenditures prepared by NARUC.

d. Most recent correspondence received from AGA which addresses the percentage of dues related to lobbying or other separate activities.

e. Policy statement, objective, purpose, etc. of AGA.

Response:

a. The cost of service includes membership fees paid to AGA in the amounts of $721,304 for historic, $736,494 for future and $779,316 for fully projected future test years, respectively.

b. The cost of service excludes membership fees paid to AGA for lobbying activities in the amounts of $28,156 for historic, $28,933 for future and $30,615 for fully projected future test years, respectively.

c. NARUC last performed an audit of AGA expenditures in 2002, for which the audit report has been provided in Attachment SDR-RR-33(c).

d. Please refer to Attachment SDR-RR-33(d).

e. Please refer to Attachment SDR-RR-33(e).

Prepared by or under the supervision of: Tracy A. Hazenstab

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 2002

March 2005

NARUC STAFF SUBCOMMITTEE ON ACCOUNTING AND FINANCE

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

N A R U C
National Association of Regulatory Utility Commissioners

March 2005

To: **The State Regulatory Commissions**

From: **The NARUC Staff Subcommittee on Accounting and Finance**

Re: **Transmittal of the 2002 Report on the Expenditures of the American Gas Association**

Dear State Regulatory Commissions:

This is the annual report on the expenditures of the American Gas Association (AGA) provided for your review and consideration. Hopefully you will find the information contained herein to be useful in helping you to decide which, if any, of the costs of the association you should approve for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities.

With the possible exception of expenses directly related to research and development relevant to utility operations, and a proportional amount of associated administrative overhead expense, these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit.

The Staff Subcommittee on Accounting and Finance is pleased to provide you with the AGA report for 2002 to allow you to review the information contained therein and to utilize it in a manner consistent with your commission's regulatory policies and practices.

Sincerely,

Thomas J. Ferris

Thomas J. Ferris
Chair
Staff Subcommittee on Accounting and Finance

Calculation of Lobbying Expenses Pursuant to
Internal Revenue Code Section 162(e)

The American Gas Association incurred lobbying expenses, as defined under IRC Section 162, of 2.28% of total member dues during calendar year 2002.

IRC Section 162 Definition of Lobbying

(e) Denial of deduction for certain lobbying and political expenditures
- (1) In general no deduction shall be allowed under subsection (a) for any amount paid or incurred in connection with -
  - (A) influencing legislation,
  - (B) participation in, or intervention in, any political campaign on behalf of (or in opposition to) any candidate for public office,
  - (C) any attempt to influence the general public, or segments thereof, with respect to elections, legislative matters, or referendums, or
  - (D) any direct communication with a covered executive branch official in an attempt to influence the official actions or positions of such official.
- (2) Exception for local legislation - In the case of any legislation of any local council or similar governing body -
  - (A) paragraph (1)(A) shall not apply, and
  - (B) the deduction allowed by subsection (a) shall include all ordinary and necessary expenses (including, but not limited to, traveling expenses described in subsection (a)(2) and the cost of preparing testimony) paid or incurred during the taxable year in carrying on any trade or business -
    - (i) in direct connection with appearances before, submission of statements to, or sending communications to the committees, or individual members, of such council or body with respect to legislation or proposed legislation of direct interest to the taxpayer, or
    - (ii) in direct connection with communication of information between the taxpayer and an organization of which the taxpayer is a member with respect to any such legislation or proposed legislation which is of direct interest to the taxpayer and to such organization, and that portion of the dues so paid or incurred with respect to any organization of which the taxpayer is a member which is attributable to the expenses of the activities described in clauses (i) and (ii) carried on by such organization.
- (3) Application to dues of tax-exempt organizations - No deduction shall be allowed under subsection (a) for the portion of dues or other similar amounts paid by the taxpayer to an organization which is exempt from tax under this subtitle which the organization notifies the taxpayer under section 6033(e)(1)(A)(ii) is allocable to expenditures to which paragraph (1) applies.
- (4) Influencing legislation - For purposes of this subsection -
  - (A) In general The term "influencing legislation" means any attempt to influence any legislation through communication with any member or employee of a legislative body, or with any government official or employee who may participate in the formulation of legislation.
  - (B) Legislation - The term "legislation" has the meaning given such term by section 4911(e)(2).
- (5) Other special rules
  - (A) Exception for certain taxpayers - In the case of any taxpayer engaged in the trade or business of conducting activities described in paragraph (1), paragraph (1) shall not apply to expenditures of the taxpayer in conducting such activities directly on behalf of another person (but shall apply to payments by such other person to the taxpayer for conducting such activities).
  - (B) De minimis exception
    - (i) In general Paragraph (1) shall not apply to any in-house expenditures for any taxable year if such expenditures do not exceed $2,000. In determining whether a taxpayer exceeds the $2,000 limit under this clause, there shall not be taken into account overhead costs otherwise allocable to activities described in paragraphs (1)(A) and (D).
    - (ii) In-house expenditures for purposes of clause (i), the term "in-house expenditures" means expenditures described in paragraphs (1)(A) and (D) other than -
      - (I) payments by the taxpayer to a person engaged in the trade or business of conducting activities described in paragraph (1) for the conduct of such activities on behalf of the taxpayer, or
      - (II) dues or other similar amounts paid or incurred by the taxpayer which are allocable to activities described in paragraph (1).
  - (C) Expenses incurred in connection with lobbying and political activities - Any amount paid or incurred for research for, or preparation, planning, or coordination of, any activity described in paragraph (1) shall be treated as paid or incurred in connection with such activity.
- (6) Covered executive branch official - For purposes of this subsection, the term "covered executive branch official" means -
  - (A) the President,
  - (B) the Vice President,
  - (C) any officer or employee of the White House Office of the Executive Office of the President, and the 2 most senior level officers of each of the other agencies in such Executive Office, and
  - (D) (i) any individual serving in a position in level I of the Executive Schedule under section 5312 of title 5, United States Code, (ii) any other individual designated by the President as having Cabinet level status, and (iii) any immediate deputy of an individual described in clause (i) or (ii).
- (7) Special rule for Indian tribal governments - For purposes of this subsection, an Indian tribal government shall be treated in the same manner as a local council or similar governing body.
- (8) Cross reference - For reporting requirements and alternative taxes related to this subsection, see section 6033(e).

Citation: IRC Sec. 6033(e)

AMERICAN GAS ASSOCIATION

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In accordance with agreement between
American Gas Association and NARUC Oversight Committee

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Internal Revenue Service Form 990

The American Gas Association is a non-profit and tax exempt organization required to file informational returns with the U.S. Internal Revenue Service (IRS). Public inspection of the completed American Gas Association Exempt Organization Return (IRS Form 990) may be made in accordance with IRS regulation by request directly to the Internal Revenue Service, Attention: FOI Reading Room, 1111 Constitution Avenue, N.W., Washington, D.C. 20224. The American Gas Association makes its Exempt Organization Return available for public inspection during normal business hours (9:00 a.m. - 5:00 p.m.) at the Association's principal office, 400 N. Capitol St., N.W., Washington, D.C. 20001, preferably by written request directed to Joseph L. Martin, AGA's Controller, at the same address. State public utility commissions that wish to receive a copy of AGA's Exempt Organization Return should also direct their request to Joseph Martin. Internal Revenue Service Form 4506-A may also be used to request copies of the return from the Internal Revenue Service if public inspection is not desired by the requestor. IRS may make a charge for its photocopying service.

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(1) Continued

Revenue Recognition

Membership dues are recognized as revenue in the year to which the membership applies. Dues received in advance are deferred. Publications revenue is recognized upon the sale of the related publication and meetings revenue is recognized when the related meetings are held.

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Functional Allocation of Expenses

The costs of providing the various programs and other activities have been summarized on a functional basis in the statements of activities. Accordingly, certain costs have been allocated among the programs and supporting services benefited. Salaries are charged directly to the programs and supporting services served. Fringe benefits are allocated to the programs and supporting services proportionate to salaries charged, and certain expenses benefiting all programs and supporting services are allocated based on the number of staff supporting each service.

Income Taxes

The Association is recognized as exempt from federal income tax under Section 501(c)(6) of the Internal Revenue Code, except for taxes on unrelated business income. Income tax expense on unrelated business activities totaled approximately $25,000 and $20,500 for the years ended December 31, 2002 and 2001, respectively.

The Association has elected to pay the federal proxy tax on behalf of its members on expenses related to lobbying activities. The proxy tax approximates $125,000 for both years ended December 31, 2002 and 2001.

Reclassifications

Certain reclassifications of prior year balances have been made to conform to the current year presentation.

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(2) Cash and Cash Equivalents and Marketable Securities

At December 31, 2002 and 2001, the components of cash and cash equivalents and marketable securities were as follows:

	2002	2001
Cash	$ 482,603	$ 461,013
Cash equivalents:		
Money market accounts	1,432,064	2,204,914
U.S. government agency obligations	599,760	-
Commercial paper	749,102	347,584
Total cash and cash equivalents	$ 3,263,529	$ 3,013,511
U.S. government agency obligations	$ 4,053,550	$ 4,322,497
Mortgage-backed securities	-	255,117
Corporate obligations	1,737,602	1,544,019
Other debt securities	9,128,124	9,968,957
Equity mutual funds and securities	5,757,285	6,980,682
Total marketable securities	$ 20,676,561	$ 23,071,272

(3) Property, Plant, and Equipment

Property, plant, and equipment are composed of the following as of December 31, 2002 and 2001:

	2002	2001
Leasehold improvements	$ 986,148	$ 949,311
Equipment	3,267,192	3,624,270
Furniture and fixtures	1,199,761	1,199,761
	5,453,101	5,773,342
Less accumulated depreciation and amortization	(2,844,837)	(2,557,526)
Property, plant, and equipment, net	$ 2,608,264	$ 3,215,816

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(4) Pension and Other Postretirement Benefits

The Association has the following noncontributory defined benefit pension plans:

- a qualified plan which covers substantially all Association employees,
- a non-qualified plan which is for employees who were determined to be eligible by the Association's Compensation Committee when the plan was created in 1985 (plan was frozen to new participants in 1986), and
- a non-qualified "excess" plan for those employees whose compensation exceeds the IRS limits for the qualified plan. This plan was approved by the Compensation Committee and is effective January 1, 2003.

These plans provide retirement benefits based on employees' years of services and compensation prior to retirement. In addition, there is an unfunded, nonqualified supplemental retirement benefit plan for the President and CEO that was approved by the Board of Directors in February 2001.

The funded plan's assets consist primarily of common stocks and U.S. government and corporate bonds.

The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans at December 31, 2002 and 2001:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Benefit obligation	$ 25,592,012	$ 23,168,922	$ 8,489,792	$ 7,554,951
Fair value of plan assets	19,832,983	23,282,900	4,203,939	5,037,630
Funded status	$ (5,759,029)	$ 113,978	$ (4,285,853)	$ (2,517,321)
Accrued benefit cost recognized in the statements of financial position	$ 1,531,068	$ 1,045,369	$ 850,289	$ 854,771
Intangible asset recognized in the statements of financial position	$ 98,428	$ -	$ -	$ -

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(4) Continued

Weighted-average assumptions:	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.50%	4.50%	N/A	N/A

Net periodic pension and other postretirement costs for 2002 and 2001 include the following components:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Pension (benefit) cost	$ 461,488	$ 139,626	$ 205,763	$ 23,285
Employer contribution	443,191	211,414	218,476	-
Plan participants' contributions	-	-	47,554	123,910
Benefits paid	1,576,467	1,341,069	545,110	594,492

In accordance with Statement of Financial Accounting Standard (SFAS) No. 87, *"Employers' Accounting for Pensions"*, the Association has recognized the required minimum liability represented by the excess of the accumulated benefit obligation over the plan assets at December 31, 2002 and 2001, which totaled $827,925 and $360,522, respectively. An intangible pension asset of $98,428, representing the unamortized prior service cost of the defined benefit plan, has been recognized within prepaid expenses and other assets in the accompanying statement of financial position as of December 31, 2002. The change in the total minimum liability of $368,975 is being recognized as a reduction to unrestricted net assets.

(Continued)

[redacted]

Invoice for Membership Dues

Date	Invoice Number
JUL 7, 2025	142775B

[redacted]
UGI UTILITIES, INC.
1 UGI DRIVE
DENVER, PA 17517

Description	Total
Dues for 2025 membership year: $733,443.00	
Third Quarterly Payment	$183,360.75
	$183,360.75

IMPORTANT IRS REQUIRED NOTICE

Dues payments, contributions or gifts to the American Gas Association are not tax deductible as charitable contributions for federal income tax purposes. However, they may be deductible as ordinary and necessary business expenses subject to restrictions imposed as a result of AGA's lobbying activities as defined by the Budget Reconciliation Act of 1993. AGA estimates that the nondeductible portion of your 2025 dues -- **the portion that is allocable to lobbying is 3.78%**.

PLEASE REMIT PAYMENT WITH COPY OF INVOICE TO:

Send payments by check to:

AMERICAN GAS ASSOCIATION
Post Office Box 79226
Baltimore, MD 21279-0226

Send payments electronically by ACH to:

Account Holder: American Gas Association
Bank: [redacted]
Address: [redacted]
ABA Number: [redacted]
Account Number: [redacted]
Reference: [redacted]

Please refer any questions to Joseph Pierce at (202) 824-7256 or dues@aga.org.

American Gas Association (AGA)

Source: https://www.aga.org/about/

About:

The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 78 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — more than 74 million customers — receive their gas from AGA members. Today, natural gas meets one-third of the United States' energy needs.

Mission:

The American Gas Association (AGA) develops and advocates for informed, innovative, and durable policy that fulfills our nation's energy needs, environmental aspirations and economic potential. Additionally, the AGA provides state-of-the-art solutions for AGA members to safely and securely deliver reliable and affordable natural gas and advanced fuels to homes and businesses across the nation.

Vision:

Provide America with essential life-sustaining energy.

SDR-RR-34

Request:

Please provide a copy of the most recent FERC audit findings, the Company's response and final disposition of audit exceptions.

Response:

A copy of the Company's most recent FERC Audit findings can be found at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210114-3022&optimized=false.

Please see Attachment SDR-RR-34 for the Company’s response to those findings.

Prepared by or under the supervision of: Amy M. Keller

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UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517
(610) 796-3400

Via Electronic Delivery

February 12, 2021

Kristen Fleet
Acting Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE, Room 51-59
Washington, DC 20426

RE: UGI Utilities, Inc.
Docket No. FA20-3-000
Implementation Plan in Response to January 14, 2021 Audit Report

Dear Ms. Fleet:

In conjunction with UGI Utilities, Inc.'s ("UGIU's") January 8, 2021 response to the Federal Regulatory Commission (the "Commission") audit report dated January 14, 2021 ("Audit Report"), please accept UGIU's plan of implementing the audit recommendations contained in the Audit Report.

As set forth in the attached implementation plan, UGIU accepts many of the Division of Audit and Accounting's ("DAA's") audit findings and recommendations in the Audit Report and provides documented corrective action plans and timelines for each of the 50 recommendations. UGIU will make quarterly submissions to DAA describing the progress made with respect to each recommendation, beginning within 30 days after the end of the first calendar quarter, and continuing until all the corrective actions are completed. UGIU's submission of its implementation plan is without prejudice to, or waiver of its rights, including its right to contest the Commission's authority generally to make retroactive changes to, or require refunds for, rates that have been allowed to go into effect.

Should you have any questions concerning UGIU's response, please direct your questions to [redacted], or me, at [redacted].

Sincerely,

[redacted]

Controller

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INTRODUCTION

UGI Utilities, Inc. ("UGIU" or "the Company") hereby submits the following Implementation Plan ("Plan") in response to the Division of Audits and Accounting ("DAA") within the Office of Enforcement ("OE") of the Federal Energy Regulatory Commission's ("FERC") audit covering the period January 1, 2017 through July 29, 2020.

The Plan is organized to address each finding and recommendation contained in the OE'S audit report dated January 14, 2021. For each finding, the Plan states the Company's response, and for each recommendation, the Plan states the action to be taken, the individual responsible, and the expected completion date.

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

1. EXCESS ACCUMULATED DEFERRED INCOME TAX

UGIU improperly recorded the excess Accumulated Deferred Income Taxes (ADIT) related to the 2017 Tax Cuts and Jobs Act in Account 282, Accumulated Deferred Income Taxes – Other Property and Account 190, Accumulated Deferred Income Taxes. In addition, UGIU improperly excluded excess and deficient ADIT, created as a result of the 2017 Tax Cuts and Jobs Act, from its wholesale transmission formula rate computation. As a result, UGIU overstated its annual transmission revenue requirement by approximately $357,476 and overbilled wholesale transmission customers in 2018.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 1

Implement procedures to ensure that deficient and excess ADIT asset and liability amounts are included in rate base for the computation of the annual transmission revenue requirement.

Action: On May 15, 2020, UGIU submitted an Order No. 864 Compliance Filing making updates to its formula rate to encompass the impacts of the TCJA relates to such items as excess ADIT and its subsequent amortization. Further, in filing its 2019 FERC formula rate, the Company included the excess ADIT in its wholesale transmission formula rate computation. Lastly, the Company made correcting entries to reclass the deferred tax asset associated with the excess ADIT from account 190 to account 282.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Completed

RECOMMENDATION NO. 2

Revise its accounting policies and procedures to ensure that the effect of changes in tax laws or tax rates are implemented in accordance with the Commission's accounting guidance in Docket No. AI93-5.

Action: UGIU will internally develop and deliver training to its staff to ensure that the effect of changes in tax laws or tax rates are implemented in accordance with the Commission's accounting guidance. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 3

Submit correcting journal entries, within 60 days of issuance of this audit report, with proposed accounting entries and supporting documentation to DAA that reflect corrections to recorded excess and deficient ADIT in the appropriate USofA accounts.

Action: UGIU will submit correcting journal entries reflecting corrections to recorded excess and deficient ADIT in the appropriate USofA accounts to DAA.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 4

Submit a refund analysis, within 60 days of issuance of the audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of excess and deficient ADIT asset and liability amounts excluded from the transmission formula rates in 2018, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 4.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 5

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

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Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 6

Refund amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 6.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

2. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

UGIU's method for computing its AFUDC rate was deficient. Specifically, UGIU improperly excluded short-term debt, as the first source of financing construction, in calculating its AFUDC rate. In addition, UGIU improperly included Account 216.1, Unappropriated Undistributed Subsidiary Earnings, and Account 219, Accumulated Other Comprehensive Income, in the equity component to compute its AFUDC rate. Also, UGIU improperly used its fiscal year-end book balance for long-term debt and common equity amounts when computing its AFUDC rate rather than the calendar year-end balances reported in its FERC Form No. 1 during the audit period. As a result, UGIU overaccrued AFUDC amounts included in utility plant accounts by approximately $436,000 from 2017 to 2019 and overbilled wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations. The Company has calculated the overaccrued amount related to transmission customers to be approximately $58,000.

RECOMMENDATION NO. 7

Revise and implement procedures to ensure that AFUDC rate calculations are consistent with Order Nos. 561 and 561-A, EPI No. 3 (A)(17), and other applicable Commission requirements.

Action: During 2019, UGIU revised its procedures to ensure that the AFUDC rate calculations are consistent with applicable Commission requirements.

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 8

Revise its procedures to ensure that it includes short-term debt in the computation of the AFUDC rate for its electric utility business.

Action: During 2019, UGIU revised its procedures to ensure that short-term debt is included in the computation of the AFUDC rate for its electric utility business.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 9

Revise its procedures to exclude Account 216.1 and Account 219 balances from the equity components used to derive its AFUDC rate.

Action: During 2019, UGIU revised its procedures to exclude Account 216.1 and Account 219 balances from the equity components used to derive its AFUDC rate.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 10

Revise its procedures to ensure that it computes AFUDC rates using the calendar year-end balances reported in its FERC Form No. 1 for common equity, preferred stock, and long-term debt.

Action: UGIU will file a request for waiver to continue its practice of using its fiscal year-end balances for common equity, preferred stock and long-term debt balances in its AFUDC rate computation.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: December 31, 2021

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

RECOMMENDATION NO. 11

Provide training to its staff on the revised procedures implemented under Recommendation Nos. 7, 8, 9, and 10. Provide periodic training in these areas as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised procedures implemented under Recommendation Nos. 7, 8, 9, and 10. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 12

Recalculate its accrued AFUDC, in a manner consistent with EPI No. 3(A)(17) that corrects for the improper exclusion of short-term debt, improper inclusion of Account 216.1 and 219 balances, and improper use of fiscal year-end book balances for common equity, preferred stock, and long-term debt from 2012 through the date of issuance of the audit report.

Action: UGIU will recalculate its accrued AFUDC, as specified in recommendation no. 12.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 13

Submit proposed accounting entries and supporting documentation to DAA that reflect the correction of the CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC within 60 days of issuance of the audit report.

Action: UGIU will submit proposed accounting entries and supporting documentation as specified in recommendation no. 13 to DAA.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

RECOMMENDATION NO. 14

Submit a refund analysis, within 60 days of issuance of the audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of excess AFUDC included in the transmission formula rates since 2017, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains all items listed in recommendation no. 14.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 15

Revise CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC after receiving DAA's assessment of the proposed accounting entries per Recommendation No. 13 and restate and footnote the FERC Form No. 1 for current and comparative years as necessary.

Action: UGIU will revise CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC and restate and footnote the FERC Form No. 1 for current and comparative years as necessary.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: FERC Form No. 1 will be updated as necessary as described in recommendation No. 15 in the Company's first FERC Form No. 1 dated after the receipt of the DAA's assessment of the submitted proposed accounting entries.

RECOMMENDATION NO. 16

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

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Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 17

Refund the amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 17.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

3. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

UGIU improperly included ADIT related to SFAS 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, as an input to its wholesale transmission formula rate contrary to the directives of its tariff. As a result, UGIU overstated the ADIT balances included in its wholesale transmission formula rate, which led to overstating its annual transmission revenue requirements and overbilling its wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 18

Revise and implement procedures, policies, and controls to track and review the transmission formula rate inputs and calculations for accuracy, completeness, and compliance with UGIU's Commission approved formula rate.

Action: UGIU corrected this inadvertent formula error in filing its 2020 FERC formula rate.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Completed

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UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

RECOMMENDATION NO. 19

Provide training to staff on the revised wholesale transmission formula rate procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised wholesale transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 20

Submit a refund analysis to DAA, within 60 days of issuance of this audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the inclusion SFAS 106 amounts plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 20.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 21

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.
Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

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RECOMMENDATION NO. 22

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 22.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

4. COMMON PLANT O&M EXPENSES

UGIU improperly included common plant O&M expenses, that were also included as A&G expenses, in its wholesale transmission formula rate. As a result, UGIU double counted expenses associated with common plant, and consequently, overstated its wholesale transmission revenue requirement by approximately $423,454 during the audit period. This led UGIU to overbill its wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 23

Develop and implement procedures, policies, and controls to ensure expenses included in the transmission formula rate are not included in multiple areas.

Action: UGIU will develop and implement procedures, policies, and controls, focusing on coding of the Company's natural chart of accounts, mapping to the FERC chart of accounts, and how those amounts are inputted to the Company's formula rate. This will ensure expenses included in the transmission formula rate are not included in multiple areas.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

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RECOMMENDATION NO. 24

Provide training to staff on the revised transmission formula rate procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 25

Submit a refund analysis, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation of refunds to UGIU's wholesale transmission customers since 2017, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) for which refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 25.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 26

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

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RECOMMENDATION NO. 27

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 27.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

5. TRANSMISSION REVENUE CREDITS

UGIU understated its revenue credits that were used to reduce the annual transmission revenue requirements calculated by its wholesale transmission formula rate by improperly excluding certain transmission- related revenues recorded in Account 454, Rent from Electric Property. Additionally, UGIU improperly accounted for rental revenue associated with third parties' usage of its utility assets by recording such revenue in Account 418, Nonoperating Rental Income. As a result, UGIU understated the revenue credits includible in its wholesale transmission formula rate, which led to an overstatement of its annual transmission revenue requirements.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 28

Develop and implement procedures and policies to track, report, review, and account for wholesale transmission revenues consistent with Commission accounting and ratemaking requirements.

Action: UGIU will develop and implement procedures and policies to track, report, review, and account for wholesale transmission revenues consistent with Commission accounting and ratemaking requirements. This will include proper identification of wholesale transmission revenues at recognition and adjustments to the coding, as necessary, as well as review checks to ensure that all revenues are recorded to the proper FERC accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

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IMPLEMENTATION PLAN FOR
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RECOMMENDATION NO. 29

Provide training to staff on the revised accounting and wholesale transmission revenue procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised accounting and wholesale transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 30

Perform an analysis of rental income accounts to identify revenues that were not properly credited to wholesale transmission customers through UGIU's transmission formula rates for the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: UGIU will perform and submit the results of the analysis of rental income as specified in recommendation no. 30 to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 31

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the exclusion of revenue credits plus interest; (2) determinative components of the refund; (3) refund method; (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 31.

Individual Responsible: Assistant Controller

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Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 32

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 33

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 33.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

6. ACCOUNTING FOR AFFILIATE TRANSACTIONS

UGIU misclassified various expenses associated with services provided by its parent company in Account 923, Outside Services Employed. Also, UGIU did not consistently apply its internally calculated, cost allocation percentages used to allocate costs between UGIU's electric utility business and its gas utility business. These allocation errors resulted in improper amounts being included in UGIU's wholesale transmission formula rate.

UGIU Response

UGIU accepts this finding and the recommendations.

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RECOMMENDATION NO. 34

Revise and implement procedures and policies to track, report, review, and account for UGI Corporation allocated expenses consistent with Commission accounting requirements.

Action: UGIU will revise and implement procedures and policies to track, report, review, and account for UGI Corporation allocated expenses consistent with Commission accounting requirements. This will include getting detail of all allocated expenses and properly assigning those to respective FERC accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 35

Revise and implement procedures, policies and controls to ensure the correct allocation factors are used to calculate and allocate common expenses recorded in the A&G accounts for the electric utility business.

Action: UGIU has revised its procedures, policies and controls to ensure the correct allocation factors are used to calculate and allocate common expenses recorded in the A&G accounts for the electric utility business. With the Company's implementation of a new ERP system, SAP, in July of 2019, employees are instructed to code common A&G costs to shared cost centers, which are then systematically allocated to the electric utility business based on the Company's annual MWF allocation. No manual allocation should be completed going forward. This methodology is also documented in UGIU's updated 2020 Cost Allocation Manual. Accounting also performs periodic checks to ensure that all costs coded to the shared cost centers are properly allocated.

Individual Responsible: Assistant Controller

Expected Completion Date: Completed

RECOMMENDATION NO. 36

Train staff on the procedures and policies and provide periodic training, as needed.

Action: UGIU will internally develop and deliver training to its staff specifying how UGI Corporation allocated expenses and UGIU common expenses should be coded to ensure that they are properly allocated and consistent with the Commission accounting requirements. In addition, UGIU will formalize future periodic training with internal and external counsel to

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ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 37

Perform an analysis of A&G expense accounts to identify common expenses that were allocated using the incorrect allocation percentages during the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: In conjunction with its response to recommendation no. 43, UGIU will perform an analysis of A&G expense accounts to identify expenses that were incorrectly allocated or improperly recorded. UGIU's analysis will consist of a reasonable sample of A&G expenses during the audit period. UGIU will submit the results of the analysis of A&G expense accounts to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 38

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper allocation of common expenses recorded in A&G accounts as identified pursuant to the analysis performed in response to Recommendation No. 43, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 38.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

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RECOMMENDATION NO. 39

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 40

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 40.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

7. ACCOUNTING FOR ADMINISTRATIVE AND GENERAL EXPENSES

UGIU improperly recorded various A&G expenses in a manner contrary to the Commission's accounting regulations. As a result, UGIU overbilled wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 41

Revise policies and procedures to ensure that UGIU properly accounts for expenditures in its books and records.

Action: UGIU will revise its policies and procedures to ensure that expenditures are properly accounted for. This will include proper coding of invoices, as well as policies to periodically

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review the Company's mapping from its natural chart of accounts to the FERC chart of accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 42

Provide training to its staff on the revised procedures for properly accounting for expenditures in UGIU's books and records. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised procedures for properly accounting for expenditures in UGIU's books and records. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 43

Perform an analysis of A&G expense accounts to identify expenses that were inappropriately recovered through UGIU's transmission formula rate and the related customer billings, such as advertising, donations, lobbying, distribution O&M costs, legal costs, and asset insurance improperly charged to accounts included in the transmission formula rate during the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: In conjunction with its response to recommendation no. 37, UGIU will perform an analysis of A&G expense accounts to identify expenses that were incorrectly allocated or improperly recorded. UGIU's analysis will consist of a reasonable sample of A&G expenses during the audit period. UGIU will submit the results of the analysis of A&G expense accounts to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

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RECOMMENDATION NO. 44

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper accounting for expenses recorded in A&G accounts as identified pursuant to the analysis performed in response to Recommendation No. 43, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 44.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 45

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 46

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 46.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

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8. FILING OF DEPRECIATION RATES WITH THE COMMISSION

UGIU did not file its depreciation rate schedule with the Commission when depreciation rates were changed. This hindered the Commission's and other interested parties' ability to timely review and monitor UGIU's depreciation rates, which impact prices charged for wholesale transmission services through the formula rate.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 47

Develop and implement processes and procedures to ensure that depreciation rates and related studies are filed with the Commission when depreciation rates are changed.

Action: UGIU will develop and implement a process to ensure that depreciation rates and related studies are filed with the Commission when depreciation rates are changed.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 48

File current depreciation studies with the Commission relating to UGIU's current annual transmission revenue requirement within 60 days of issuance of this audit report.

Action: UGIU will file current depreciation studies with the Commission relating to UGIU's current annual transmission revenue requirement.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

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9. FERC FORM NO. 1 REPORTING

UGIU did not properly follow the FERC Form No. 1 instructions and, therefore, did not report all required information in its FERC Form No. 1 filings.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 49

Revise and strengthen documented policies, procedures, and practices to ensure information reported in the FERC Form No. 1 is correct, accurate, and consistent with the instructions of the form.

Action: UGIU will revise and strengthen policies, procedures, and practices to ensure information reported in the FERC Form No. 1 is correct, accurate and consistent with the instructions.

Individual Responsible: Assistant Controller

Expected Completion Date: Time of filing UGIU's December 31, 2020 FERC Form No. 1.

RECOMMENDATION NO. 50

Provide training to staff on the revised FERC Form No. 1 policies, procedures, and practices. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised FERC Form No. 1 policies, procedures, and practices. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

SDR-RR-35

Request:

Please provide the annual level of forfeited discounts or late payment charges for the preceding three calendar years. Identify the level of sales revenue with which these are associated.

Response:

Please see Attachment SDR-RR-35.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
FORFEITED DISCOUNTS AND LATE PAYMENT CHARGES SCHEDULE
FOR THE YEARS ENDED SEPTEMBER 30
(thousands of dollars)

	2023	2024	2025
Forfeited Discounts and Late Payment Charges	$ 6,765	$ 5,573	$ 5,460
Sales Revenue[1]	$ 1,196,572	$ 1,012,009	$ 1,134,981

[1] Includes billed revenue only

SDR-RR-36

Request:

If not reflected in the lead-lag study, please provide a listing of the various types of employee withholdings, garnishments and other employee funds held by the Company for remittance at a later date.

Response:

United Way
Operation Share
Union Dues
Potter Game Club
Voluntary Employee Purchased Insurance Premiums
Medical, Dental and Vision
Flexible Spending Account
Health Saving Account
Political Action Committee
UGI Stock Purchase Plan
Other Various Wage Attachments (Federal, State Taxes)
Garnishments (Child Support, Creditor)
Retirement Plans

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-37

Request:

Please provide all detailed work papers supporting the adjustments to rate base and operating income.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Sections C and D.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-38

Request:

Please provide a copy of the Company's most recent SFAS 106 plan actuarial study.

Response:

UGI Gas' most recent SFAS 106 plan actuarial studies were conducted at the end of Fiscal Year 2025. Please refer to Attachment SDR-RR-38 for a copy of the reports issued as a result of these studies.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. Consolidated Postretirement Welfare Plans

Consolidated Actuarial Valuation Report Benefit Cost for Fiscal Year Beginning October 1, 2024 under US GAAP

Employer Contributions for Plan Year Beginning January 1, 2025

September 2025

wtwco.com

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Purposes of valuation

UGI Utilities, Inc. (the Company) engaged Willis Towers Watson US LLC ("WTW") to value the Company's other postretirement benefit plans.

As requested by the Company, this report documents the results of an actuarial valuation of the Plans:

- UGI Utilities Postretirement Welfare Plan (Utilities)
- Central Penn Gas Postretirement Welfare Plan (CPG)
- Penn Natural Gas Postretirement Welfare Plan (PNG)

The primary purpose of this valuation is to determine the Net Periodic Postretirement Benefit Cost/(Income) (Benefit Cost), in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715) for the fiscal year ending September 30, 2025. It is anticipated that a separate report will be prepared for year-end financial reporting purposes. This report also includes plan reporting information in accordance with FASB Accounting Standards Codification Topic 965 (ASC 965) and the estimated maximum tax-deductible contribution for the tax year in which the 2024 plan year ends as allowed by the Internal Revenue Code. The maximum tax-deductible contribution should be finalized in consultation with UGI Utilities, Inc.'s tax advisor.

Limitations

This valuation has been conducted for the purposes described above and may not be suitable for any other purpose. In particular, please note the following:

1. The expected contribution to the other postretirement benefits plan(s) has been set at $0. Note that any significant change in the amounts contributed or expected to be contributed in 2025 from what is disclosed at September 30, 2024 may require disclosure in the interim financial statements, but should not affect the expected return on plan assets absent a remeasurement for another purpose.
2. There may be certain events that have occurred since the valuation date that are not reflected in the current valuation. See Subsequent Events in the Basis for Valuation section below for more information.
3. This report does not present liabilities on a plan termination basis, for which a separate extensive analysis would be required. No funded status measure included in this report is intended to assess, and none may be appropriate for assessing, the sufficiency of plan assets to cover the estimated cost of settling benefit obligations, as all such measures differ in some way from plan termination obligations. In addition, funded status measures shown in this report do not reflect the current costs of settling obligations by offering immediate lump sum payments to participants and/or purchasing annuity contracts for the remaining participants (e.g., insurer profit, insurer pricing of contingent benefits and/or provision for anti-selection in the choice of a lump sum vs. an annuity).
4. The comparisons of plan obligations as determined for accounting and financial reporting purposes to plan assets presented in this report cannot be relied upon to determine the need for nor the amount of required future plan contributions. Nevertheless, such comparisons may be useful to assess the need for future contributions because they reflect current interest rates at the measurement date in determining benefit obligations. However, asset gains and losses, demographic

experience different from assumed, changes in interest rates, future benefit accruals, if any, and other factors will all affect the need for and amount of future contributions. In addition, if a plan is not required by law to be funded, benefit payments may also be paid directly by the plan sponsor as they come due.

Section 1 : Summary of key consolidated results

1.1 Benefit cost, plan assets & obligations

All monetary amounts shown in US Dollars

Fiscal Year Beginning		10/01/2024	10/01/2023
Benefit Cost/ (Income)	Net Periodic Postretirement Benefit Cost/(Income)	(1,003,524)	(549,522)
	Benefit Cost/(Income) due to Special Events	0	0
	Total Benefit Cost/(Income)	(1,003,524)	(549,522)
Measurement Date		**10/01/2024**	**10/01/2023**
Plan Assets	Fair Value of Plan Assets (FVA)	22,154,498	17,556,345
	Actual Return on Fair Value of Plan Assets during Prior Year	28.2%	14.5%
Benefit Obligations	Accumulated Postretirement Benefit Obligation (APBO)	(10,830,754)	(9,449,841)
Funded Ratio	Fair Value of Plan Assets to APBO	204.5%	185.8%
Accumulated Other Comprehensive (Income)/Loss (Pre-tax)	Net Prior Service Cost/(Credit)	(16,862)	(90,430)
	Net Loss/(Gain)	(5,716,838)	(2,975,552)
	Total Accumulated Other Comprehensive (Income)/Loss (pre-tax)	(5,733,700)	(3,065,982)
Assumptions	Discount rate		
	• Utilities	5.05%	6.05%
	• CPG	5.05%	6.02%
	• PNG	5.21%	6.13%
	Expected Long-Term Rate of Return on Plan Assets	5.25%	5.25%
Participant Data	Census Date	10/1/2024	10/1/2023

1.2 Comments on results

The consolidated actuarial gains/(losses) due to demographic experience, including any assumption changes, and investment return different from assumed during the prior year were $(1,060,488) and $3,998,588 respectively.

Change in net periodic cost and funded position

The net periodic cost decreased from $(549,522) in fiscal 2024 to $(1,003,524) in fiscal 2025 and the funded position improved from $8,106,504 to $11,323,744.

Significant reasons for these changes include the following:

- The actual return on the fair value of plan assets since the prior measurement date was greater than the expected return on plan assets, which improved the funded position.
- The discount rate used to measure APBO decreased 100 basis points for Utilities, 97 basis points for CPG, and 92 basis points for PNG compared to the prior year, which increased the net periodic cost and decreased the funded position.

Effects of Health Care Reform

This valuation reflects our understanding of the relevant provisions of the Patient Protection and Affordable Care Act (PPACA) and Health Care and Education Reconciliation Act (HCERA), and subsequent legislation (the SECURE Act of 2019) that eliminated the Cadillac tax, medical device tax and health insurance issuer tax. It also reflects our understanding of the effects of the Inflation Reduction Act of 2022 on retiree medical costs. It is possible that future guidance may conflict with our understanding of these laws based on currently available guidance and could therefore affect the results shown in this report. The valuation does not anticipate the effects of any additional possible future changes.

1.3 Basis for valuation

Appendix A summarizes the assumptions, methods and models used in the valuation. Appendix B summarizes our understanding of the principal provisions of the plans being valued. Both of these appendices include a summary of any changes since the prior valuation. Unless otherwise described below under Subsequent Events, assumptions were selected based on information known as of the measurement date.

Subsequent events

None.

Additional information

The Inflation Reduction Act (IRA) was signed on August 16, 2022. This new law includes health care provisions related to Medicare and healthcare financing. While guidance is still forthcoming, the potential effect of the new legislation has been considered in preparing these results. Based on the information available, and the specific plan provisions, changes were not made to assumptions. Additional changes may be reflected in future valuations as more guidance becomes available and actual plan experience is used to inform future expectations.

Actuarial certification

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. However, please note the information described below regarding this valuation.

Reliances

In preparing the results presented in this report, we have relied on information regarding plan provisions, participants, assets, and sponsor accounting policies and methods provided by the Company and other persons or organizations designated by the Company. See the Sources of Data and Other Information section of Appendix A for further details. We have relied on all the data and information provided as complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by the Company, may produce materially different results that could require that a revised report be issued.

Measurement of benefit obligations, plan assets and balance sheet adjustments

Census date/measurement date

The measurement date is October 1, 2024. The benefit obligations were measured as of October 1, 2024 and are based on participant data as of the census date, which is displayed by Plan in Appendix C.

Plan assets and balance sheet adjustments

Information about the fair value of plan assets and the general ledger account balances for the other postretirement benefit plans cost at September 30, 2024, which reflect the expected funded status of the plans before adjustment to reflect the funded status based on the year-end measurements, and differences between the expected Medicare Part D subsidies and amounts received during the year was reviewed for reasonableness and consistency, but no audit was performed.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for tax effects. Any tax effects in AOCI should be determined by the Company in consultation with its tax advisors and independent accountants.

Assumptions and methods under U.S. GAAP

As required by U.S. GAAP, the actuarial assumptions and methods employed in the development of the other postretirement benefit cost and other financial reporting have been selected by the Company. WTW has evaluated the assumptions used and believes that they do not significantly conflict with what would be reasonable. In addition, we believe that the combined effect of assumptions is expected to have no

significant bias. See Appendix A for a description of each significant assumption used and our rationale for concluding that it does not significantly conflict with what would be reasonable.

U.S. GAAP requires that each significant assumption "individually represent the best estimate of the plan's future experience solely with respect to that assumption."

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated by WTW, we believe do not significantly conflict with what would be reasonable. Other actuarial assumptions could also be considered to not significantly conflict with what would be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

A summary of the assumptions, methods and sources of data and other information used is provided in Appendix A. Note that any subsequent changes in methods or assumptions for the October 1, 2024 measurement date will change the results shown in this report.

Certain models (as described in ASOP No. 56) were used in preparing the information presented herein. Further information on these models can be found in Appendix A.

Nature of actuarial calculations

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. Any rounding (or lack thereof) used for displaying numbers in this report is not intended to imply a degree of precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions, changes in economic or demographic assumptions, increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period), and changes in plan provisions or applicable law. Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements. Retiree group benefits models necessarily rely on the use of approximations and estimates, and are sensitive to changes in these approximations and estimates. Small variations in these approximations and estimates may lead to significant changes in actuarial measurements.

See Basis for Valuation in Section 1 above for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

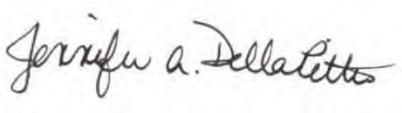
Limitations on use

This report is provided subject to the terms set out herein and in our engagement letter dated August 28, 2023 and any accompanying or referenced terms and conditions.

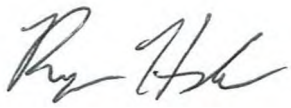
The information contained in this report was prepared for the internal use of the Company and its independent accountants in connection with our actuarial valuation of the other postretirement benefit plans as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. The Company may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require the Company to provide them this report, in which case the Company will use best efforts to notify WTW in advance of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without WTW's prior written consent. WTW accepts no responsibility for any consequences arising from any party other than UGI Corporation relying on this report or any advice relating to its contents.

Professional qualifications

The undersigned are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to other postretirement benefit plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Willis Towers Watson US LLC.



Jennifer Della Pietra, ASA, EA
Senior Director, Retirement
September 2025



Ryan Holden, FSA, EA
Associate Director, Retirement
September 2025

Section 2 : Consolidated accounting exhibits

2.1 Balance sheet asset/(liability)

All monetary amounts shown in US Dollars

Measurement Date		10/01/2024	10/01/2023
A	**Development of Balance Sheet Asset/(Liability)[1]**		
1	Accumulated postretirement benefit obligation (APBO)	(10,830,754)	(9,449,841)
2	Fair value of plan assets (FVA) [2]	22,154,498	17,556,345
3	Net balance sheet asset/(liability)	11,323,744	8,106,504
B	**Current and Noncurrent Classification[3]**		
1	Noncurrent asset	11,323,744	8,106,504
2	Current liability	N/A	N/A
3	Noncurrent liability	N/A	N/A
4	Net balance sheet asset/(liability)	11,323,744	8,106,504
C	**Accumulated Other Comprehensive (Income)/Loss**		
1	Net prior service cost/(credit)	(16,862)	(90,430)
2	Net loss/(gain)	(5,716,838)	(2,975,552)
3	Accumulated other comprehensive (income)/loss[4]	(5,733,700)	(3,065,982)
D	**Assumptions and Dates**		
1	Discount rate		
	• Utilities	5.05%	6.05%
	• CPG	5.05%	6.02%
	• PNG	5.21%	6.13%
2	Census date	10/1/2024	10/1/2023

1 Whether any amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.
2 Excludes receivable contributions.
3 The current liability (for each underfunded plan) was measured as the discounted value of benefits expected to be paid over the next 12 months in excess of the fair value of the plan's assets at the measurement date.
4 Amount shown is pre-tax and should be adjusted by plan sponsor for tax effects.

2.2 Changes in plan obligations and assets

All monetary amounts shown in US Dollars

		Period Beginning	10/01/2024	10/01/2023
A	**Change in Accumulated Postretirement Benefit Obligation (APBO)**			
1		APBO at beginning of prior fiscal year	9,449,841	9,921,489
2		Employer service cost	68,450	83,845
3		Interest cost	560,757	545,715
4		Actuarial loss/(gain)	1,060,488	(743,943)
5		Plan participants' contributions	8,939	8,162
6		Benefits paid from plan assets	(317,721)	(365,427)
7		Benefits paid from Company assets	0	0
8		Medicare Part D subsidy	0	0
9		Administrative expenses paid [1]	0	0
10		Plan amendments	0	0
11		Acquisitions/(divestitures)	0	0
12		Curtailments	0	0
13		Settlements	0	0
14		Special/contractual termination benefits	0	0
15		APBO at beginning of current fiscal year	10,830,754	9,449,841
B	**Change in Plan Assets**			
1		Fair value of plan assets at beginning of prior fiscal year	17,556,345	15,668,572
2		Actual return on plan assets	4,906,935	2,245,038
3		Employer contributions	0	0
4		Plan participants' contributions	8,939	8,162
5		Benefits paid	(317,721)	(365,427)
6		Administrative expenses paid	0	0
7		Acquisitions/(divestitures)	0	0
8		Settlements	0	0
9		Fair value of plan assets at beginning of current fiscal year	22,154,498	17,556,345

[1] Only if future expenses are accrued in APBO through a load on service cost.

2.3 Summary of net balances

Refer to Appendix C for balances by plan.

2.4 Development of plan assets for benefit cost

All monetary amounts shown in US Dollars

			Fair Value	Market-Related Value
A	**Reconciliation of Plan Assets**			
	1	Plan assets at 09/30/2023	17,556,345	17,556,345
	2	Actual return on plan assets	4,906,935	4,906,935
	3	Employer contributions	0	0
	4	Plan participants' contributions	8,939	8,939
	5	Benefits paid	(317,721)	(317,721)
	6	Administrative expenses paid	0	0
	7	Acquisitions/(divestitures)	0	0
	8	Settlements	0	0
	9	Plan assets at 09/30/2024	22,154,498	22,154,498
B	**Rate of Return on Invested Assets**			
	1	Weighted invested assets	17,401,953	
	2	Rate of return	28.2%	
C	**Investment Loss/(Gain)**			
	1	Actual return	4,906,935	
	2	Expected return	908,347	
	3	Loss/(gain)	(3,998,588)	

2.5 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

Fiscal Year Ending		09/30/2025	09/30/2024
A	**Total Benefit Cost**		
1	Employer service cost	78,219	68,450
2	Interest cost	539,177	560,757
3	Expected return on plan assets	(1,149,471)	(908,347)
4	Subtotal	(532,075)	(279,140)
5	Net prior service cost/(credit) amortization	(16,862)	(73,568)
6	Net loss/(gain) amortization	(454,587)	(196,814)
7	Subtotal	(471,449)	(270,382)
8	Net periodic postretirement benefit cost/(income)	(1,003,524)	(549,522)
9	Curtailment (gain)/loss	0	0
10	Settlement (gain)/loss	0	0
11	Special/contractual termination benefits	0	0
12	Total benefit cost	(1,003,524)	(549,522)
B	**Assumptions** (See Appendix A for interim measurements, if any)		
1	Discount rate		
	• Utilities	5.05%	6.05%
	• CPG	5.05%	6.02%
	• PNG	5.21%	6.13%
2	Expected long-term rate of return on plan assets	5.25%	5.25%
3	Census date	10/1/2024	10/1/2023
C	**Fair Value of Assets at Beginning of Year**	22,154,498	17,556,345
D	**Cash Flows Net of Medicare Part D Subsidy**	**Expected**	**Actual**
1	Employer contributions	0	0
2	Plan participants' contributions	14,829	8,939
3	Benefits paid from Company assets	0	0
4	Benefits paid from plan assets	541,167	317,721
E	**Amortization Period**	N/A	N/A

2.6 ASC 965 (plan reporting) information

All monetary amounts shown in US Dollars

			Utilities	Holding Company	Enterprises	UGI Plan Subtotal	CPG	PNG	Total
A	**Present Value of Benefit Obligations and Funded Status**								
	1	Present value of benefit obligations							
		a Participants currently receiving benefits	5,783,386	822,528	32,822	6,638,736	903,485	552,168	8,094,389
		b Other fully eligible participants	1,531,830	93,040	0	1,624,870	271,406	225,362	2,121,638
		c Other participants	411,992	8,093	0	420,085	90,719	103,923	614,727
		d Total	7,727,208	923,661	32,822	8,683,691	1,265,610	881,453	10,830,754
	2	Fair value of assets	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498
B	**Changes in Benefit Obligations**								
	1	Postretirement Benefit Obligation							
		a Amount as of October 1, 2023				7,607,355	1,097,463	745,023	9,449,841
		b Benefits earned				53,586	10,957	3,907	68,450
		c Benefits reclassified to amounts currently payable				(234,340)	(65,396)	(9,046)	(308,782)
		d Interest				450,512	64,891	45,354	560,757
		e Plan amendment effects				0	0	0	0
		f Change in actuarial assumptions				1,028,098	158,801	123,480	1,310,379
		g Actuarial (gains) losses				(221,520)	(1,106)	(27,265)	(249,891)
		h Total change in reserve				1,076,336	168,147	136,430	1,380,913
		i Amount as of October 1, 2024				8,683,691	1,265,610	881,453	10,830,754
	2	Total Obligation							
		a Amount as of October 1, 2023				7,607,355	1,097,463	745,023	9,449,841
		b Increase (decrease) in reserve				1,076,336	168,147	136,430	1,380,913
		c Amount as of October 1, 2024				8,683,691	1,265,610	881,453	10,830,754
C	**Change in Plan Assets**								
		1 Plan assets at October 1, 2023				13,680,961	2,230,653	1,644,731	17,556,345
		2 Investment return, net of taxes[1]				3,830,917	615,557	460,461	4,906,935
		3 Employer contributions				0	0	0	0
		4 Plan participants' contributions				0	8,939	0	8,939
		5 Benefits paid				(234,340)	(74,335)	(9,046)	(317,721)
		6 Plan assets at October 1, 2024				17,277,538	2,780,814	2,096,146	22,154,498

Actuarial assumptions and methods

The key actuarial assumptions used for plan reporting calculations are the same as those used to determine the postretirement welfare cost and are shown in the Actuarial Assumptions and Methods section.

[1] Return allocated based on percentage of total assets as of beginning of year

2.7 Maximum Deductible Employer Contributions

All monetary amounts shown in US Dollars

		Medical	Life	Total
A	**Maximum Deductible Employer Contribution**			
1	Qualified direct costs	133,820	220,904	354,724
2	Permitted addition to qualified asset account	0	829,225	829,225
3	Investment income (Limited to 1+2)	(133,820)	(319,696)	(453,516)
4	Participant contributions	0	0	0
5	Maximum deduction	0	730,433	730,433
6	Carryover contributions	0	0	0
7	Maximum deductible employer contribution *	0	730,433	730,433

Willis Towers Watson does not provide legal advice or tax advice. Accordingly, we recommend that the plan sponsor review with tax counsel the tax-deductibility of all contributions as Willis Towers Watson does not provide legal or tax advice.

* Amount that could be deducted if contribution had been made

2.8 Detailed Results for Employer Contributions - VEBA

All monetary amounts shown in US Dollars

			Medical	Life	Total
A	**Normal Cost, Liabilities and Funded Position**				
1	Actuarial accrued liability [AAL][1]		322,008	6,964,712	7,286,720
2	Assets				
	a	Market value	20,115,248	2,221,234	22,336,482
	b	Unrecognized investment losses (gains)	0	0	0
	c	Actuarial value [AV]	20,115,248	2,221,234	22,336,482
3	Funded Position				
	a	Unfunded actuarial accrued liability [AAL – AV]	(19,793,240)	4,743,478	(15,049,762)
	b	AAL funded percentage [AV ÷ AAL]	6,246.8%	31.9%	306.5%
B	**Key Economic Assumptions**				
1	Discount rate for normal cost and AAL				
	a	Pre-tax	7.50%	7.50%	
	b	Post-tax	5.25%	7.50%	
2	Salary increase rate		N/A	3.25%	
C	**Market value of assets for employer contributions:**				
1	As of January 1, 2024		17,058,068	2,122,442	19,180,510
2	Employer contributions		0	0	0
3	Participant contributions		0	0	0
4	Disbursements		(97,998)	(175,780)	(273,778)
5	Investment return (net of expenses)		3,155,178	274,572	3,429,750
6	As of January 1, 2025		20,115,248	2,221,234	22,336,482
7	Rate of return				18.0 %
D	**Actuarial value assets for employer contributions:**				
1	As of January 1, 2024				19,180,510
2	As of January 1, 2025				22,336,482
3	Rate of return				18.0 %

[1] Includes VEBA payable benefits from UGI Utilities, CPG, and PNG

Appendix A : Statement of consolidated actuarial assumptions, methods and data sources

Actuarial Assumptions and Methods — Postretirement Welfare Cost and Funding/Tax Deductions

Economic Assumptions

	Postretirement Welfare Cost	VEBA Contributions
Discount rate		
UGI Utilities	5.05%	N/A
CPG	5.05%	N/A
PNG	5.21%	N/A
After-tax - Medical	N/A	5.25%
After-tax – Life Insurance	N/A	7.50%
After-tax rate of return on assets		
Medical	5.25%	N/A
Life	7.50%	N/A
Average salary increase rate from age 40	3.25%	3.25%

Participation Assumptions

- **Participation rates**:

		Employee	*Dependent*
– Active employees	Medical	N/A	N/A
	Life insurance	100%	N/A

- – Retirees: Based on valuation census data
- **Percent married**: 70%
- **Spouse age**: Wife three years younger than husband

Demographic Assumptions

Postretirement welfare cost:

- Mortality: Pri-2012 blue collar table with rates decreased by 4.5%, projected Scale MP-2021 on a generational basis from 2012
- Disability: None assumed
- Termination: Rates varying by age

Age	*Rate*
25	8.50%
40	3.45%
55	0.00%

- Retirement: Rates varying by age

Age	*Rate*
55	2.0%
56	2.5%
57	3.0%
58	3.5%
59	4.0%
60	6.0%
61	5.0%
62	20.0%
63	20.0%
64	20.0%
65	40.0%
66	40.0%
67	40.0%
68	40.0%
69	40.0%
70	100.0%

- Covered pay: Rate of pay as of valuation date, plus commissions paid during the prior plan year and bonuses paid in December of the current plan year
- Administrative expenses: GAAP: N/A

  VEBA: 2% of paid benefits

Methods

Postretirement welfare cost:

• Measurement date	Fiscal year-end
• Service cost and APBO	Projected unit credit actuarial cost method, allocated from the date of hire to full eligibility date
• Market-related value of assets	Fair value
• Amortization of prior service cost/(credit)	Amortization of net prior service cost/(credit) resulting from a plan change is included as a component of Net Periodic Postretirement Benefit Cost/(Income) in the year first recognized and every year thereafter until such time as it is fully amortized. The annual amortization payment is determined in the first year as the increase in Accumulated Postretirement Benefit Obligation due to the plan change divided by the average remaining service period to full eligibility for participating employees expected to receive benefits under the plans. However, when the plan change reduces the Accumulated Postretirement Benefit Obligation, existing positive prior service costs are reduced or eliminated before a new prior service credit base is established.
• Amortization of net loss (gain)	Amortization of the net gain or loss resulting from experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of Net Periodic Postretirement Benefit Cost/(Income) for a year. If, as of the beginning of the year, that net gain or loss exceeds 10% of the greater of the projected benefit obligation and the market-related value of plan assets, the amortization is that excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.
• Benefits not valued	All benefits described in the Plan Provisions section of this report were valued. Willis Towers Watson has reviewed the plan provisions with the Company and, based on that review, is not aware of any other significant benefits required to be valued that were not.
• Valuation date for funding	First day of plan year. Key employees are excluded from this calculation, as are life insurance benefits in excess of $50,000.
• Actuarial funding liability	Aggregate cost method
• Actuarial value of assets:	Market value

Data Sources

UGI Utilities, Inc. furnished the participant data as of October 1, 2024. Data were reviewed for reasonableness and consistency, but no audit was performed. Based on discussions with the plan sponsor, assumptions or estimates were made when data was not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Change in Assumptions and Methods Since Prior Valuation

The discount rate for benefit obligations was changed from 6.05% to 5.05% for Utilities, 6.02% to 5.05% for CPG, and 6.13% to 5.21% for PNG.

Assumptions Rationale - Significant Economic Assumptions

Discount rate	As required by U.S. GAAP the discount rate was chosen by the plan sponsor based on market information on the measurement date. To accomplish this, the plan sponsor used a tool named BOND:Link which constructs a hypothetical yield curve based on yields available high quality corporate bonds as of the measurement date.
Annual rates of increase in compensation	Assumed increases were chosen by the plan sponsor and, as required by U.S. GAAP they represent an estimate of future experience.
Expected return on plan assets	We understand that the expected return on assets assumption reflects the plan sponsor's estimate of future experience for trust asset returns, reflecting the plan's current asset allocation and any expected changes during the current plan year, current market conditions and the plan sponsor's expectations for future market conditions. The analysis was informed by analysis of historical data, economists' forecasts and recent trends for CPI, GDP growth, and real returns on the various classes of assets held by the trust.

Assumptions Rationale - Significant Demographic Assumptions

Healthy Mortality	Assumption was selected by the plan sponsor and, as required by U.S. GAAP represents a best estimate of future experience, partially based on, based on a review of actual retiree experience from 2015-2019 conducted in 2020.
Termination	Termination rates were selected by the plan sponsor and, as required by U.S. GAAP represents a best estimate of future experience, based on a review of actual plan experience from 2015-2019 conducted in 2020.
Retirement	Retirement rates were selected by the plan sponsor and, as required by U.S. GAAP represents a best estimate of future experience, based on a review of actual plan experience from 2015-2019 conducted in 2020.

Model Descriptions and Disclosures (in accordance with ASOP No. 56)

Quantify

Quantify is the Willis Towers Watson centrally developed, tested and maintained Global actuarial valuation system. It is used to perform valuations of clients' benefit plans.

Quantify provides the ability to process data, calculate benefits and value benefit liabilities, develop results using applicable standards, and generate client reports.

Quantify parameters provide significant flexibility to model populations and plan designs. Various demographic, economic and benefit related assumptions exist for users to model multiple demographic and economic situations.

Plan liabilities are calculated based on standard actuarial techniques, developing actuarially reasonable results using the population and parameters entered. The calculation and presentation of liabilities in Quantify relies on the assumptions used and the reasonability of the assumptions selected.

Quantify incorporates standard liability methodologies that are intended to reasonably reflect a variety of economic or demographic conditions. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence.

Quantify is designed specifically for these purposes, and we know of no material limitations that would prevent the system from being suitable for these intended purposes. The actuaries signing this report have relied on the actuaries who develop, test and maintain this system, and have also performed a limited review of results to ensure that system parameters have been set appropriately and plan provisions coded correctly.

Quantify FR	Quantify Financial Reporting (FR) is intended to calculate funding results, accounting results and produce the associated client reports under selected accounting standards. The calculations and reports are based on various user specified inputs including liability results and asset values. Quantify FR develops valuation results for various accounting and funding purposes using standard actuarial techniques. Calculation of disclosure liabilities and results are based on roll forward liabilities. Liability roll-forwards are used in accounting scenarios where the date as of which liabilities are valued does not coincide with the fiscal year measurement date. The roll-forwards consist of adjusting liabilities for the passage of time.
Bond:Link	U.S. **BOND:Link** is a methodology to assist with the selection of discount rates used in liability and cost measurements related to employee benefit plans. Discount rates are derived by identifying a theoretical settlement portfolio of high-quality corporate bonds sufficient to provide for a plan's projected benefit payments. The single interest rate is then determined that results in a discounted value of the plan's benefit payments that equals the market value of the selected bond portfolio. Updated BOND:Link models are developed monthly as of the last day of the month. The construction of a BOND:Link model relies on bond data collected as of the measurement date Parameters provide the user the ability to control aspects of the model. The model output allows the user to see the effect of those parameters. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P.
Published Demographic Tables	Certain demographic tables described above are standard published tables or are based on standard published tables from models developed by organizations with the requisite expertise

Appendix B : Summary of principal other postretirement benefit plan provisions

UGI Utilities Plan

Medical Benefits	
Eligibility	Retired prior to January 1, 1989 or, as of January 1, 1989, age 55 with 10 years of service or a combination of age and service equal to 80.
Service	Years and months of service as a covered employee.
Dependent eligibility	Spouse and unmarried children under age 19 or a full-time student under age 23.
Survivor eligibility	Eligibility continues beyond death of retiree or active employee eligible to retire.
Under age 65 benefits	N/A
Age 65 and older benefits	Healthcare reimbursement account (HRA) for covered retirees in the amount of $500 per year for participants retired after 1986 and $700 per year for those retiring before 1987
Postretirement Contributions	
■ Pre-65	N/A
■ Post-65	N/A

Life Insurance Benefits	
Eligibility	Pension eligible employees retiring after age 55 with 10 years of service.
Postretirement contributions	None
Benefits	25% of pay at retirement with a maximum coverage amount of $50,000 If retired prior to January 1, 1989 or, as of January 1, 1989, age 55 with 10 years of service or a combination of age and service equal to 80: One times pay at retirement, reducing 15% for the first four years and 2.5% for the fifth year after retirement to an ultimate level of 37.5%; alternatively, may elect a flat $20,000 non-reducing benefit.

Changes in Benefits Valued Since Prior Year

There have been no changes in the benefits valued since the prior valuation.

Central Penn Gas

Medical Benefits

Covered Employees	**Nonunion** – **North Participants** Retired prior to January 1, 2009 **Nonunion** – **South Participants** **Access only -**no subsidized benefits **Union** – **North Participants** Hired prior to 1/1/2004 and retired prior to age 55 with 10 years of service **Union** – **South Participants** **Access only -**no subsidized benefits
Service	Years and months of service as a covered employee.
Dependent eligibility	Spouse and unmarried children under age 19 or a full-time student under age 23.
Survivor eligibility	Eligibility continues beyond death of retiree or active employee eligible to retire.
Under age 65 benefits	Aetna's Choice POS II plan.
Age 65 and older benefits	Healthcare reimbursement account (HRA) for covered retirees in the amount of $500 per year for participants retired after 1986 and $700 per year for those retiring before 1987
Base Postretirement Contributions	Pre-65: Aetna Choice POS II None Post-65: N/A
Annual defined dollar benefit	Pre-65: the cap levels are identified as $4,300 per person (retiree and dependent). The actual maximum employer subsidy is equal to the specified cap level minus the applicable Base Postretirement Contribution. Post-65: N/A

Life Insurance Benefits

Eligibility	Pension eligible employees retiring after age 55 with 10 years of service
Postretirement contributions	None
Benefits	25% of pay at retirement with maximum coverage of $50,000

Future Plan Changes

No future plan changes were recognized in determining postretirement welfare cost.

Changes in Benefits Valued Since Prior Year

There have been no changes in the benefits valued since the prior valuation.

Penn Natural Gas

Life Insurance Benefits

Eligibility	UGI pension eligible employees who had not attained full eligibility for benefits as of the date UGI acquired PNG and who retire after attaining age 55 with 10 years of service.
Postretirement contributions	None
Benefits	25% of pay at retirement with a maximum coverage amount of $50,000.

Changes in Benefits Valued

There have been no changes in the benefits valued since the prior valuation.

Appendix C : Accounting exhibits by plan

C.1 Summary of key results for period beginning October 1, 2024

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
Benefit Cost/(Income)	Net Periodic Postretirement Benefit Cost/(Income)	(801,363)	20,589	(692)	(781,466)	(136,864)	(85,194)	(1,003,524)
	Benefit Cost/(Income) due to Special Events	0	0	0	0	0	0	0
	Total Benefit Cost/(Income)	(801,363)	20,589	(692)	(781,466)	(136,864)	(85,194)	(1,003,524)
Plan Assets	Fair Value of Plan Assets (FVA)	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498
	Return on Fair Value of Plan Assets during Prior Year	28.2%	28.8%	0.0%	28.2%	28.1%	28.0%	28.2%
Benefit Obligations	Accumulated Postretirement Benefit Obligation (APBO)	(7,727,208)	(923,661)	(32,822)	(8,683,691)	(881,453)	(1,265,610)	(10,830,754)
Funded Ratio	Fair Value of Plan Assets to APBO	217.3%	52.3%	0.0%	199.0%	237.8%	219.7%	204.5%
Accumulated Other Comprehensive (Income)/Loss (Pre-tax)	Net Prior Service Cost/(Credit)	0	0	0	0	0	(16,862)	(16,862)
	Net Loss/(Gain)	(4,776,701)	(110,198)	(28,642)	(4,915,541)	(859,202)	57,905	(5,716,838)
	Total Accumulated Other Comprehensive (Income)/Loss	(4,776,701)	(110,198)	(28,642)	(4,915,541)	(859,202)	41,043	(5,733,700)

UGI Utilities, Inc. Consolidated Postretirement Welfare Plans

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
Assumptions	Discount Rate	5.05%	5.05%	5.05%	5.05%	5.21%	5.05%	
	Expected Long-Term Rate of Return on Plan Assets	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	
	Current Health Care Cost Trend Rate	N/A	N/A	N/A	N/A	N/A	N/A	
	Ultimate Health Care Cost Trend Rate	N/A	N/A	N/A	N/A	N/A	N/A	
	Year of Ultimate Trend Rate	N/A	N/A	N/A	N/A	N/A	N/A	
Participant Data	Census Date	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	

C.2 Participant information

All monetary amounts shown in US Dollars

			UGI Utilities	CPG	PNG
A	**Active and Deferred Employees**				
	1	Number	342	82	60
	2	Total annual compensation/salary	38,225,110	6,553,927	5,276,682
	3	Average compensation/salary	111,769	79,926	87,945
	4	Average age	55.3	54.5	55.0
	5	Average credited service	28.1	24.8	26.4
B	**Currently Receiving Benefits**				
	1	Medical retirees:			
		a Number under 65	0	0	0
		b Number 65 and older	21	38	0
		c Total	21	38	0
		d Average age	90.0	83.7	N/A
	2	Medical surviving spouses and dependents:			
		a Number under 65	0	1	0
		b Number 65 and older	11	30	0
		c Total	11	31	0
		d Average age	88.9	79.8	N/A
	3	Life insurance retirees			
		a Number under 65	65	20	7
		b Number 65 and older	544	65	68
		c Total	609	85	75
		d Average age	73.4	68.7	69.2

C.3 Balance sheet asset/(liability) at October 1, 2024

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI PRW Subtotal	PNG	CPG	Total
A	**Development of Balance Sheet Asset/(Liability)**							
1	Accumulated postretirement benefit obligation (APBO)	(7,727,208)	(923,661)	(32,822)	(8,683,691)	(881,453)	(1,265,610)	(10,830,754)
2	Fair value of plan assets (FVA)	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498
3	Net balance sheet asset/(liability)	9,067,539	(440,870)	(32,822)	8,593,847	1,214,693	1,515,204	11,323,744
B	**Current and Noncurrent Classification**							
1	Noncurrent asset	N/A	N/A	N/A	8,593,847	1,214,693	1,515,204	11,323,744
2	Current liability	N/A	N/A	N/A	0	0	0	0
3	Noncurrent liability	N/A	N/A	N/A	0	0	0	0
4	Net balance sheet asset/(liability)	N/A	N/A	N/A	8,593,847	1,214,693	1,515,204	11,323,744
C	**Accumulated Other Comprehensive (Income)/Loss**							
1	Net prior service cost/(credit)	0	0	0	0	0	(16,862)	(16,862)
2	Net loss/(gain)	(4,776,701)	(110,198)	(28,642)	(4,915,541)	(859,202)	57,905	(5,716,838)
3	Accumulated other comprehensive (income)/loss	(4,776,701)	(110,198)	(28,642)	(4,915,541)	(859,202)	41,043	(5,733,700)
D	**Assumptions and Dates**							
1	Discount rate	5.05%	5.05%	5.05%	5.05%	5.21%	5.05%	
2	Current health care cost trend rate	N/A	N/A	N/A	N/A	N/A	N/A	
3	Ultimate health care cost trend rate	N/A	N/A	N/A	N/A	N/A	N/A	
4	Year ultimate trend rate is reached	N/A	N/A	N/A	N/A	N/A	N/A	
5	Census date	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	

C.4 Changes in liabilities and assets for period beginning October 1, 2024

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
A	**Change in Accumulated Postretirement Benefit Obligation (APBO)**							
1	APBO at beginning of prior fiscal year	6,749,956	828,730	28,669	7,607,355	745,023	1,097,463	9,449,841
2	Employer service cost	50,877	2,709	0	53,586	3,907	10,957	68,450
3	Interest cost	399,882	48,943	1,687	450,512	45,354	64,891	560,757
4	Actuarial loss/(gain)	737,637	65,698	3,243	806,578	96,215	157,695	1,060,488
5	Plan participants' contributions	0	0	0	0	0	8,939	8,939
6	Benefits paid from plan assets	(211,144)	(22,419)	(777)	(234,340)	(9,046)	(74,335)	(317,721)
7	Benefits paid from Company assets	0	0	0	0	0	0	0
8	Medicare Part D subsidy	0	0	0	0	0	0	0
9	Administrative expenses paid	0	0	0	0	0	0	0
10	Plan amendments	0	0	0	0	0	0	0
11	Acquisitions/(divestitures)	0	0	0	0	0	0	0
12	Curtailments	0	0	0	0	0	0	0
13	Settlements	0	0	0	0	0	0	0
14	Special/contractual termination benefits	0	0	0	0	0	0	0
15	APBO at beginning of current fiscal year	7,727,208	923,661	32,822	8,638,691	881,453	1,265,610	10,830,754
B	**Change in Plan Assets**							
1	Fair value of plan assets at beginning of prior fiscal year	13,286,254	394,707	0	13,680,961	1,644,731	2,230,653	17,556,345
2	Actual return on plan assets	3,719,637	110,503	777	3,830,917	460,461	615,557	4,906,935
3	Employer contributions	0	0	0	0	0	0	0
4	Plan participants' contributions	0	0	0	0	0	8,939	8,939
5	Benefits paid	(211,144)	(22,419)	(777)	(234,340)	(9,046)	(74,335)	(317,721)
6	Administrative expenses paid	0	0	0	0	0	0	0
7	Acquisitions/(divestitures)	0	0	0	0	0	0	0
8	Settlements	0	0	0	0	0	0	0
9	Fair value of plan assets at beginning of current fiscal year	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498

C.5 Summary of net balances at October 1, 2024

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
	Amortization Details of Plan Amendment #1							
1	Measurement date established	N/A	N/A	N/A	N/A	N/A	10/01/2013	N/A
2	Original amount	N/A	N/A	N/A	N/A	N/A	(747,240)	N/A
3	Net amount at 10/01/2024	N/A	N/A	N/A	N/A	N/A	(16,862)	N/A
4	Remaining amortization period	N/A	N/A	N/A	N/A	N/A	0.25395	N/A
5	Amortization amount in 2025	N/A	N/A	N/A	N/A	N/A	16,862	N/A
6	Effect of curtailments	N/A	N/A	N/A	N/A	N/A	0	N/A
7	Other events	N/A	N/A	N/A	N/A	N/A	0	N/A
A	**Summary of Net Prior Service Cost/(Credit)**							
1	Net amount at 10/01/2024	0	0	0	0	0	(16,862)	(16,862)
2	Amortization amount during 2025	0	0	0	0	0	16,862	16,862
3	Plan amendments	0	0	0	0	0	0	0
4	Effect of curtailments	0	0	0	0	0	0	0
5	Other events	0	0	0	0	0	0	0
B	**Summary of Net Loss/(Gain)**							
1	Net amount at 10/01/2024	(4,776,701)	(110,198)	(28,642)	(4,915,541)	(859,202)	57,905	(5,716,838)
2	Amount recognized during 2025	371,781	3,110	2,306	377,197	77,390	0	454,587
3	Effect of curtailments	0	0	0	0	0	0	0
4	Effect of settlements	0	0	0	0	0	0	0
5	Other events	0	0	0	0	0	0	0

C.6 Development of plan assets for benefit cost

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
A	**Reconciliation of Fair Value of Plan Assets**							
1	Fair value of Plan assets at 09/30/2023	13,286,254	394,707	0	13,680,961	1,644,731	2,230,653	17,556,345
2	Investment return	3,719,637	110,503	777	3,830,917	460,461	615,557	4,906,935
3	Employer contributions	0	0	0	0	0	0	0
4	Plan participants' contributions	0	0	0	0	0	8,939	8,939
5	Benefits paid	(211,144)	(22,419)	(777)	(234,340)	(9,046)	(74,335)	(317,721)
6	Administrative expenses paid	0	0	0	0	0	0	0
7	Acquisitions/(divestitures)	0	0	0	0	0	0	0
8	Settlements	0	0	0	0	0	0	0
9	Fair value of Plan assets at 09/30/2024	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498
B	**Reconciliation of Market Related Value of Assets**							
1	Market related value of plan assets at 09/30/2023	13,286,254	394,707	0	13,680,961	1,644,731	2,230,653	17,556,345
2	Actual return on plan assets	3,719,637	110,503	777	3,830,917	460,461	615,557	4,906,935
3	Employer contributions	0	0	0	0	0	0	0
4	Plan participants' contributions	0	0	0	0	0	8,939	8,939
5	Benefits paid	(211,144)	(22,419)	(777)	(234,340)	(9,046)	(74,335)	(317,721)
6	Administrative expenses paid	0	0	0	0	0	0	0
7	Acquisitions/(divestitures)	0	0	0	0	0	0	0
8	Settlements	0	0	0	0	0	0	0
9	Market related value of plan assets at 09/30/2024	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498
C	**Rate of Return on Invested Assets**							
1	Weighted invested assets	13,180,682	383,497	(389)	13,563,790	1,640,208	2,197,955	17,401,953
2	Rate of return	28.2%	28.8%	0.0%	28.2%	28.1%	28.0%	28.2%

UGI Utilities, Inc. Consolidated Postretirement Welfare Plans

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		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
D	**Investment Loss/(Gain)**							
1	Actual return	3,719,637	110,503	777	3,830,917	460,461	615,557	4,906,935
2	Expected return	687,429	19,541	0	706,970	85,872	115,505	908,347
3	Loss/(gain)	(3,032,208)	(90,962)	(777)	(3,123,947)	(374,589)	(500,052)	(3,998,588)

C.7 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
A	**Total Benefit Cost for Fiscal Year Ending 09/30/2025**							
1	Employer service cost	58,536	2,239	0	60,775	4,415	13,029	78,219
2	Interest cost	383,422	45,514	1,614	430,550	45,605	63,022	539,177
3	Expected return on plan assets	(871,540)	(24,054)	0	(895,594)	(109,494)	(144,383)	(1,149,471)
4	Subtotal	(429,582)	23,699	1,614	(404,269)	(59,474)	(68,332)	(532,075)
5	Net prior service cost/(credit) amortization	0	0	0	0	0	(16,862)	(16,862)
6	Net loss/(gain) amortization	(371,781)	(3,110)	(2,306)	(377,197)	(77,390)	0	(454,587)
7	Subtotal	(371,781)	(3,110)	(2,306)	(377,197)	(77,390)	(16,862)	(471,449)
8	Net periodic postretirement benefit cost/(income)	(801,363)	20,589	(692)	(781,46)	(136,864)	(85,194)	(1,003,524)
9	Curtailment (gain)/loss	0	0	0	0	0	0	0
10	Settlement (gain)/loss	0	0	0	0	0	0	0
11	Special/contractual termination benefits	0	0	0	0	0	0	0
12	Total benefit cost	(801,363)	20,589	(692)	(781,466)	(136,864)	(85,194)	(1,003,524)
B	**Assumptions**							
1	Discount rate	5.05%	5.05%	5.05%	5.05%	5.21%	5.05%	
2	Expected long-term rate of return on plan assets	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	
3	Current health care cost trend rate	N/A	N/A	N/A	N/A	N/A	N/A	
4	Ultimate health care cost trend rate	N/A	N/A	N/A	N/A	N/A	N/A	
5	Year ultimate trend rate is reached	N/A	N/A	N/A	N/A	N/A	N/A	
6	Census date	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	10/01/2024	
C	**Fair Value of Assets at Beginning of Year**	16,794,747	482,791	0	17,277,538	2,096,146	2,780,814	22,154,498

UGI Utilities, Inc. Consolidated Postretirement Welfare Plans

		Utilities	Holding Company	Enterprises	UGI Plan Subtotal	PNG	CPG	Total
D	**Cash Flows Net of Medicare Part D Subsidy**							
1	Expected							
a	Employer contributions	0	0	0	0	0	0	0
b	Plan participants' contributions	0	0	0	0	0	14,829	14,829
c	Benefits paid from Company assets	0	0	0	0	0	0	0
d	Benefits paid from plan assets	391,258	49,892	1,733	443,883	21,350	76,934	541,167
2	Actual							
a	Employer contributions	0	0	0	0	0	0	0
b	Plan participants' contributions	0	0	0	0	0	8,939	8,939
c	Benefits paid from Company assets	0	0	0	0	0	0	0
d	Benefits paid from plan assets	211,144	22,419	777	234,340	9,046	74,335	317,721
E	**Amortization Period**							
1	For gain/loss amortization, if applicable	8.33077	5.73310	10.99510	N/A	8.39363	8.69254	N/A
2	For new prior service cost bases, if any	8.06798	8.13862	10.99510	N/A	5.57308	8.39212	N/A

SDR-RR-39

Request:

Please reconcile the historical and future test year SFAS No. 106 expense levels with the amount identified in the actuarial report.

Response:

Please see Attachment SDR-RR-39.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Schedule of SFAS No. 106 Expenses

		HTY 9/30/2025	FTY 9/30/2026	FPFTY 9/30/2027
Amortization of Regulatory Liability		$ (974,464)	$ (974,464)	$ -
Actual/Budget Year Expense/(Income)		(895,457)	(880,627)	(1,855,091)
Total Actual/Budget Year Expense/(Income)		$ (1,869,921)	$ (1,855,091)	$ (1,855,091)
Actuarial Expense (Income)		$ (910,742)	$ (1,329,511)	N/A
Difference		$ (959,179)	$ (525,580)	
Reconciling Items:				
Amortization of Regulatory Liability	(1)	$ (974,464)	$ (974,464)	
Actual/Budget Year Expense/(Income)	(2)	15,285	448,884	
		$ 959,179	$ 525,580	

(1) HTY and FTY expense/(income) includes $974,464 per year of amortization expense for a regulatory liability associated with the over recovery of SFAS 106 costs, which is not part of the actuarial expense (income).

(2) The reconciling items are the result of the true-up entry at year end and the annual budget (based on an estimate) being performed before the actuarial report totals for the year were available.

SDR-RR-40

Request:

Please identify the actual or projected amounts contributed to SFAS No. 106 funds for the historic and future test years. Identify the actual or projected dates and amounts of the contributions.

Response:

There are no actual or projected SFAS 106 contributions included in the historic, future or fully projected future test years.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-41

Request:

Please explain the funding options or plans which are being used for SFAS No. 106 costs. Identify the portion of the costs which are eligible for tax preferred funding.

Response:

All of the SFAS No. 106 (post-employment plan) costs are funded assets which are held in a tax advantaged VEBA trust.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-42

Request:

Is the Company studying and/or anticipating any changes to its postretirement benefits offered to employees as a result of SFAS No. 106 or for other reasons? If yes, please provide such study and/or explain the anticipated change.

Response:

The Company is not studying or anticipating any changes to its postretirement benefits offered to employees.

Prepared by or under the supervision of: Amy M. Keller

SDR-RR-43

Request:

Please state whether the Company has included expenses related to SFAS No. 112 in its test year claim. If so, please provide complete details and include a copy of the actuarial study.

Response:

The Company has included expenses related to SFAS No. 112 in its test year claim. However, in accordance with HIPAA guidelines, UGI Gas does not record or track these additional expenses separately from active employee benefit costs. For this reason, UGI Gas does not have the ability to calculate this additional post-employment benefit expense.

The Fiscal Year 2025 expenses were based on the actuarial study as of 9/30/2024. The Company's most recent SFAS 112 actuarial study will be used to support expense in Fiscal Year 2026. Refer to Attachment SDR-RR-43 for a copy of the report issued as a result of this study.

Prepared by or under the supervision of: Amy M. Keller

October 7, 2025

[redacted]
Senior Accountant, Financial Reporting
UGI Corporation [redacted]
Irwin Building
460 N. Gulph Road
King of Prussia, PA 19406

Dear [redacted]:

UGI ASC 712 VALUATION RESULTS AS OF SEPTEMBER 30, 2025

The purpose of this letter is to provide you with the estimated ASC 712 (formerly FAS 112) obligations for UGI Utilities and Penn Natural Gas (PNG) group as of September 30, 2025. Consistent with the September 30, 2024 results, the UGI Utilities results contain the obligations attributable to Central Penn Gas (CPG) participants as well. **New for September 30, 2025, the figures summarized herein incorporate Mountaineer Gas Company (MGC) employees; it is our understanding that MGC's STD coverage is being merged with UGI's on January 1, 2026.**

Valuation Results

Below is a summary of the estimated ASC 712 obligations as of September 30, 2025 for UGI's short-term disability (STD) income benefit and COBRA continuation of health coverage (long-term disability income, medical and life insurance continuation are estimated by UGI and are not included with the results presented in this letter). In addition, the ASC 712 obligations for PNG and MGC are provided for the STD income benefit. Each of the obligations was developed according to the standards of ASC 712 (formerly FAS 112, 5 and 43). For comparative purposes the individual plan obligations are shown relative to September 30, 2024 results.

Philadelphia Consulting Office
1900 Market Street, 8th Floor
Philadelphia, PA 19103-7501

T +1 215 246 7800
F 1 215 246 6251
W wtwco.com

Willis Towers Watson US LLC

[redacted]
October 7, 2025

	Obligation as of					
	September 30, 2025			September 30, 2024		
Benefit	**Current**	**Non-Current**	**Total**	**Current**	**Non-Current**	**Total**
STD income (UGI+CPG+PNG+MGC)	$1,469,000	$221,000	$1,690,000	$1,128,000	$500,000	$1,628,000
COBRA	296,000	0	296,000	275,000	0	275,000
Total	1,765,000	221,000	1,986,000	1,403,000	500,000	1,903,000

Please note the following regarding this year's valuation results:

Short-term Disability Income Continuation

The UGI+CPG+PNG+MGC obligation for the STD income benefit as of September 30, 2025 is $1,690,000 using a 5.62% discount rate for UGI+CPG+PNG and 5.63% discount rate for MGC; this compares to $1,628,000 as of September 30, 2024 using a 5.05% discount rate.

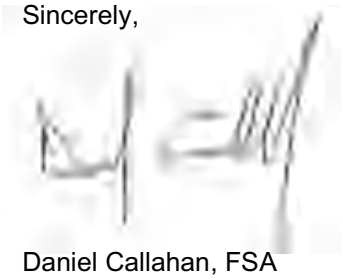
The liability amount represents the obligation for the STD income benefit to which employees are entitled as years of active service increase. The valuation reflects the costs associated with all future disabilities expected to occur after September 30, 2025. The rates of incidence and duration of STD claims are based on a blend of standard actuarial assumptions and actual experience received from UGI, CPG, PNG and MGC.

COBRA Continuation of Health Coverage

This amount represents UGI's obligation for the additional medical expense anticipated from COBRA participants above the 102% of premium UGI collects from COBRA beneficiaries. The projected cost of health coverage is based on UGI's average 2025 cost of providing these benefits for COBRA participants.

[redacted], if you have any questions or need further information, please call us.

Sincerely,



Daniel Callahan, FSA
Direct Dial: 215-246-7336

[redacted]

Ryan Holden, FSA, EA
Direct Dial: 215-246-6231

cc: [redacted]

[redacted]
October 7, 2025

September 30, 2025 ASC 712 Methods and Assumptions – UGI+CPG+PNG+MGC

Short-term Disability Income Continuation

UGI+CPG+PNG+MGC

Methods and Assumptions

Discount Rate	5.62% (UGI+CPG+PNG); 5.63% (MGC)	
Incidence of disability	5.3%	
Average duration of disability	7.0 Weeks	
Accounting method	Former FAS 43	
Benefit schedule	Weeks at 100%	Weeks at 50%
Service (years)		
Less than 1	4	0
1 less than 10	8	18
10 less than 15	12	14
15 less than 20	17	9
20+	26	0
Average age	45.0	
Average years of service	11.7	
Percent male	71%	
Average salary	$99,133	
Headcount	2,754	

[redacted]
October 7, 2025

COBRA

UGI+CPG

Methods and Assumptions

Discount Rate	5.62%
Accounting method	Former FAS 5
Average age	54.7
Percent male	55%
Expected utilization	150% of average
Headcount	44
Average monthly rate	$1,461

[redacted]
October 7, 2025

Information Related to Actuarial Standard of Practice No. 56

AGEDIST

AgeDist is a spreadsheet tool that applies relative cost factors by age to average per capita costs (pre and post 65) and census weights to produce age-graded plan costs for pre- and post-65 populations. The average per capita costs and census weights are provided as inputs to the tool which is then combined with a morbidity curve to produce a set of weighted average age-related costs that equal the average. The age-graded costs are used in the actuarial valuation.

The morbidity curve was developed from a broad set of claims data aggregated by age and blended and may not reflect your specific morbidity. The model does not evaluate the average per capita costs or census weights for reasonableness or consistency.

The model(s) used for this analysis is designed specifically for these purposes, and we know of no material limitations that would prevent the model(s) from being suitable for these intended purposes.

We are not aware of any material inconsistencies among assumptions used in this work. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence. The calculation and presentation of results relies on the assumptions used and the reasonability of the assumptions selected. The output of the model(s) used in this analysis are considered reasonable based on the aggregation of assumptions used. However, a different set of results could also be considered reasonable based on a range of possible values used for each assumption.

The individuals signing or delivering this report have relied on other WTW employees and actuaries who develop, test and maintain each of the proprietary models used for this analysis and have also performed a basic review of assumptions and results to ensure that the models have been set up appropriately and coded correctly. We have not relied on any external experts to develop, review, or validate the model(s) used in this analysis

In preparing the results presented in this report, we have relied upon information provided to us regarding plan provisions, plan participants, participant contribution amounts and/or claims data. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this report is dependent upon the accuracy and completeness of the underlying information. We are aware of no errors or omissions that would have a significant effect on the results of our calculations.

[redacted]
October 7, 2025

Quantify

Quantify is the WTW centrally developed, tested and maintained Global actuarial valuation system. It is used to perform valuations of clients' benefit plans. Quantify provides the ability to process data, calculate benefits and value benefit liabilities, develop results using applicable standards, and generate client reports. Quantify parameters provide significant flexibility to model populations and plan designs. Various demographic, economic and benefit related assumptions exist for users to model multiple demographic and economic situations.

Plan liabilities are calculated based on standard actuarial techniques, developing actuarially reasonable results using the population and parameters entered the calculation and presentation of liabilities in Quantify relies on the assumptions used and the reasonability of the assumptions selected. Quantify incorporates standard liability methodologies that are intended to reasonably reflect a variety of economic or demographic conditions. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence.

Quantify is designed specifically for these purposes, and we know of no material limitations that would prevent the system from being suitable for these intended purposes. The actuaries signing this report have relied on the actuaries who develop, test and maintain this system, and have also performed a limited review of results to ensure that system parameters have been set appropriately and plan provisions coded correctly.

RATE:Link

RATE:Link is a methodology to develop spot rates to be used for measurements related to employee benefit plans. The same core methodology is used to develop all RATE:Link curves. The RATE:Link process develops term structures of interest rates from corporate bond data for each covered market. The construction of RATE:Link yield curves relies on bond data collected as of the measurement date. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P

[redacted]
October 7, 2025

Actuarial Certification

UGI retained WTW to perform a valuation of its postemployment benefit plans in order to determine its postemployment benefit cost in accordance with ASC 712 (formerly FAS 112). This valuation has been conducted in accordance with generally accepted actuarial principles and practices.

The consulting actuaries are members of the Society of Actuaries and other professional actuarial organizations and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to postemployment benefit plans.

In preparing the results presented in this report, we have relied upon information provided to us regarding plan provisions, plan participants, and plan costs. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this report is dependent upon the accuracy and completeness of the underlying information.

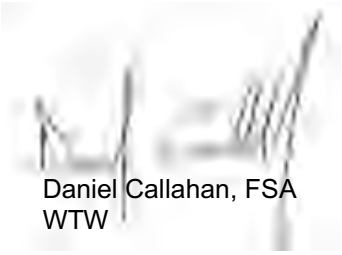
The actuarial assumptions and the accounting policies and methods employed in the development of the postemployment benefit cost have been selected by the plan sponsor. WTW has evaluated the assumptions used and believes that they do not significantly conflict with what would be reasonable. ASC 712 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this report are reasonable actuarial results. However, a different set of results could also be considered reasonable actuarial results, since the actuarial standards of practice describe a "best-estimate" range for each assumption, rather than a single best-estimate value. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

The information contained in this report was prepared for the internal use of UGI and its auditors in connection with our actuarial valuation of the postemployment benefit plans. It is neither intended nor necessarily suitable for other purposes. UGI may also distribute this actuarial valuation report to the appropriate authorities who have the legal right to require UGI to provide them with this report, in which case UGI will use best efforts to notify WTW of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without WTW's prior written consent.

[redacted]

Ryan Holden, FSA, EA
WTW



Daniel Callahan, FSA
WTW

SDR-RR-44

Request:

Please provide all documentation supporting the uncollectible accrual rate reflected in the Company's filing.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected Future), Schedule D-11, for a calculation of the uncollectible accrual rate.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-45

Request:

Please provide all work papers and documentation supporting the Company's claimed balance of gas stored underground - current. Include support for the monthly injections and withdrawals and the gas cost rate.

Response:

Please refer to Attachment SDR-RR-45.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
GAS STORED UNDERGROUND - CURRENT
SEPTEMBER 2024 - SEPTEMBER 2025

Month	Injections DTH	Withdrawals DTH	Inventory Change DTH	Inventory Balance DTH	Injected Value	Withdrawn Value	Monthly $ Change	Balance $ Value	Average Weighted Cost of Inventory $ per DTH
Beginning Balance				14,358,571				$ 23,854,852	
September 2024	2,708,372	(131,222)	2,577,150	16,935,721	$ 4,058,874	$ (236,962)	$ 3,821,912	$ 27,676,764	$ 1.6342
October 2024	2,766,004	(217,585)	2,548,419	19,484,140	$ 5,402,379	$ (410,186)	$ 4,992,193	$ 32,668,957	$ 1.6767
November 2024	294,198	(727,658)	(433,460)	19,050,680	$ 656,544	$ (1,284,377)	$ (627,833)	$ 32,041,123	$ 1.6819
December 2024	79,842	(4,177,888)	(4,098,046)	14,952,634	$ 243,170	$ (7,092,714)	$ (6,849,543)	$ 25,191,580	$ 1.6848
January 2025	1,375	(5,911,372)	(5,909,997)	9,042,637	$ 28,243	$ (9,885,917)	$ (9,857,674)	$ 15,333,906	$ 1.6957
February 2025	318,445	(4,279,912)	(3,961,467)	5,081,170	$ 969,383	$ (7,312,591)	$ (6,343,208)	$ 8,990,697	$ 1.7694
March 2025	65,494	(3,224,375)	(3,158,881)	1,922,289	$ 197,208	$ (5,495,859)	$ (5,298,651)	$ 3,692,046	$ 1.9207
April 2025	2,765,757	(446,661)	2,319,096	4,241,385	$ 8,620,277	$ (1,224,752)	$ 7,395,525	$ 11,087,571	$ 2.6141
May 2025	2,870,301	(238,679)	2,631,622	6,873,007	$ 6,827,980	$ (626,538)	$ 6,201,442	$ 17,289,014	$ 2.5155
June 2025	3,018,185	(111,918)	2,906,267	9,779,274	$ 7,139,857	$ (294,920)	$ 6,844,937	$ 24,133,951	$ 2.4679
July 2025	2,886,280	(290,011)	2,596,269	12,375,543	$ 7,364,577	$ (766,045)	$ 6,598,532	$ 30,732,483	$ 2.4833
August 2025	2,908,658	(239,831)	2,668,827	15,044,370	$ 6,747,899	$ (621,382)	$ 6,126,518	$ 36,859,000	$ 2.4500
September 2025	2,621,603	(224,304)	2,397,299	17,441,669	$ 5,617,126	$ (571,742)	$ 5,045,384	$ 41,904,384	$ 2.4025
							Sub Total:	$ 307,601,475	
							Number of Months:	13	
							Average Monthly Balance:	$ 23,661,652	

SDR-RR-46

Request:

Please provide a comparison between actual and budgeted O&M expenses by budget cost element for the historical test year and explain any budget variances of 10 percent or more.

Response:

Please see Attachment SDR-RR-46.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Actual versus Budgeted Cost Comparison
(thousands of dollars)

Comparison - Actual to Budget FY 2025

	Actual 2025	Budget 2025	Variance	% Variance
Cost of Sales (1)	415,177	377,795	(37,382)	(9.9%)
Maintenance and Other Operating Expenses	242,645	247,333	4,688	1.9%
Depreciation/Amortization	142,917	142,548	(369)	(0.3%)
Taxes Other than Income Taxes	12,660	13,138	477	3.6%
Total Operating Expenses	813,399	780,813	(32,586)	(4.17%)

Maintenance and Other Operating Expenses

	Actual 2025	Budget 2025	Variance	% Variance
Payroll and Employee Benefits	94,672	97,999	3,327	3.4%
Transportation	5,366	5,699	333	5.9%
Contracted Labor, Materials and Equipment	41,015	44,252	3,237	7.3%
Uncollectible Allowance	16,594	18,249	1,655	9.1%
Information Technology	18,700	20,222	1,522	7.5%
Other	66,299	60,912	(5,387)	(8.8%)
	242,645	247,333	4,688	1.9%

(1) Cost of Sales is shown net of Off System Sales and Capacity Release. These items are budgeted on a net basis in revenue. Actuals are posted on a gross basis in both revenue and cost of sales.

SDR-RR-47

Request:

Please provide the most recent actual number of eligible participants in each of the employee medical and dental plans reflected in the Company's filing.

Response:

Please see Attachment SDR-RR-47 for the most recent actual number of eligible participants in each of the employee medical and dental plans reflected in the Company's filing.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc – Gas Division

Enrolled Employees for Calendar 2026 (as of November 2025)

Medical – Blue Cross PPO Basic	
	Count as of 11/2025
Employee	28
Employee + Spouse	3
Employee + Child(ren)	5
Employee + Family	9
TOTAL	**45**

Dental – United Concordia Basic	
	Count as of 11/2025
Employee	301
Employee + Spouse	76
Employee + Child(ren)	65
Employee + Family	149
TOTAL	**591**

Medical – Blue Cross PPO Preferred	
	Count as of 11/2025
Employee	330
Employee + Spouse	100
Employee + Child(ren)	126
Employee + Family	134
TOTAL	**690**

Dental – United Concordia Buy Up	
	Count as of 11/2025
Employee	391
Employee + Spouse	134
Employee + Child(ren)	137
Employee + Family	177
TOTAL	**839**

Medical – Blue Cross HDHP	
	Count as of 11/2025
Employee	287
Employee + Spouse	74
Employee + Child(ren)	77
Employee + Family	155
TOTAL	**593**

Includes UGI Utilities, Inc employees who provide service to UGI Gas and those that provide service to both UGI Gas and UGI Electric

SDR-RR-48

Request:

Please provide workpapers showing the derivation of future test year Social Security and Medicare FICA taxes based on future test year labor expense. Identify both the total and O&M amounts.

Response:

Please refer to UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules D-31 and D-32.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-49

Request:

Please provide work papers showing the derivation of future test year federal and state unemployment taxes. Show both the total and O&M amounts.

Response:

Please refer to UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules D-31 and D-32.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-50

Request:

Please provide work papers showing the derivation of future test year capital stock taxes.

Response:

Not applicable. The PA Capital Stock tax was eliminated for tax years beginning January 1, 2016.

Prepared by or under the supervision of: Darin T. Espigh

SDR-RR-51

Request:

If applicable, please provide a copy of the billing and payment terms for all contracts between the Company and its parent or an affiliated company for services. Further, to the extent that the parent or affiliated company provides service to non-affiliated companies, please provide the corresponding billing and payment terms.

Response:

Please see the response to III-A-22.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-52

Request:

Please provide the annual level of outside services employed for the preceding three calendar years. Include in your response a breakdown of the test year amount indicating the service provider and the type of service performed.

Response:

Please see the response to III-A-28.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-53

Request:

Please describe each budgeted or planned cost savings program to be implemented during the historic or future year. Please identify the cost of implementing the program and the anticipated annual savings.

Response:

For a discussion of past cost savings programs, please see the response to SDR-RR-53 in UGI Gas's prior rate case at Docket No. R-2024-3052716, as well as the Direct Testimony of Hans G. Bell, UGI Gas Statement No. 1, in that case. There are no programmatic cost savings plans included in this case.

Prepared by or under the supervision of: Hans G. Bell

SDR-RR-54

Request:

Please explain how the Company has treated reserve accruals and balances for ratemaking purposes and provide the requested level of any self-funded reserve accruals by type of item.

Response:

Please refer to Attachment SDR-RR-54.

Prepared by or under the supervision of: Amy M. Keller

UGI Utilities, Inc. - Gas Division
Schedule of Reserve Accruals and Balances
(Thousands of Dollars)

Reserve Type	HTY Balance 9/30/25	Expense Treatment for Ratemaking Purposes	Related Adjustment Schedules (1)
Environmental	$68,876	Adjusted to a three-year historical average, plus or minus the amount of reconcilable cost differences since the last rate case (2)	Schedule D-8
Bad Debt	$13,893	Adjusted by applying the three-year historical average uncollectible percentage to adjusted revenues	Schedule D-11
Workers' Compensation	$1,312	No adjustment required (3)	None
Medical	$2,042	No adjustment required (3)	None
Injuries & Damages	$2,103	Adjusted to a three-year historical average	Schedule D-15

(1) Each respective schedule is disclosed in UGI Gas Exhibit A (Historic), Exhibit A (Future) and Exhibit A (Fully Projected).
(2) Refer to the Direct Testimony of Amy M. Keller, UGI Gas Statement No. 5 for discussion of the environmental adjustment.
(3) There are no related ratemaking adjustments required, as expenses are budgeted on a normalized basis.

SDR-RR-55

Request:

Please provide a copy of the corporate federal tax returns and supporting schedules for the preceding three years and, if applicable, a copy of the calculation work papers for the Company's consolidated tax savings adjustment.

Response:

UGI Gas is included as part of a consolidated federal income tax return. Since the complete federal tax return is a voluminous document, only excerpts from the preceding three years' returns are provided. Please see Attachment SDR-RR-55 for these excerpts. The complete tax returns are available at UGI Corporation headquarters in King of Prussia, PA.

Please also see the response to II-A-26 for a discussion of the consolidated tax savings adjustment.

Prepared by or under the supervision of: Darin T. Espigh

Form **1120**
Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2021 or tax year beginning 10/01/2021 , ending 09/30/2022

▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123

2021

A Check if:
1a Consolidated return (attach Form 851) . X
b Life/nonlife consolidated return . . .
2 Personal holding co. (attach Sch. PH) . . .
3 Personal service corp. (see instructions) . . .
4 Schedule M-3 attached X

TYPE OR PRINT

Name: UGI Corporation & Subsidiaries

B Employer identification number: 23-2668356

Number, street, and room or suite no. If a P.O. box, see instructions.: P.O. BOX 858

C Date incorporated: 12/01/1994

City or town, state or province, country, and ZIP or foreign postal code: Valley Forge, PA 19482

D Total assets (see instructions): $ 14,065,004,361.

E Check if: (1) ☐ Initial return (2) ☐ Final return (3) ☐ Name change (4) ☐ Address change

Income	1a	Gross receipts or sales	1a	4,512,012,214.	
	b	Returns and allowances	1b		
	c	Balance. Subtract line 1b from line 1a		1c	4,512,012,214.
	2	Cost of goods sold (attach Form 1125-A)		2	3,181,903,035.
	3	Gross profit. Subtract line 2 from line 1c		3	1,330,109,179.
	4	Dividends and inclusions (Schedule C, line 23)		4	253,224,676.
	5	Interest See Statement 3.		5	6,665,517.
	6	Gross rents		6	
	7	Gross royalties		7	
	8	Capital gain net income (attach Schedule D (Form 1120))		8	NONE
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)		9	16,270,283.
	10	Other income (see instructions - attach statement) See Statement 6.		10	235,523,819.
	11	**Total income.** Add lines 3 through 10 ▶		11	1,841,793,474.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶		12	22,283,444.
	13	Salaries and wages (less employment credits)		13	157,413,188.
	14	Repairs and maintenance See Statement 10.		14	168,312,748.
	15	Bad debts See Statement 13.		15	18,652,729.
	16	Rents See Statement 14.		16	2,761,478.
	17	Taxes and licenses See Statement 16.		17	70,568,037.
	18	Interest (see instructions) See Statement 22.		18	153,742,988.
	19	Charitable contributions See Statement 25.		19	7,286,591.
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)		20	342,841,683.
	21	Depletion		21	221,721.
	22	Advertising See Statement 27.		22	2,462,383.
	23	Pension, profit-sharing, etc., plans		23	21,863,243.
	24	Employee benefit programs		24	25,463,960.
	25	Reserved for future use		25	
	26	Other deductions (attach statement) See Statement 28.		26	512,175,912.
	27	**Total deductions** Add lines 12 through 26 ▶		27	1,506,050,105.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11		28	335,743,369.
	29a	Net operating loss deduction (see instructions)	29a 8,478,000.		
	b	Special deductions (Schedule C, line 24)	29b 193,531,159.		
	c	Add lines 29a and 29b		29c	202,009,159.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions		30	133,734,210.
	31	Total tax (Schedule J, Part I, line 11)		31	5,073,127.
	32	Reserved for future use		32	
	33	Total payments and credits (Schedule J, Part III, line 23)		33	18,525,183.
	34	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ ☐		34	
	35	**Amount owed.** If line 33 is smaller than the total of lines 31 and 34, enter amount owed		35	
	36	**Overpayment.** If line 33 is larger than the total of lines 31 and 34, enter amount overpaid		36	13,452,056.
	37	Enter amount from line 36 you want: **Credited to 2022 estimated tax** ▶ 13,452,056. **Refunded** ▶		37	

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer Kathleen R Rodes — Date 07/17/2023 — Title VP Global Tax

May the IRS discuss this return with the preparer shown below? See instructions. ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

UGI Corporation & Subsidiaries 23-2668356

Schedule C **Dividends, Inclusions, and Special Deductions** (see instructions)	(a) Dividends and inclusions	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	NONE	50	NONE
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		65	
3 Dividends on certain debt-financed stock of domestic and foreign corporations		See instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		23.3	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		26.7	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		50	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		65	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Subtotal.** Add lines 1 through 8. See instructions for limitations	NONE	See instructions	NONE
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Foreign-source portion of dividends received from a specified 10%-owned foreign corporation (excluding hybrid dividends) (see instructions)	133,837,642.	100	133,837,642.
14 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, 12, or 13 (including any hybrid dividends)			
15 Reserved for future use			
16a Subpart F inclusions derived from the sale by a controlled foreign corporation (CFC) of the stock of a lower-tier foreign corporation treated as a dividend (attach Form(s) 5471) (see instructions)		100	
b Subpart F inclusions derived from hybrid dividends of tiered corporations (attach Form(s) 5471) (see instructions)			
c Other inclusions from CFCs under subpart F not included on line 16a, 16b, or 17 (attach Form(s) 5471) (see instructions)			
17 Global Intangible Low-Taxed Income (GILTI) (attach Form(s) 5471 and Form 8992)	97,064,776.		
18 Gross-up for foreign taxes deemed paid	22,322,258.		
19 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
20 Other dividends			
21 Deduction for dividends paid on certain preferred stock of public utilities			
22 Section 250 deduction (attach Form 8993)			59,693,517.
23 **Total dividends and inclusions.** Add column (a), lines 9 through 20. Enter here and on page 1, line 4	253,224,676.		
24 **Total special deductions.** Add column (c), lines 9 through 22. Enter here and on page 1, line 29b			193,531,159.

UGI Corporation & Subsidiaries 23-2668356

Schedule J Tax Computation and Payment (see instructions)

Part I - Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. See instructions			2	28,084,184.
3	Base erosion minimum tax amount (attach Form 8991)			3	
4	Add lines 2 and 3			4	28,084,184.
5a	Foreign tax credit (attach Form 1118)	5a	18,172,289.		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	4,838,768.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	23,011,057.
7	Subtract line 6 from line 4			7	5,073,127.
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Interest/tax due under section 453A(c) and/or section 453(l)	9f			
g	Other (see instructions - attach statement)	9g			
10	**Total.** Add lines 9a through 9g			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	5,073,127.

Part II - Reserved For Future Use

12	Reserved for future use			12	

Part III - Payments and Refundable Credits

13	2020 overpayment credited to 2021			13	3,917,724.
14	2021 estimated tax payments			14	10,600,000.
15	2021 refund applied for on Form 4466			15	( )
16	Combine lines 13, 14, and 15			16	14,517,724.
17	Tax deposited with Form 7004			17	4,000,000.
18	Withholding (see instructions)			18	
19	**Total payments.** Add lines 16, 17, and 18			19	18,517,724.
20	Refundable credits from:				
a	Form 2439	20a			
b	Form 4136	20b	7,459.		
c	Reserved for future use	20c			
d	Other (attach statement - see instructions)	20d			
21	**Total credits.** Add lines 20a through 20d			21	7,459.
22	Reserved for future use			22	
23	**Total payments and credits.** Add lines 19 and 21. Enter here and on page 1, line 33			23	18,525,183.

UGI Corporation & Subsidiaries 23-2668356

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: **a** ☐ Cash **b** ☒ Accrual **c** ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group?		X
	If "Yes," enter name and EIN of the parent corporation ▶		
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock
See Statement 49			

b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
See Statement 51			

6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
	If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. See the instructions for Form 5452. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter: **(a)** Percentage owned ▶ _____ and **(b)** Owner's country ▶ _____ **(c)** The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ _____		X
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here (see instructions) ▶ ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12	Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a.) ▶ $ 23,164,154.		

UGI Corporation & Subsidiaries 23-2668356

Schedule K **Other Information** *(continued from page 4)*

		Yes	No
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15 a	Did the corporation make any payments in 2021 that would require it to file Form(s) 1099?		X
b	If "Yes," did or will the corporation file required Form(s) 1099?		
16	During this tax year, did the corporation have an 80%-or-more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X
20	Is the corporation operating on a cooperative basis?		X
21	During the tax year, did the corporation pay or accrue any interest or royalty for which the deduction is not allowed under section 267A? See instructions		X
	If "Yes," enter the total amount of the disallowed deductions ▶ $		
22	Does the corporation have gross receipts of at least $500 million in any of the 3 preceding tax years? (See sections 59A(e)(2) and (3))	X	
	If "Yes," complete and attach Form 8991.		
23	Did the corporation have an election under section 163(j) for any real property trade or business or any farming business in effect during the tax year? See instructions		X
24	Does the corporation satisfy one or more of the following? See instructions		X
a	The corporation owns a pass-through entity with current, or prior year carryover, excess business interest expense.		
b	The corporation's aggregate average annual gross receipts (determined under section 448(c)) for the 3 tax years preceding the current tax year are more than $26 million and the corporation has business interest expense.		
c	The corporation is a tax shelter and the corporation has business interest expense. If "Yes," complete and attach Form 8990.		
25	Is the corporation attaching Form 8996 to certify as a Qualified Opportunity Fund?		X
	If "Yes," enter amount from Form 8996, line 15 ▶ $		
26	Since December 22, 2017, did a foreign corporation directly or indirectly acquire substantially all of the properties held directly or indirectly by the corporation, and was the ownership percentage (by vote or value) for purposes of section 7874 greater than 50% (for example, the shareholders held more than 50% of the stock of the foreign corporation)? If "Yes," list the ownership percentage by vote and by value. See instructions		X
	Percentage: By Vote By Value		

UGI Corporation & Subsidiaries 23-2668356

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	Beginning of tax year (b)	End of tax year (c)	End of tax year (d)
1 Cash		413,305,966.		282,602,206.
2a Trade notes and accounts receivable	317,889,182.		440,439,621.	
b Less allowance for bad debts	(20,507,221.)	297,381,961.	(21,711,296.)	418,728,325.
3 Inventories		154,296,370.		278,547,133.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 58	590,961,605.		58,528,288.
7 Loans to shareholders		-131,617,876.		
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 65	3,852,365,103.		4,488,958,129.
10a Buildings and other depreciable assets	7,006,800,055.		7,857,532,134.	
b Less accumulated depreciation	(1,610,325,677.)	5,396,474,378.	(1,783,924,870.)	6,073,607,264.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		17,666,319.		18,624,218.
13a Intangible assets (amortizable only)	1,092,030,004.		1,081,405,701.	
b Less accumulated amortization	(52,126,777.)	1,039,903,227.	(59,560,023.)	1,021,845,678.
14 Other assets (attach statement)	Stmt 69	1,023,016,041.		1,423,563,120.
15 Total assets		12,653,753,094.		14,065,004,361.
Liabilities and Shareholders' Equity				
16 Accounts payable		404,887,804.		426,378,644.
17 Mortgages, notes, bonds payable in less than 1 year		330,606,428.		498,705,362.
18 Other current liabilities (attach statement)	Stmt 74	206,494,032.		190,923,992.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		3,711,051,219.		3,957,952,500.
21 Other liabilities (attach statement)	Stmt 83	1,901,883,477.		1,833,198,603.
22 Capital stock: a Preferred stock	212,851,586.		162,310,883.	
b Common stock	-1,791,134.	211,060,452.	100.	162,310,983.
23 Additional paid-in capital		1,908,707,665.		1,995,749,805.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		4,166,657,408.		5,056,796,079.
26 Adjustments to shareholders' equity (attach statement)		-161,401,148.		-16,770,038.
27 Less cost of treasury stock		(26,194,240.)		(40,241,569.)
28 Total liabilities and shareholders' equity		12,653,753,097.		14,065,004,361.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
6 Add lines 1 through 5		9 Add lines 7 and 8	
		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Schedule L, Line 25)

1 Balance at beginning of year	4,166,657,408.	5 Distributions: a Cash	295,803,601.
2 Net income (loss) per books	323,456,736.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 92	-124,362,991.
See Statement 89	738,122,546.	7 Add lines 5 and 6	171,440,610.
4 Add lines 1, 2, and 3	5,228,236,690.	8 Balance at end of year (line 4 less line 7)	5,056,796,080.

SCHEDULE M-3 (Form 1120)
(Rev. December 2019)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ **Attach to Form 1120 or 1120-C.**
▶ **Go to *www.irs.gov/Form1120* for instructions and the latest information.**

OMB No. 1545-0123

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es):
(1) [ ] Non-consolidated return
(2) [ ] Consolidated return (Form 1120 only)
(3) [X] Mixed 1120/L/PC group
(4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2021 Ending 09/30/2022

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock . . . . . UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	**4a**	1,073,289,876.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify) _____		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 96.	**5a**	(738,123,012.
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount)	**5b**	
6 a	Net income from nonincludible U.S. entities (attach statement)	**6a**	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	**6b**	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	**7a**	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement) Stmt. 96.	**7b**	-11,587,430.
c	Net income (loss) of other includible entities (attach statement)	**7c**	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	**8**	
9	Adjustment to reconcile income statement period to tax year (attach statement) Stmt. 97.	**9**	-11,402.
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	**10a**	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	**10b**	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 98.	**10c**	-111,296.
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	**11**	323,456,736.

Note: Part I, line 11, must equal Part II, line 30, column (a), or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶	17,906,031,365.	11,831,983,457.
b	Removed on Part I, line 5 ▶	2,024,855,342.	1,544,293,181.
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** [X] Consolidated group **(2)** [ ] Parent corp **(3)** [ ] Consolidated eliminations **(4)** [ ] Subsidiary corp **(5)** [X] Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** [ ] 1120 group **(7)** [ ] 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

Nonlife Consolidation |

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 39)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	323,609,977.	-76,299,314.	88,337,709.	335,648,372.
b PC insurance subgroup reconciliation totals	-153,241.	3,498.	246,488.	96,745.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	323,456,736.	-76,295,816.	88,584,197.	335,745,117.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☐ Subsidiary corp **(5)** ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☒ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120 Subgroup

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions			97,064,775.	97,064,775.
4 Gross-up for foreign taxes deemed paid		22,322,258.		22,322,258.
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	132,003,427.		1,834,215.	133,837,642.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	-74,528,344.	-26,475,472.		-101,003,816.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,605,059.	32,650.	3,017.	6,640,726.
14 Total accrual to cash adjustment				
15 Hedging transactions	141,550,387.	181,236,086.		322,786,473.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(3,291,749,256.)	7,288,918.		(3,284,460,338.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments		-129,872.		-129,872.
20 Unearned/deferred revenue	-12,160,598.	11,741,398.		-419,200.
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	265,219.	-351,787.	8,499.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-234,491.		-234,491.
e Abandonment losses				
f Worthless stock losses (attach statement)			-18,124,000.	-18,124,000.
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used			4,711,563.	4,711,563.
25 Other income (loss) items with differences (attach statement)	2,765,618.	1,128,028.	2,479,331.	6,372,977.
26 **Total income (loss) items.** Combine lines 1 through 25	-3,095,248,488.	196,557,716.	87,977,400.	-2,810,713,372.
27 **Total expense/deduction items** (from Part III, line 39)	-520,231,384.	-272,857,030.	360,309.	-792,728,105.
28 Other items with no differences	3,939,089,849.			3,939,089,849.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	323,609,977.	-76,299,314.	88,337,709.	335,648,372.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	323,609,977.	-76,299,314.	88,337,709.	335,648,372.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☐ Subsidiary corp **(5)** ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☒ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120 Subgroup

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	23,624,272.		-23,624,272.	
2 U.S. deferred income tax expense	45,509,581.	-97,375.	-45,412,206.	
3 State and local current income tax expense	16,747,459.	-626,869.		16,120,590.
4 State and local deferred income tax expense	-17,895,526.	17,895,526.		
5 Foreign current income tax expense (other than foreign withholding taxes)	-10,146,653.	10,146,653.		
6 Foreign deferred income tax expense	-44,417,026.		44,417,026.	
7 Foreign withholding taxes				
8 Interest expense (see instructions)	159,468,276.	-5,725,288.		153,742,988.
9 Stock option expense	4,686,334.	-475,505.	18,775,100.	22,985,929.
10 Other equity-based compensation	6,287,045.	-5,063,363.	937,199.	2,160,881.
11 Meals and entertainment	837,315.		-527,673.	309,642.
12 Fines and penalties	108,916.		-136,953.	-28,037.
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation	5,607,648.		-2,607,648.	3,000,000.
16 Pension and profit-sharing	9,035,687.	10,457,074.	-321,646.	19,171,115.
17 Other post-retirement benefits	3,657,356.	-965,228.		2,692,128.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	3,087,253.	12,373.	-750.	3,098,876.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward			4,187,715.	4,187,715.
22 Domestic production activities deduction (see instructions)				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs		745,044.		745,044.
26 Amortization/impairment of goodwill		23,175,544.		23,175,544.
27 Amortization of acquisition, reorganization, and start-up costs		676,918.		676,918.
28 Other amortization or impairment write-offs	11,109,510.	10,103,760.	6,614,773.	27,828,043.
29 Reserved				
30 Depletion		221,721.		221,721.
31 Depreciation	215,526,363.	127,315,320.		342,841,683.
32 Bad debt expense	19,895,151.	-1,242,422.		18,652,729.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	4,266,822.	-1,570,145.		2,696,677.
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Section 162(r) - FDIC premiums paid by certain large financial institutions (see instructions)				
38 Other expense/deduction items with differences (attach statement)	63,235,601.	87,873,292.	-2,660,974.	148,447,919.
39 **Total expense/deduction items.** Combine lines 1 through 38. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	520,231,384.	272,857,030.	-360,309.	792,728,105.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120-PC Subgroup |

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 11)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions (attach statement)				
13 Interest income (attach Form 8916-A)	24,791.			24,791.
14 Hedging transactions				
15 Mark-to-market income (loss)				
16 Premium income (attach statement)	67,688.	1,251.		68,939.
17 Sale versus lease (for sellers and/or lessors)				
18 Section 481(a) adjustments				
19 Reserved for future use				
20 Income recognition from long-term contracts				
21 Original issue discount and other imputed interest				
22 Reserved for future use				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than pass-through entities	-284,488.		284,488.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities			1,748.	1,748.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	-192,009.	1,251.	286,236.	95,478.
27 **Total expense/deduction items** (from Part III, line 40)	45,541.	2,247.	-39,748.	8,040.
28 Other items with no differences	-6,773.			-6,773.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-153,241.	3,498.	246,488.	96,745.
b 1120 subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-153,241.	3,498.	246,488.	96,745.

Note: Line 30, column (a), must equal the amount on Part I, line 11, and column (d) must equal Form 1120-PC, Schedule A, line 35.

Schedule M-3 (Form 1120-PC) (Rev. 12-2021)

Name of corporation (common parent, if consolidated return) | Employer identification number

UGI Corporation | 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | Employer identification number

1120-PC Subgroup |

Part III **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items** (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	24,546.		-24,546.	
2 U.S. deferred income tax expense	-64,294.		64,294.	
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Stock option expense				
9 Other equity-based compensation				
10 Meals and entertainment				
11 Fines and penalties				
12 Judgments, damages, awards, and similar costs				
13 Parachute payments				
14 Compensation with section 162(m) limitation				
15 Pension and profit-sharing				
16 Other post-retirement benefits				
17 Deferred compensation				
18 Charitable contribution of cash and tangible property				
19 Charitable contribution of intangible property				
20 Charitable contribution limitation/carryforward				
21 Write-off of premium receivables				
22 Guarantee fund assessments				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization of acquisition, reorganization, and start-up costs				
27 Amortization/impairment of goodwill, insurance in force, and ceding commissions	13,828.	-13,829.		-1.
28 Other amortization or impairment write-offs		5,515.		5,515.
29 Discounting of unpaid losses (section 846) (attach statement)	-17,078.	2,186.		-14,892.
30 Reduction of loss deduction (section 832(b)(5)(B))				
31 Depreciation				
32 Bad debt expense and/or agency balances written off				
33 Reserved for future use				
34 Corporate-owned life insurance premiums				
35 Purchase versus lease (for purchasers and/or lessees)				
36 Interest expense (attach Form 8916-A)				
37 Research and development costs				
38 Section 118 exclusion (attach statement)				
39 Other expense/deduction items with differences (attach statement)	-2,543.	3,881.		1,338.
40 **Total expense/deduction items.** Combine lines 1 through 39. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	-45,541.	-2,247.	39,748.	-8,040.

Consolidated Schedules
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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	4,512,012,214.			4,512,012,214.
1b	Returns and allowances				
1c	Balance	4,512,012,214.			4,512,012,214.
2	Cost of goods sold	3,181,903,035.			3,181,903,035.
3	Gross profit	1,330,109,179.			1,330,109,179.
4	Dividends	253,224,676.			253,224,676.
5	Interest	6,665,517.			6,665,517.
6	Gross rents				
7	Gross royalties				
8	Capital gain net income	1,748.		-1,748.	NONE
9	Net gain or (loss) from Form 4797	16,270,283.			16,270,283.
10	Other income	235,523,819.			235,523,819.
11	Total income	1,841,795,222.		-1,748.	1,841,793,474.
12	Compensation of officers	22,283,444.			22,283,444.
13	Salaries and wages	157,413,188.			157,413,188.
14	Repairs and maintenance	168,312,748.			168,312,748.
15	Bad debts	18,652,729.			18,652,729.
16	Rents	2,761,478.			2,761,478.
17	Taxes and licenses	70,568,037.			70,568,037.
18	Interest	153,742,988.			153,742,988.
19	Charitable contributions	7,286,591.			7,286,591.
20	Depreciation	342,841,683.			342,841,683.
21	Depletion	221,721.			221,721.
22	Advertising	2,462,383.			2,462,383.
23	Pension, profit-sharing etc., plans	21,863,243.			21,863,243.
24	Employee benefit programs	25,463,960.			25,463,960.
25	Reserved for future use				
26	Other deductions	512,175,912.			512,175,912.
27	Total deductions	1,506,050,105.			1,506,050,105.
28	Taxable income before NOL & Spec. Deductions	335,745,117.	NONE	-1,748.	335,743,369.
29	NOL,Spec. deductions	202,009,159.			202,009,159.
30	Taxable income	133,735,958.	NONE	-1,748.	133,734,210.

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		1120C Subgroup	1120 PC Subgroup
Consolidated Schedules			
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		23-2668356	03-0338831
1a	Gross receipts or sales	4,511,943,275.	68,939.
1b	Returns and allowances		
1c	Balance	4,511,943,275.	68,939.
2	Cost of goods sold	3,181,903,035.	
3	Gross profit	1,330,040,240.	68,939.
4	Dividends	253,224,676.	NONE
5	Interest	6,640,726.	24,791.
6	Gross rents		
7	Gross royalties		
8	Capital gain net income	NONE	1,748.
9	Net gain or (loss) from Form 4797	16,270,283.	
10	Other income	235,523,819.	
11	Total income	1,841,699,744.	95,478.
12	Compensation of officers	22,283,444.	
13	Salaries and wages	157,413,188.	
14	Repairs and maintenance	168,312,748.	
15	Bad debts	18,652,729.	
16	Rents	2,761,478.	
17	Taxes and licenses	70,659,984.	-91,947.
18	Interest	153,742,988.	
19	Charitable contributions	7,286,591.	
20	Depreciation	342,841,683.	
21	Depletion	221,721.	
22	Advertising	2,462,383.	
23	Pension, profit-sharing etc., plans	21,863,243.	
24	Employee benefit programs	25,463,960.	
25	Reserved for future use		
26	Other deductions	512,085,232.	90,680.
27	Total deductions	1,506,051,372.	-1,267.
28	Taxable income before NOL & Spec. Deductions	335,648,372.	96,745.
29	NOL,Spec. deductions	202,009,159.	NONE
30	Taxable income	133,639,213.	96,745.

Consolidated Schedules

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		Combined	UGI Eliminations	Adjustments	1120C Subgroup
1a	Gross receipts or sales	5,021,364,309.	-509,421,034.		4,511,943,275.
1b	Returns and allowances				
1c	Balance	5,021,364,309.	-509,421,034.		4,511,943,275.
2	Cost of goods sold	3,675,194,370.	-493,291,335.		3,181,903,035.
3	Gross profit	1,346,169,939.	-16,129,699.		1,330,040,240.
4	Dividends	312,281,929.	-59,057,253.		253,224,676.
5	Interest	6,403,378.	237,348.		6,640,726.
6	Gross rents				
7	Gross royalties				
8	Capital gain net income	7,376,536.		-7,376,536.	NONE
9	Net gain or (loss) from Form 4797	8,970,191.	-76,444.	7,376,536.	16,270,283.
10	Other income	235,447,375.	76,444.		235,523,819.
11	Total income	1,916,649,348.	-74,949,604.		1,841,699,744.
12	Compensation of officers	22,283,444.			22,283,444.
13	Salaries and wages	157,413,188.			157,413,188.
14	Repairs and maintenance	181,512,748.	-13,200,000.		168,312,748.
15	Bad debts	18,652,729.			18,652,729.
16	Rents	2,761,478.			2,761,478.
17	Taxes and licenses	70,659,984.			70,659,984.
18	Interest	153,505,640.	237,348.		153,742,988.
19	Charitable contributions	7,286,591.			7,286,591.
20	Depreciation	342,841,683.			342,841,683.
21	Depletion	221,721.			221,721.
22	Advertising	2,462,383.			2,462,383.
23	Pension, profit-sharing etc., plans	21,863,243.			21,863,243.
24	Employee benefit programs	25,463,960.			25,463,960.
25	Reserved for future use				
26	Other deductions	515,014,951.	-2,929,719.		512,085,232.
27	Total deductions	1,521,943,743.	-15,892,371.		1,506,051,372.
28	Taxable income before NOL & Spec. Deductions	394,705,605.	-59,057,233.		335,648,372.
29	NOL,Spec. deductions	261,066,412.	-59,057,253.		202,009,159.
30	Taxable income	133,639,193.	20.		133,639,213.

Consolidated Schedules
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		UGI Corporation	AmeriGas Propane, Inc.	AmeriGas Technology Group, Inc.	AmeriGas, Inc.	Ashtola Production Company	Eastfield International Holdings, Inc.	Energy Services Funding Corporation	Four Flags Drilling Company
		23-2668356	23-2786294	23-2861011	23-2716858	23-2101362	51-0385770	23-3099149	23-2178262
1a	Gross receipts or sales	2,340,476,933.							
1b	Returns and allowances								
1c	Balance	2,340,476,933.							
2	Cost of goods sold	1,889,044,543.							
3	Gross profit	451,432,390.							
4	Dividends	37,993,375.			21,063,878.				
5	Interest	1,213,705.							
6	Gross rents								
7	Gross royalties								
8	Capital gain net income	NONE	7,239,242.						
9	Net gain or (loss) from Form 4797	-283,278.							
10	Other income	74,465,214.	26,206,673.					10,829,153.	
11	Total income	564,821,406.	33,445,915.		21,063,878.			10,829,153.	
12	Compensation of officers	17,750,829.							
13	Salaries and wages	65,142,931.	741,076.						
14	Repairs and maintenance	26,928,638.							
15	Bad debts							4,335,076.	
16	Rents	1,943,862.							
17	Taxes and licenses	15,937,820.	2,280,505.		-19,884.			597,688.	
18	Interest	88,591,359.						108,316.	
19	Charitable contributions	4,521,507.	6,699.						
20	Depreciation	145,952,371.	5,447.						
21	Depletion	221,721.							
22	Advertising	630,231.							
23	Pension, profit-sharing etc., plans	10,618,254.							
24	Employee benefit programs	7,222,693.							
25	Reserved for future use								
26	Other deductions	79,458,832.	165,750.		1,456.	1,568.		402,896.	
27	Total deductions	464,921,048.	3,199,477.		-18,428.	1,568.		5,443,976.	
28	Taxable income before NOL & Spec. Deductions	99,900,358.	30,246,438.	NONE	21,082,306.	-1,568.	NONE	5,385,177.	NONE
29	NOL,Spec. deductions	37,993,375.			21,063,878.				
30	Taxable income	61,906,983.	30,246,438.	NONE	18,428.	-1,568.	NONE	5,385,177.	NONE

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		Homestead Holding Company	Newbury Holding Company	UGI Black Sea Enterprises, Inc.	UGI Energy Ventures, Inc	UGI Ethanol Development Company	UGI Europe, Inc.	UGI Hunlock Development Company	UGI HVAC Enterprises, Inc.
		51-0467618	30-0170818	23-2800542	71-0992456	23-2179048	23-3070112	23-3051491	51-0375688
1a	Gross receipts or sales						985,091,078.		
1b	Returns and allowances								
1c	Balance						985,091,078.		
2	Cost of goods sold						969,845,367.		
3	Gross profit						15,245,711.		
4	Dividends						253,224,676.		
5	Interest	-399,176.	161,938.				5,492,238.		
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								
9	Net gain or (loss) from Form 4797								-11,824.
10	Other income		-208,639.				986,191.		
11	Total income	-399,176.	-46,701.				274,948,816.		-11,824.
12	Compensation of officers								
13	Salaries and wages						1,439,215.		
14	Repairs and maintenance								
15	Bad debts								-4,608.
16	Rents		2,479.						
17	Taxes and licenses		125.				524,787.		3,213.
18	Interest						1,675,255.		
19	Charitable contributions								
20	Depreciation						47,788.		
21	Depletion								
22	Advertising						5,083.		
23	Pension, profit-sharing etc., plans						36,770.		-101,100.
24	Employee benefit programs						103,251.		-163,614.
25	Reserved for future use								
26	Other deductions	7,277.	6,632.				7,516,203.		201,464.
27	Total deductions	7,277.	9,236.				11,348,352.		-64,645.
28	Taxable income before NOL & Spec. Deductions	-406,453.	-55,937.	NONE	NONE	NONE	263,600,464.	NONE	52,821.
29	NOL,Spec. deductions						193,531,159.		
30	Taxable income	-406,453.	-55,937.	NONE	NONE	NONE	70,069,305.	NONE	52,821.

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		UGI International (Romania), Inc.	UGI LNG, Inc	UGI Penn HVAC Services, Inc	UGI Petroleum Products of Delaware, Inc	UGI Properties, Inc.	UGI Romania, Inc.	UGI Storage Company	UGID Holding Company
		23-2837401	51-0590685	23-1946160	51-0056772	23-2710207	23-2925615	32-0309503	51-0389590
1a	Gross receipts or sales		13,269,824.			2,571,671.		9,361,582.	
1b	Returns and allowances								
1c	Balance		13,269,824.			2,571,671.		9,361,582.	
2	Cost of goods sold							-235,521.	
3	Gross profit		13,269,824.			2,571,671.		9,597,103.	
4	Dividends								
5	Interest		580.					5,950.	
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								
9	Net gain or (loss) from Form 4797								
10	Other income		10,938.			8,045.		2,930.	
11	Total income		13,281,342.			2,579,716.		9,605,983.	
12	Compensation of officers								
13	Salaries and wages		737,873.					396,737.	
14	Repairs and maintenance		1,777,055.			336,680.		2,039,653.	
15	Bad debts								
16	Rents								
17	Taxes and licenses		313,035.			53,818.		385,811.	-82.
18	Interest					551,661.			
19	Charitable contributions							200,000.	
20	Depreciation		4,134,694.			490,356.		953,777.	
21	Depletion								
22	Advertising								
23	Pension, profit-sharing etc., plans		44,796.					24,239.	
24	Employee benefit programs		60,104.					32,945.	
25	Reserved for future use								
26	Other deductions		1,376,685.			614,899.		435,261.	5,260.
27	Total deductions		8,444,242.			2,047,414.		4,468,423.	5,178.
28	Taxable income before NOL & Spec. Deductions	NONE	4,837,100.	NONE	NONE	532,302.	NONE	5,137,560.	-5,178.
29	NOL,Spec. deductions								
30	Taxable income	NONE	4,837,100.	NONE	NONE	532,302.	NONE	5,137,560.	-5,178.

Consolidated Schedules
1120 Page 1

		UGI Utilities, Inc	AmeriGas Propane Holdings, Inc	Mountaineer Gas Company	Mountaineer Gas Holdings LP	Mountaintop Energy Holdings LLC	UGI Development Company
		23-1174060	84-1605503	55-0521087	20-1668503	27-4543948	23-1650159
1a	Gross receipts or sales	1,364,927,791.		257,828,540.			47,836,890.
1b	Returns and allowances						
1c	Balance	1,364,927,791.		257,828,540.			47,836,890.
2	Cost of goods sold	678,827,857.		106,705,607.			31,006,517.
3	Gross profit	686,099,934.		151,122,933.			16,830,373.
4	Dividends						
5	Interest	-114,465.					42,608.
6	Gross rents						
7	Gross royalties						
8	Capital gain net income		137,294.				
9	Net gain or (loss) from Form 4797	-1,625.	9,206,307.	63,116.			-2,505.
10	Other income	-4,367,403.	126,496,630.	1,021,199.			-3,556.
11	Total income	681,616,441.	135,840,231.	152,207,248.			16,866,920.
12	Compensation of officers	4,532,615.					
13	Salaries and wages	77,176,426.		9,664,369.			2,114,561.
14	Repairs and maintenance	140,944,599.					9,486,123.
15	Bad debts	13,025,169.		1,297,092.			
16	Rents	814,740.					397.
17	Taxes and licenses	29,912,228.	-1,016,826.	21,276,141.	-30.		411,635.
18	Interest	55,725,763.		6,853,286.			
19	Charitable contributions	2,545,293.	13,092.				
20	Depreciation	157,632,545.		29,339,714.			4,284,991.
21	Depletion						
22	Advertising	1,827,069.					
23	Pension, profit-sharing etc., plans	5,344,219.		5,984,679.			-88,614.
24	Employee benefit programs	13,004,238.		5,027,702.			176,641.
25	Reserved for future use						
26	Other deductions	73,240,306.	281,797,597.	68,128,612.	462.	28,232.	1,625,559.
27	Total deductions	575,725,210.	280,793,863.	147,571,595.	432.	28,232.	18,011,293.
28	Taxable income before NOL & Spec. Deductions	105,891,231.	-144,953,632.	4,635,653.	-432.	-28,232.	-1,144,373.
29	NOL,Spec. deductions					8,478,000.	
30	Taxable income	105,891,231.	-144,953,632.	4,635,653.	-432.	-8,506,232.	-1,144,373.

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Form **1120**
Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2022 or tax year beginning 10/01/2022 **, ending** 09/30/2023

Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123

2022

A Check if:
1a Consolidated return (attach Form 851) . X
b Life/nonlife consolidated return . . .
2 Personal holding co. (attach Sch. PH) . .
3 Personal service corp. (see instructions) . .
4 Schedule M-3 attached X

TYPE OR PRINT

Name: UGI Corporation & Subsidiaries

Number, street, and room or suite no. If a P.O. box, see instructions.: P.O. BOX 858

City or town, state or province, country, and ZIP or foreign postal code: Valley Forge, PA 19482

B Employer identification number: 23-2668356

C Date incorporated: 12/01/1994

D Total assets (see instructions): $ 12,893,138,533.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income	1a	Gross receipts or sales	1a	3,943,255,750.	
	b	Returns and allowances	1b		
	c	Balance. Subtract line 1b from line 1a		1c	3,943,255,750.
	2	Cost of goods sold (attach Form 1125-A)		2	2,766,575,070.
	3	Gross profit. Subtract line 2 from line 1c		3	1,176,680,680.
	4	Dividends and inclusions (Schedule C, line 23)		4	114,644,079.
	5	Interest See. Statement. 3.		5	14,258,735.
	6	Gross rents		6	977,367.
	7	Gross royalties		7	
	8	Capital gain net income (attach Schedule D (Form 1120))		8	34,904,453.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)		9	2,235,142.
	10	Other income (see instructions - attach statement) See. Statement. 6.		10	166,983,546.
	11	**Total income.** Add lines 3 through 10		11	1,510,684,002.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E)		12	-977,034.
	13	Salaries and wages (less employment credits)		13	189,743,987.
	14	Repairs and maintenance See. Statement. 9.		14	168,439,132.
	15	Bad debts See. Statement. 12.		15	24,683,798.
	16	Rents See. Statement. 13.		16	4,208,908.
	17	Taxes and licenses See. Statement. 15.		17	86,202,702.
	18	Interest (see instructions) See. Statement. 21.		18	158,949,006.
	19	Charitable contributions See. Statement. 24.		19	777,534.
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)		20	375,534,365.
	21	Depletion		21	460,507.
	22	Advertising See. Statement. 25.		22	2,267,036.
	23	Pension, profit-sharing, etc., plans		23	23,204,748.
	24	Employee benefit programs		24	26,074,153.
	25	Reserved for future use		25	
	26	Other deductions (attach statement) See. Statement. 27.		26	299,758,759.
	27	**Total deductions.** Add lines 12 through 26		27	1,359,327,601.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11		28	151,356,401.
	29a	Net operating loss deduction (see instructions)	29a 8,478,000.		
	b	Special deductions (Schedule C, line 24)	29b 107,655,234.		
	c	Add lines 29a and 29b		29c	116,133,234.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions		30	35,223,167.
	31	Total tax (Schedule J, Part I, line 11)		31	61,879.
	32	Reserved for future use		32	
	33	Total payments and credits (Schedule J, Part III, line 23)		33	17,334,322.
	34	Estimated tax penalty. See instructions. Check if Form 2220 is attached ☐		34	
	35	**Amount owed.** If line 33 is smaller than the total of lines 31 and 34, enter amount owed		35	
	36	**Overpayment.** If line 33 is larger than the total of lines 31 and 34, enter amount overpaid		36	17,272,443.
	37	Enter amount from line 36 you want: **Credited to 2023 estimated tax** 272,443. **Refunded**		37	17,000,000.

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer Kathleen S Rodes — Date 07/15/2024 — Title VP Global Tax

May the IRS discuss this return with the preparer shown below? See instructions. ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name			Firm's EIN	
Firm's address			Phone no.	

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2022)

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UGI Corporation & Subsidiaries 23-2668356

Schedule C Dividends, Inclusions, and Special Deductions (see instructions)	(a) Dividends and inclusions	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)		50	
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		65	
3 Dividends on certain debt-financed stock of domestic and foreign corporations		See instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		23.3	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		26.7	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		50	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		65	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Subtotal.** Add lines 1 through 8. See instructions for limitations		See instructions	
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members	11,783.	100	11,783.
12 Dividends from certain FSCs		100	
13 Foreign-source portion of dividends received from a specified 10%-owned foreign corporation (excluding hybrid dividends) (see instructions)	101,250,705.	100	101,250,705.
14 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, 12, or 13 (including any hybrid dividends)			
15 Reserved for future use			
16a Subpart F inclusions derived from the sale by a controlled foreign corporation (CFC) of the stock of a lower-tier foreign corporation treated as a dividend (attach Form(s) 5471) (see instructions)		100	
b Subpart F inclusions derived from hybrid dividends of tiered corporations (attach Form(s) 5471) (see instructions)			
c Other inclusions from CFCs under subpart F not included on line 16a, 16b, or 17 (attach Form(s) 5471) (see instructions)	596,102.		
17 Global Intangible Low-Taxed Income (GILTI) (attach Form(s) 5471 and Form 8992)	10,449,730.		
18 Gross-up for foreign taxes deemed paid	2,335,759.		
19 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
20 Other dividends			
21 Deduction for dividends paid on certain preferred stock of public utilities			
22 Section 250 deduction (attach Form 8993)			6,392,746.
23 **Total dividends and inclusions.** Add column (a), lines 9 through 20. Enter here and on page 1, line 4	114,644,079.		
24 **Total special deductions.** Add column (c), lines 9 through 22. Enter here and on page 1, line 29b			107,655,234.

Schedule J Tax Computation and Payment (see instructions)

Part I - Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ☐				
2	Income tax. See instructions			2	7,396,865.
3	Base erosion minimum tax amount (attach Form 8991)			3	
4	Add lines 2 and 3			4	7,396,865.
5a	Foreign tax credit (attach Form 1118)	5a	7,124,348.		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	210,638.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	7,334,986.
7	Subtract line 6 from line 4			7	61,879.
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Interest/tax due under section 453A(c) and/or section 453(l)	9f			
g	Other (see instructions - attach statement)	9g			
10	**Total.** Add lines 9a through 9g			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	61,879.

Part II - Reserved For Future Use

12	Reserved for future use			12	

Part III - Payments and Refundable Credits

13	2021 overpayment credited to 2022			13	9,534,322.
14	2022 estimated tax payments			14	7,800,000.
15	2022 refund applied for on Form 4466			15	( )
16	Combine lines 13, 14, and 15			16	17,334,322.
17	Tax deposited with Form 7004			17	
18	Withholding (see instructions)			18	
19	**Total payments.** Add lines 16, 17, and 18			19	17,334,322.
20	Refundable credits from:				
a	Form 2439	20a			
b	Form 4136	20b			
c	Reserved for future use	20c			
d	Other (attach statement - see instructions)	20d			
21	**Total credits.** Add lines 20a through 20d			21	
22	Reserved for future use			22	
23	**Total payments and credits.** Add lines 19 and 21. Enter here and on page 1, line 33			23	17,334,322.

UGI Corporation & Subsidiaries

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: **a** ☐ Cash **b** ☒ Accrual **c** ☐ Other (specify)		
2	See the instructions and enter the:		
a	Business activity code no. 551112		
b	Business activity HOLDING COMPANY		
c	Product or service N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group?		X
	If "Yes," enter name and EIN of the parent corporation		
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock
See Statement 48			

b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X		

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
See Statement 50			

6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
	If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. See the instructions for Form 5452. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock?		X
	For rules of attribution, see section 318. If "Yes," enter: **(a)** Percentage owned _____ and **(b)** Owner's country _____ **(c)** The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached _____		
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year $ _____		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) _____		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here (see instructions) ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12	Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a.) $ 14,686,154.		

UGI Corporation & Subsidiaries

Schedule K **Other Information** *(continued from page 4)*

		Yes	No
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year $		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15a	Did the corporation make any payments in 2022 that would require it to file Form(s) 1099?		X
b	If "Yes," did or will the corporation file required Form(s) 1099?		
16	During this tax year, did the corporation have an 80%-or-more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X
20	Is the corporation operating on a cooperative basis?		X
21	During the tax year, did the corporation pay or accrue any interest or royalty for which the deduction is not allowed under section 267A? See instructions		X
	If "Yes," enter the total amount of the disallowed deductions $		
22	Does the corporation have gross receipts of at least $500 million in any of the 3 preceding tax years? (See sections 59A(e)(2) and (3))		X
	If "Yes," complete and attach Form 8991.		
23	Did the corporation have an election under section 163(j) for any real property trade or business or any farming business in effect during the tax year? See instructions		X
24	Does the corporation satisfy one or more of the following? See instructions		X
a	The corporation owns a pass-through entity with current, or prior year carryover, excess business interest expense.		
b	The corporation's aggregate average annual gross receipts (determined under section 448(c)) for the 3 tax years preceding the current tax year are more than $27 million and the corporation has business interest expense.		
c	The corporation is a tax shelter and the corporation has business interest expense.		
	If "Yes," complete and attach Form 8990.		
25	Is the corporation attaching Form 8996 to certify as a Qualified Opportunity Fund?		X
	If "Yes," enter amount from Form 8996, line 15 $		
26	Since December 22, 2017, did a foreign corporation directly or indirectly acquire substantially all of the properties held directly or indirectly by the corporation, and was the ownership percentage (by vote or value) for purposes of section 7874 greater than 50% (for example, the shareholders held more than 50% of the stock of the foreign corporation)? If "Yes," list the ownership percentage by vote and by value. See instructions		X
	Percentage: By Vote By Value		

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UGI Corporation & Subsidiaries 23-2668356

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	Beginning of tax year (b)	End of tax year (c)	End of tax year (d)
1 Cash		282,602,206.		166,002,438.
2a Trade notes and accounts receivable	440,439,621.		374,700,195.	
b Less allowance for bad debts	(21,711,296.)	418,728,325.	(22,851,271.)	351,848,924.
3 Inventories		278,547,133.		146,876,597.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 57	58,528,288.		372,321,911.
7 Loans to shareholders				11,568,433.
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 64	4,488,958,129.		2,813,693,680.
10a Buildings and other depreciable assets	7,857,532,134.		8,508,225,749.	
b Less accumulated depreciation	(1,783,924,870.)	6,073,607,264.	(1,945,026,896.)	6,563,198,853.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		18,624,218.		35,800,326.
13a Intangible assets (amortizable only)	1,081,405,701.		1,057,060,425.	
b Less accumulated amortization	(59,560,023.)	1,021,845,678.	(50,083,014.)	1,006,977,411.
14 Other assets (attach statement)	Stmt 69	1,624,697,854.		1,424,849,960.
15 Total assets		14,266,139,095.		12,893,138,533.
Liabilities and Shareholders' Equity				
16 Accounts payable		426,378,644.		294,778,920.
17 Mortgages, notes, bonds payable in less than 1 year		498,705,362.		1,032,807,412.
18 Other current liabilities (attach statement)	Stmt 74	190,923,992.		298,562,356.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		3,957,952,500.		4,125,922,500.
21 Other liabilities (attach statement)	Stmt 82	2,034,333,337.		1,985,554,149.
22 Capital stock: a Preferred stock	162,310,883.		166,954,490.	
b Common stock	100.	162,310,983.	100.	166,954,590.
23 Additional paid-in capital		1,995,749,805.		2,015,617,733.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		5,056,796,079.		3,051,160,640.
26 Adjustments to shareholders' equity (attach statement)		-16,770,038.		-22,753,364.
27 Less cost of treasury stock		(40,241,569.)		(55,466,403.)
28 Total liabilities and shareholders' equity		14,266,139,095.		12,893,138,533.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Schedule L, Line 25)

1 Balance at beginning of year	5,056,796,079.	5 Distributions: a Cash	308,371,003.
2 Net income (loss) per books	-257,400,140.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 89	191,521,615.
See Statement 86	-1,248,342,681.	7 Add lines 5 and 6	499,892,618.
4 Add lines 1, 2, and 3	3,551,053,258.	8 Balance at end of year (line 4 less line 7)	3,051,160,640.

SCHEDULE M-3 (Form 1120) (Rev. December 2019)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C.
▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Non-consolidated return (2) [ ] Consolidated return (Form 1120 only) (3) [X] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2022 Ending 09/30/2023

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock . . . . . UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	**4a**	-1,502,227,039.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 92.	**5a**	(26,445,120).
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount) Stmt. 92.	**5b**	1,274,820,228.
6 a	Net income from nonincludible U.S. entities (attach statement)	**6a**	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	**6b**	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	**7a**	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement) Stmt. 92.	**7b**	-2,373,067.
c	Net income (loss) of other includible entities (attach statement)	**7c**	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	**8**	
9	Adjustment to reconcile income statement period to tax year (attach statement) Stmt. 94.	**9**	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	**10a**	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	**10b**	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 95.	**10c**	-1,175,142.
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	**11**	-257,400,140.

Note: Part I, line 11, must equal Part II, line 30, column (a), or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶	15,768,002,697.	11,374,048,508.
b	Removed on Part I, line 5 ▶	2,404,309,812.	958,042,100.
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) (Rev. 12-2019) Page **2**

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** [X] Consolidated group **(2)** [ ] Parent corp **(3)** [ ] Consolidated eliminations **(4)** [ ] Subsidiary corp **(5)** [X] Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** [ ] 1120 group **(7)** [ ] 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

Nonlife Consolidation |

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 39)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-257,450,488.	376,542,647.	32,110,889.	151,203,048.
b PC insurance subgroup reconciliation totals	50,348.	5,707.	97,298.	153,353.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-257,400,140.	376,548,354.	32,208,187.	151,356,401.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☐ Subsidiary corp **(5)** ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☒ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120 Subgroup

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions			11,045,832.	11,045,832.
4 Gross-up for foreign taxes deemed paid		2,335,759.		2,335,759.
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	107,408,968.		-6,158,377.	101,250,591.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	-592,499,147.	389,311,319.		-203,187,828.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	14,920,883.	8,101.	-133,078.	14,795,906.
14 Total accrual to cash adjustment				
15 Hedging transactions	-337,123,308.	237,247,221.		-99,876,087.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(2,442,630,699.)	2,358,294.		(2,440,272,405.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments		-262,002.		-262,002.
20 Unearned/deferred revenue		-9,454,745.		-9,454,745.
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	16,053,384.	86,397.	-16,209,094.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		14,720,983.		14,720,983.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory			407,236.	407,236.
24 Capital loss limitation and carryforward used			-6,734,763.	-6,734,763.
25 Other income (loss) items with differences (attach statement)	4,845,960.	-595,309.	56,565.	4,307,216.
26 **Total income (loss) items.** Combine lines 1 through 25	-3,229,023,959.	635,756,018.	-17,725,679.	-2,610,993,620.
27 **Total expense/deduction items** (from Part III, line 39)	-533,195,335.	-259,213,371.	49,836,568.	-742,572,138.
28 Other items with no differences	3,504,768,806.			3,504,768,806.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-257,450,488.	376,542,647.	32,110,889.	151,203,048.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-257,450,488.	376,542,647.	32,110,889.	151,203,048.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) (Rev. 12-2019)

Name of corporation (common parent, if consolidated return) | Employer identification number

UGI Corporation | 23-2668356

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☐ Subsidiary corp (5) ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☒ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | Employer identification number

1120 Subgroup

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-7,185,850.		7,185,850.	
2 U.S. deferred income tax expense	33,711,437.	-75,184.	-33,636,253.	
3 State and local current income tax expense	35,245,092.	-11,006,913.		24,238,179.
4 State and local deferred income tax expense	-13,053,764.	13,053,764.		
5 Foreign current income tax expense (other than foreign withholding taxes)	-13,672,676.	13,672,676.		
6 Foreign deferred income tax expense	6,881,707.		-6,881,707.	
7 Foreign withholding taxes				
8 Interest expense (see instructions)	205,845,303.	-46,896,297.		158,949,006.
9 Stock option expense	3,811,092.	-3,390,873.	2,282,554.	2,702,773.
10 Other equity-based compensation	8,305,116.	-7,480,092.	745,596.	1,570,620.
11 Meals and entertainment	1,913,912.		-1,104,837.	809,075.
12 Fines and penalties	109,069.		-154,999.	-45,930.
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation			-977,034.	-977,034.
16 Pension and profit-sharing	5,476,563.	13,770,123.		19,246,686.
17 Other post-retirement benefits	270,106.	3,687,956.		3,958,062.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	747,129.	30,405.		777,534.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction (see instructions)				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs		745,044.		745,044.
26 Amortization/impairment of goodwill	5,769,569.	23,175,544.	-5,769,569.	23,175,544.
27 Amortization of acquisition, reorganization, and start-up costs		628,223.		628,223.
28 Other amortization or impairment write-offs	15,859,801.	12,103,042.	7,021,463.	34,984,306.
29 Reserved				
30 Depletion		460,507.		460,507.
31 Depreciation	232,508,665.	143,025,699.		375,534,364.
32 Bad debt expense	25,963,848.	-1,280,050.		24,683,798.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	4,283,230.	-1,473,792.		2,809,438.
35 Research and development costs		-7,638,647.		-7,638,647.
36 Section 118 exclusion (attach statement)				
37 Section 162(r) - FDIC premiums paid by certain large financial institutions (see instructions)				
38 Other expense/deduction items with differences (attach statement)	-19,594,014.	114,102,236.	-18,547,632.	75,960,590.
39 **Total expense/deduction items.** Combine lines 1 through 38. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	533,195,335.	259,213,371.	-49,836,568.	742,572,138.

Name of corporation (common parent, if consolidated return) | Employer identification number

UGI Corporation | 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | Employer identification number

1120-PC Subgroup |

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 11)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	11,897.			11,897.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions (attach statement)				
13 Interest income (attach Form 8916-A)	32,578.			32,578.
14 Hedging transactions				
15 Mark-to-market income (loss)				
16 Premium income (attach statement)	76,784.	1,704.		78,488.
17 Sale versus lease (for sellers and/or lessors)				
18 Section 481(a) adjustments				
19 Reserved for future use				
20 Income recognition from long-term contracts				
21 Original issue discount and other imputed interest				
22 Reserved for future use				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than pass-through entities	-81,033.		81,033.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	40,226.	1,704.	81,033.	122,963.
27 **Total expense/deduction items** (from Part III, line 40)	-2,689.	4,003.	16,265.	17,579.
28 Other items with no differences	12,811.			12,811.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	50,348.	5,707.	97,298.	153,353.
b 1120 subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	50,348.	5,707.	97,298.	153,353.

Note: Line 30, column (a), must equal the amount on Part I, line 11, and column (d) must equal Form 1120-PC, Schedule A, line 35.

Name of corporation (common parent, if consolidated return) | Employer identification number

UGI Corporation | 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | Employer identification number

1120-PC Subgroup |

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	34,481.		-34,481.	
2 U.S. deferred income tax expense	-18,216.		18,216.	
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Stock option expense				
9 Other equity-based compensation				
10 Meals and entertainment				
11 Fines and penalties				
12 Judgments, damages, awards, and similar costs				
13 Parachute payments				
14 Compensation with section 162(m) limitation				
15 Pension and profit-sharing				
16 Other post-retirement benefits				
17 Deferred compensation				
18 Charitable contribution of cash and tangible property				
19 Charitable contribution of intangible property				
20 Charitable contribution limitation/carryforward				
21 Write-off of premium receivables				
22 Guarantee fund assessments				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization of acquisition, reorganization, and start-up costs				
27 Amortization/impairment of goodwill, insurance in force, and ceding commissions	15,896.	-15,896.		
28 Other amortization or impairment write-offs		5,516.		5,516.
29 Discounting of unpaid losses (section 846) (attach statement)	-26,461.	1,824.		-24,637.
30 Reduction of loss deduction (section 832(b)(5)(B))				
31 Depreciation				
32 Bad debt expense and/or agency balances written off				
33 Reserved for future use				
34 Corporate-owned life insurance premiums				
35 Purchase versus lease (for purchasers and/or lessees)				
36 Interest expense (attach Form 8916-A)				
37 Research and development costs				
38 Section 118 exclusion (attach statement)				
39 Other expense/deduction items with differences (attach statement)	-3,011.	4,553.		1,542.
40 **Total expense/deduction items.** Combine lines 1 through 39. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	2,689.	-4,003.	-16,265.	-17,579.

Consolidated Schedules
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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	3,943,255,750.			3,943,255,750.
1b	Returns and allowances				
1c	Balance	3,943,255,750.			3,943,255,750.
2	Cost of goods sold	2,766,575,070.			2,766,575,070.
3	Gross profit	1,176,680,680.			1,176,680,680.
4	Dividends	114,644,079.			114,644,079.
5	Interest	14,258,735.			14,258,735.
6	Gross rents	977,367.			977,367.
7	Gross royalties				
8	Capital gain net income	34,904,453.			34,904,453.
9	Net gain or (loss) from Form 4797	2,235,142.			2,235,142.
10	Other income	166,983,546.			166,983,546.
11	Total income	1,510,684,002.			1,510,684,002.
12	Compensation of officers	-977,034.			-977,034.
13	Salaries and wages	189,743,987.			189,743,987.
14	Repairs and maintenance	168,439,132.			168,439,132.
15	Bad debts	24,683,798.			24,683,798.
16	Rents	4,208,908.			4,208,908.
17	Taxes and licenses	86,202,702.			86,202,702.
18	Interest	158,949,006.			158,949,006.
19	Charitable contributions	777,534.			777,534.
20	Depreciation	375,534,365.			375,534,365.
21	Depletion	460,507.			460,507.
22	Advertising	2,267,036.			2,267,036.
23	Pension, profit-sharing etc., plans	23,204,748.			23,204,748.
24	Employee benefit programs	26,074,153.			26,074,153.
25	Reserved for future use				
26	Other deductions	299,758,759.			299,758,759.
27	Total deductions	1,359,327,601.			1,359,327,601.
28	Taxable income before NOL & Spec. Deductions	151,356,401.	NONE		151,356,401.
29	NOL,Spec. deductions	116,133,234.			116,133,234.
30	Taxable income	35,223,167.	NONE		35,223,167.

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		1120C Subgroup	1120 PC Subgroup
Consolidated Schedules			
1120 Page 1			
		23-2668356	03-0338831
1a	Gross receipts or sales	3,943,177,262.	78,488.
1b	Returns and allowances		
1c	Balance	3,943,177,262.	78,488.
2	Cost of goods sold	2,766,575,070.	
3	Gross profit	1,176,602,192.	78,488.
4	Dividends	114,632,182.	11,897.
5	Interest	14,226,157.	32,578.
6	Gross rents	977,367.	
7	Gross royalties		
8	Capital gain net income	34,904,453.	
9	Net gain or (loss) from Form 4797	2,235,142.	
10	Other income	166,983,546.	
11	Total income	1,510,561,039.	122,963.
12	Compensation of officers	-977,034.	
13	Salaries and wages	189,743,987.	
14	Repairs and maintenance	168,439,132.	
15	Bad debts	24,683,798.	
16	Rents	4,208,908.	
17	Taxes and licenses	86,320,255.	-117,553.
18	Interest	158,949,006.	
19	Charitable contributions	777,534.	
20	Depreciation	375,534,365.	
21	Depletion	460,507.	
22	Advertising	2,267,036.	
23	Pension, profit-sharing etc., plans	23,204,748.	
24	Employee benefit programs	26,074,153.	
25	Reserved for future use		
26	Other deductions	299,671,596.	87,163.
27	Total deductions	1,359,357,991.	-30,390.
28	Taxable income before NOL & Spec. Deductions	151,203,048.	153,353.
29	NOL,Spec. deductions	116,121,337.	11,897.
30	Taxable income	35,081,711.	141,456.

Consolidated Schedules

1120 Page 1

		Combined	UGI Eliminations	Adjustments	1120C Subgroup
1a	Gross receipts or sales	4,283,778,412.	-340,601,150.		3,943,177,262.
1b	Returns and allowances				
1c	Balance	4,283,778,412.	-340,601,150.		3,943,177,262.
2	Cost of goods sold	3,092,658,576.	-326,083,506.		2,766,575,070.
3	Gross profit	1,191,119,836.	-14,517,644.		1,176,602,192.
4	Dividends	241,592,228.	-126,960,046.		114,632,182.
5	Interest	16,157,670.	-1,931,513.		14,226,157.
6	Gross rents	2,132,109.	-1,154,742.		977,367.
7	Gross royalties				
8	Capital gain net income	47,427,334.		-12,522,881.	34,904,453.
9	Net gain or (loss) from Form 4797	2,302,830.	-69,313.	1,625.	2,235,142.
10	Other income	167,665,241.	-681,695.		166,983,546.
11	Total income	1,668,397,248.	-145,314,953.	-12,521,256.	1,510,561,039.
12	Compensation of officers	-977,034.			-977,034.
13	Salaries and wages	189,743,987.			189,743,987.
14	Repairs and maintenance	181,639,132.	-13,200,000.		168,439,132.
15	Bad debts	24,683,798.			24,683,798.
16	Rents	4,208,908.			4,208,908.
17	Taxes and licenses	86,320,255.			86,320,255.
18	Interest	161,631,527.	-2,682,521.		158,949,006.
19	Charitable contributions	215,104.		562,430.	777,534.
20	Depreciation	375,534,365.			375,534,365.
21	Depletion	460,507.			460,507.
22	Advertising	2,267,036.			2,267,036.
23	Pension, profit-sharing etc., plans	23,204,748.			23,204,748.
24	Employee benefit programs	26,074,153.			26,074,153.
25	Reserved for future use				
26	Other deductions	302,143,982.	-2,472,386.		299,671,596.
27	Total deductions	1,377,150,468.	-18,354,907.	562,430.	1,359,357,991.
28	Taxable income before NOL & Spec. Deductions	291,246,780.	-126,960,046.	-13,083,686.	151,203,048.
29	NOL,Spec. deductions	243,081,383.	-126,960,046.		116,121,337.
30	Taxable income	48,165,397.		-13,083,686.	35,081,711.

Consolidated Schedules
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		UGI Corporation	AmeriGas Propane, Inc.	AmeriGas Technology Group, Inc.	AmeriGas, Inc.	Ashtola Production Company	Eastfield International Holdings, Inc.	Energy Services Funding Corporation	Four Flags Drilling Company
		23-2668356	23-2786294	23-2861011	23-2716858	23-2101362	51-0385770	23-3099149	23-2178262
1a	Gross receipts or sales	1,824,100,457.							
1b	Returns and allowances								
1c	Balance	1,824,100,457.							
2	Cost of goods sold	1,610,803,268.							
3	Gross profit	213,297,189.							
4	Dividends	111,842,651.			15,117,281.				
5	Interest	8,043,120.							
6	Gross rents	645,396.							
7	Gross royalties								
8	Capital gain net income	NONE	12,532,808.						
9	Net gain or (loss) from Form 4797								
10	Other income	-90,143,004.	14,099,226.					10,002,324.	
11	Total income	243,685,352.	26,632,034.		15,117,281.			10,002,324.	
12	Compensation of officers	-977,034.							
13	Salaries and wages	79,971,396.	6,243.						
14	Repairs and maintenance	29,247,118.							
15	Bad debts							-1,807,067.	
16	Rents	3,586,580.							
17	Taxes and licenses	14,643,401.	809,612.		145.			601,094.	
18	Interest	66,882,970.						169,719.	
19	Charitable contributions		10,291.						
20	Depreciation	170,837,821.	5,447.						
21	Depletion	460,507.							
22	Advertising	759,452.							
23	Pension, profit-sharing etc., plans	8,988,467.							
24	Employee benefit programs	7,859,895.							
25	Reserved for future use								
26	Other deductions	-106,589,710.	-143,896.			1,207.		317,439.	
27	Total deductions	275,670,863.	687,697.		145.	1,207.		-718,815.	
28	Taxable income before NOL & Spec. Deductions	-31,985,511.	25,944,337.	NONE	15,117,136.	-1,207.	NONE	10,721,139.	NONE
29	NOL,Spec. deductions	111,842,651.			15,117,281.				
30	Taxable income	-143,828,162.	25,944,337.	NONE	-145.	-1,207.	NONE	10,721,139.	NONE

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Consolidated Schedules 1120 Page 1

		Homestead Holding Company 51-0467618	Newbury Holding Company 30-0170818	UGI Black Sea Enterprises, Inc. 23-2800542	UGI Energy Ventures, Inc 71-0992456	UGI Ethanol Development Company 23-2179048	UGI Europe, Inc. 23-3070112	UGI Hunlock Development Company 23-3051491	UGI International (Romania), Inc. 23-2837401
1a	Gross receipts or sales						544,517,237.		
1b	Returns and allowances								
1c	Balance						544,517,237.		
2	Cost of goods sold						501,258,940.		
3	Gross profit						43,258,297.		
4	Dividends						114,632,296.		
5	Interest		322,449.				10,255,953.		
6	Gross rents						408,756.		
7	Gross royalties								
8	Capital gain net income								
9	Net gain or (loss) from Form 4797								
10	Other income		-282,710.				1,281,935.		
11	Total income		39,739.				169,837,237.		
12	Compensation of officers								
13	Salaries and wages						948,213.		
14	Repairs and maintenance								
15	Bad debts								
16	Rents		2,375.						
17	Taxes and licenses		65.				309,108.		
18	Interest	2,682,521.					9,402,528.		
19	Charitable contributions								
20	Depreciation						66,971.		
21	Depletion								
22	Advertising						6,671.		
23	Pension, profit-sharing etc., plans						51,406.		
24	Employee benefit programs						42,551.		
25	Reserved for future use								
26	Other deductions	4,536.	2,782.				-50,519,486.		
27	Total deductions	2,687,057.	5,222.				-39,692,038.		
28	Taxable income before NOL & Spec. Deductions	-2,687,057.	34,517.	NONE	NONE	NONE	209,529,275.	NONE	NONE
29	NOL,Spec. deductions						107,643,451.		
30	Taxable income	-2,687,057.	34,517.	NONE	NONE	NONE	101,885,824.	NONE	NONE

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Consolidated Schedules
1120 Page 1

		UGI LNG, Inc	UGI Penn HVAC Services, Inc	UGI Petroleum Products of Delaware, Inc	UGI Properties, Inc.	UGI Romania, Inc.	UGI Storage Company	UGID Holding Company	UGI Utilities, Inc
		51-0590685	23-1946160	51-0056772	23-2710207	23-2925615	32-0309503	51-0389590	23-1174060
1a	Gross receipts or sales	13,200,000.					12,572,043.		1,546,644,916.
1b	Returns and allowances								
1c	Balance	13,200,000.					12,572,043.		1,546,644,916.
2	Cost of goods sold						28,479.		797,861,192.
3	Gross profit	13,200,000.					12,543,564.		748,783,724.
4	Dividends								
5	Interest	3,739.					27,687.		-2,640,521.
6	Gross rents				1,077,957.				
7	Gross royalties								
8	Capital gain net income				13,464,777.				
9	Net gain or (loss) from Form 4797				1,214,908.				-8,062.
10	Other income	10,938.					12,398,357.		95,542,832.
11	Total income	13,214,677.			15,757,642.		24,969,608.		841,677,973.
12	Compensation of officers								
13	Salaries and wages	714,451.					350,258.		94,991,077.
14	Repairs and maintenance	2,350,863.			233,873.		1,144,952.		143,890,841.
15	Bad debts								24,025,707.
16	Rents								619,635.
17	Taxes and licenses	312,397.			1,476,471.		1,840,221.	-303.	40,623,227.
18	Interest				573,656.				70,800,284.
19	Charitable contributions	313.					204,500.		
20	Depreciation	4,151,459.			244,263.		674,834.		163,583,479.
21	Depletion								
22	Advertising								1,497,853.
23	Pension, profit-sharing etc., plans	38,413.					18,805.		10,023,636.
24	Employee benefit programs	70,581.					34,634.		13,519,234.
25	Reserved for future use								
26	Other deductions	1,173,828.			1,512,886.		843,849.	3,226.	97,206,327.
27	Total deductions	8,812,305.			4,041,149.		5,112,053.	2,923.	660,781,300.
28	Taxable income before NOL & Spec. Deductions	4,402,372.	NONE	NONE	11,716,493.	NONE	19,857,555.	-2,923.	180,896,673.
29	NOL,Spec. deductions								
30	Taxable income	4,402,372.	NONE	NONE	11,716,493.	NONE	19,857,555.	-2,923.	180,896,673.

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Consolidated Schedules 1120 Page 1		AmeriGas Propane Holdings, Inc	Mountaineer Gas Company	Mountaineer Gas Holdings LP	Mountaintop Energy Holdings LLC	UGI Development Company
		83-4160550	55-0521087	20-1668503	27-4543948	23-1650159
1a	Gross receipts or sales		307,705,386.			35,038,373.
1b	Returns and allowances					
1c	Balance		307,705,386.			35,038,373.
2	Cost of goods sold		162,040,660.			20,666,037.
3	Gross profit		145,664,726.			14,372,336.
4	Dividends					
5	Interest					145,243.
6	Gross rents					
7	Gross royalties					
8	Capital gain net income	21,429,749.				NONE
9	Net gain or (loss) from Form 4797	1,046,624.	49,360.			
10	Other income	102,326,245.	1,181,024.			21,248,074.
11	Total income	124,802,618.	146,895,110.			35,765,653.
12	Compensation of officers					
13	Salaries and wages		10,581,230.			2,181,119.
14	Repairs and maintenance					4,771,485.
15	Bad debts		2,465,158.			
16	Rents					318.
17	Taxes and licenses	983,485.	23,935,389.			785,943.
18	Interest		11,119,849.			
19	Charitable contributions					
20	Depreciation		32,059,317.			3,910,774.
21	Depletion					
22	Advertising					3,060.
23	Pension, profit-sharing etc., plans		4,113,701.			-29,680.
24	Employee benefit programs		4,138,833.			408,425.
25	Reserved for future use					
26	Other deductions	276,977,980.	66,243,715.		32,750.	15,076,549.
27	Total deductions	277,961,465.	154,657,192.		32,750.	27,107,993.
28	Taxable income before NOL & Spec. Deductions	-153,158,847.	-7,762,082.	NONE	-32,750.	8,657,660.
29	NOL,Spec. deductions				8,478,000.	
30	Taxable income	-153,158,847.	-7,762,082.	NONE	-8,510,750.	8,657,660.

Form **1120**
Department of the Treasury
Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2023 or tax year beginning 10/01/2023 **, ending** 09/30/2024

Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123

2023

A Check if:
1a Consolidated return (attach Form 851) . X
b Life/nonlife consolidated return . . .
2 Personal holding co. (attach Sch. PH) . .
3 Personal service corp. (see instructions) . .
4 Schedule M-3 attached X

TYPE OR PRINT

Name
UGI Corporation & Subsidiaries

Number, street, and room or suite no. If a P.O. box, see instructions.
P.O. BOX 858

City or town, state or province, country, and ZIP or foreign postal code
Valley Forge, PA 19482

B Employer identification number
23-2668356

C Date incorporated
12/01/1994

D Total assets (see instructions)
$ 12,557,300,841.

E Check if: (1) ☐ Initial return (2) ☐ Final return (3) ☐ Name change (4) ☐ Address change

Income	1a	Gross receipts or sales	1a	3,248,985,029.	
	b	Returns and allowances	1b		
	c	Balance. Subtract line 1b from line 1a		1c	3,248,985,029.
	2	Cost of goods sold (attach Form 1125-A)		2	1,745,253,324.
	3	Gross profit. Subtract line 2 from line 1c		3	1,503,731,705.
	4	Dividends and inclusions (Schedule C, line 23)		4	105,240,423.
	5	Interest See Statement 6.		5	23,291,332.
	6	Gross rents		6	1,047,657.
	7	Gross royalties		7	
	8	Capital gain net income (attach Schedule D (Form 1120))		8	3,304,955.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)		9	19,822,373.
	10	Other income (see instructions - attach statement) See Statement 9.		10	49,892,769.
	11	**Total income.** Add lines 3 through 10		11	1,706,331,214.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E)		12	6,915,565.
	13	Salaries and wages (less employment credits)		13	169,997,944.
	14	Repairs and maintenance See Statement 12.		14	155,763,430.
	15	Bad debts See Statement 15.		15	26,073,254.
	16	Rents See Statement 16.		16	4,491,124.
	17	Taxes and licenses See Statement 18.		17	69,403,254.
	18	Interest (see instructions) See Statement 24.		18	223,411,687.
	19	Charitable contributions See Statement 27.		19	464,645.
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)		20	359,623,070.
	21	Depletion		21	466,005.
	22	Advertising See Statement 28.		22	1,685,899.
	23	Pension, profit-sharing, etc., plans		23	25,488,961.
	24	Employee benefit programs		24	26,047,486.
	25	Energy efficient commercial buildings deduction (attach Form 7205)		25	
	26	Other deductions (attach statement) See Statement 30.		26	473,512,975.
	27	**Total deductions.** Add lines 12 through 26		27	1,543,345,299.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11		28	162,985,915.
	29a	Net operating loss deduction (see instructions)	29a 6,208,154.		
	b	Special deductions (Schedule C, line 24)	29b 101,610,136.		
	c	Add lines 29a and 29b		29c	107,818,290.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions		30	55,167,625.
	31	Total tax (Schedule J, Part I, line 11)		31	45,035.
	32	Reserved for future use		32	
	33	Total payments and credits (Schedule J, Part II, line 23)		33	272,443.
	34	Estimated tax penalty. See instructions. Check if Form 2220 is attached ☐		34	
	35	**Amount owed.** If line 33 is smaller than the total of lines 31 and 34, enter amount owed		35	
	36	**Overpayment.** If line 33 is larger than the total of lines 31 and 34, enter amount overpaid		36	227,408.
	37	Enter amount from line 36 you want: **Credited to 2024 estimated tax** 227,408. **Refunded**		37	

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer Kathleen S Rodes — Date 07/15/2025 — Title VP Global Tax

May the IRS discuss this return with the preparer shown below? See instructions. X Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
TRAVIS WARD	TRAVIS WARD	07/15/2025		P01320271

Firm's name CROWE LLP — Firm's EIN 35-0921680

Firm's address 605 SEWARD AVE. NW GRAND RAPIDS, MI 49504-5584 — Phone no. 616-774-0774

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2023)

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UGI Corporation & Subsidiaries 23-2668356

Schedule C Dividends, Inclusions, and Special Deductions (see instructions)	(a) Dividends and inclusions	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)		50	
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		65	
3 Dividends on certain debt-financed stock of domestic and foreign corporations		See instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		23.3	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		26.7	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		50	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		65	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Subtotal.** Add lines 1 through 8. See instructions for limitations		See instructions	
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members	12,194.	100	12,194.
12 Dividends from certain FSCs		100	
13 Foreign-source portion of dividends received from a specified 10%-owned foreign corporation (excluding hybrid dividends) (see instructions)	97,967,654.	100	97,967,654.
14 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, 12, or 13 (including any hybrid dividends)			
15 Reserved for future use			
16a Subpart F inclusions derived from the sale by a controlled foreign corporation (CFC) of the stock of a lower-tier foreign corporation treated as a dividend (attach Form(s) 5471) (see instructions)		100	
b Subpart F inclusions derived from hybrid dividends of tiered corporations (attach Form(s) 5471) (see instructions)			
c Other inclusions from CFCs under subpart F not included on line 16a, 16b, or 17 (attach Form(s) 5471) (see instructions)			
17 Global Intangible Low-Taxed Income (GILTI) (attach Form(s) 5471 and Form 8992)	6,697,857.		
18 Gross-up for foreign taxes deemed paid	562,718.		
19 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
20 Other dividends			
21 Deduction for dividends paid on certain preferred stock of public utilities			
22 Section 250 deduction (attach Form 8993)			3,630,288.
23 **Total dividends and inclusions.** Add column (a), lines 9 through 20. Enter here and on page 1, line 4	105,240,423.		
24 **Total special deductions.** Add column (c), lines 9 through 22. Enter here and on page 1, line 29b			101,610,136.

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Schedule J Tax Computation and Payment (see instructions)

Part I - Tax Computation

1	Income tax. See instructions			1	11,585,201.
2	Base erosion minimum tax amount (attach Form 8991)			2	
3	Corporate alternative minimum tax from Form 4626, Part II, line 13 (attach Form 4626)			3	
4	Add lines 1, 2, and 3			4	11,585,201.
5a	Foreign tax credit (attach Form 1118)	5a	11,380,062.		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (see instructions - attach Form 3800)	5c	160,104.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	11,540,166.
7	Subtract line 6 from line 4			7	45,035.
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Interest/tax due under section 453A(c)	9f			
g	Interest/tax due under section 453(l)	9g			
z	Other (see instructions - attach statement)	9z			
10	**Total.** Add lines 9a through 9z			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	45,035.

Part II - Payments and Refundable Credits

12	Reserved for future use			12	
13	Preceding year's overpayment credited to the current year			13	272,443.
14	Current year's estimated tax payments			14	
15	Current year's refund applied for on Form 4466			15	( )
16	Combine lines 13, 14, and 15			16	272,443.
17	Tax deposited with Form 7004			17	
18	Withholding (see instructions)			18	
19	**Total payments.** Add lines 16, 17, and 18			19	272,443.
20	Refundable credits from:				
a	Form 2439	20a			
b	Form 4136	20b			
c	Reserved for future use	20c			
z	Other (attach statement - see instructions)	20z			
21	**Total credits.** Add lines 20a through 20z			21	
22	Elective payment election amount from Form 3800			22	
23	**Total payments and credits.** Add lines 19, 21, and 22. Enter here and on page 1, line 33			23	272,443.

UGI Corporation & Subsidiaries 23-2668356

Schedule K **Other Information** (see instructions)

		Yes	No
1	Check accounting method: **a** ☐ Cash **b** ☒ Accrual **c** ☐ Other (specify)		
2	See the instructions and enter the:		
a	Business activity code no. 551112		
b	Business activity HOLDING COMPANY		
c	Product or service N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group?		X
	If "Yes," enter name and EIN of the parent corporation		
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851,** Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock
See Statement 50			

b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
See Statement 54			

6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
	If "Yes," file **Form 5452,** Corporate Report of Nondividend Distributions. See the instructions for Form 5452. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7	At any time during this tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter: **(a)** Percentage owned _____ and **(b)** Owner's country _____ **(c)** The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached _____		X
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ☐ If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during this tax year $		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer)		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here (see instructions) ☐ If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12	Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a) $ 6,208,154.		

UGI Corporation & Subsidiaries 23-2668356

Schedule K Other Information *(continued from page 4)*

		Yes	No
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year $		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15a	Did the corporation make any payments that would require it to file Form(s) 1099?	X	
b	If "Yes," did or will the corporation file required Form(s) 1099?	X	
16	During this tax year, did the corporation have an 80%-or-more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?	X	
20	Is the corporation operating on a cooperative basis?		X
21	During this tax year, did the corporation pay or accrue any interest or royalty for which the deduction is not allowed under section 267A? See instructions		X
	If "Yes," enter the total amount of the disallowed deductions $		
22	Does this corporation have gross receipts of at least $500 million in any of the 3 preceding tax years? (See sections 59A(e)(2) and (3).)	X	
	If "Yes," complete and attach Form 8991.		
23	Did the corporation have an election under section 163(j) for any real property trade or business or any farming business in effect during this tax year? See instructions		X
24	Does the corporation satisfy one or more of the following? If "Yes," complete and attach Form 8990. See instructions	X	
a	The corporation owns a pass-through entity with current, or prior year carryover, excess business interest expense.		
b	The corporation's aggregate average annual gross receipts (determined under section 448(c)) for the 3 tax years preceding the current tax year are more than $29 million and the corporation has business interest expense.		
c	The corporation is a tax shelter and the corporation has business interest expense.		
25	Is the corporation attaching Form 8996 to certify as a Qualified Opportunity Fund?		X
	If "Yes," enter amount from Form 8996, line 15 $		
26	Since December 22, 2017, did a foreign corporation directly or indirectly acquire substantially all of the properties held directly or indirectly by the corporation, and was the ownership percentage (by vote or value) for purposes of section 7874 greater than 50% (for example, the shareholders held more than 50% of the stock of the foreign corporation)? If "Yes," list the ownership percentage by vote and by value. See instructions		X
	Percentage: By Vote By Value		
27	At any time during this tax year, did the corporation (a) receive a digital asset (as a reward, award, or payment for property or services); or (b) sell, exchange, or otherwise dispose of a digital asset (or a financial interest in a digital asset)? See instructions		X
28	Is the corporation a member of a controlled group?	X	
	If "Yes," attach Schedule O (Form 1120). See instructions.		
29	Corporate Alternative Minimum Tax:		
a	Was the corporation an applicable corporation under section 59(k)(1) in any prior tax year?		X
	If "Yes," go to question 29b. If "No," skip to question 29c.		
b	Is the corporation an applicable corporation under section 59(k)(1) in the current tax year because the corporation was an applicable corporation in the prior tax year?		X
	If "Yes," complete and attach Form 4626. If "No," continue to question 29c.		
c	Does the corporation meet the requirements of the safe harbor method as provided under section 59(k)(3)(A) for the current tax year? See instructions	X	
	If "No," complete and attach Form 4626. If "Yes," the corporation is not required to file Form 4626.		
30	Is the corporation required to file Form 7208 relating to the excise tax on repurchase of corporate stock (see instructions):		
a	Under the rules for stock repurchased by a covered corporation (or stock acquired by its specified affiliate)?		X
b	Under the applicable foreign corporation rules?		X
c	Under the covered surrogate foreign corporation rules?		X
	If "Yes" to either (a), (b), or (c), complete Form 7208, Excise Tax on Repurchase of Corporate Stock. See the Instructions for Form 7208.		
31	Is this a consolidated return with gross receipts or sales of $1 billion or more and a subchapter K basis adjustment, as described in the instructions, of $10 million or more?		X
	If "Yes," attach a statement. See instructions.		

UGI Corporation & Subsidiaries 23-2668356

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	Beginning of tax year (b)	End of tax year (c)	End of tax year (d)
1 Cash		166,002,438.		152,212,147.
2a Trade notes and accounts receivable	374,700,195.		299,732,369.	
b Less allowance for bad debts	(22,851,271.)	351,848,924.	(20,031,250.)	279,701,119.
3 Inventories		146,876,597.		140,830,121.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 70	372,321,911.		331,893,872.
7 Loans to shareholders		11,568,433.		229.
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 77	2,813,693,680.		2,539,988,548.
10a Buildings and other depreciable assets	8,508,225,749.		8,900,299,235.	
b Less accumulated depreciation	(1,945,026,896.)	6,563,198,853.	(2,091,262,098.)	6,809,037,137.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		35,800,326.		16,478,510.
13a Intangible assets (amortizable only)	1,057,060,425.		1,047,040,930.	
b Less accumulated amortization	(50,083,014.)	1,006,977,411.	(60,178,869.)	986,862,061.
14 Other assets (attach statement)	Stmt 81	1,424,849,960.		1,300,297,097.
15 Total assets		12,893,138,533.		12,557,300,841.
Liabilities and Shareholders' Equity				
16 Accounts payable		294,778,920.		273,153,359.
17 Mortgages, notes, bonds payable in less than 1 year		1,032,807,412.		807,091,531.
18 Other current liabilities (attach statement)	Stmt 86	298,562,356.		200,902,532.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		4,125,922,500.		4,759,012,500.
21 Other liabilities (attach statement)	Stmt 94	1,985,554,149.		1,985,866,099.
22 Capital stock: a Preferred stock	166,954,490.			
b Common stock	100.	166,954,590.	100.	100.
23 Additional paid-in capital		2,015,617,733.		2,188,805,688.
24 Retained earnings - Appropriated (attach statement)				333,456,794.
25 Retained earnings - Unappropriated		3,051,160,640.		2,132,241,443.
26 Adjustments to shareholders' equity (attach statement)		-22,753,364.		-67,083,431.
27 Less cost of treasury stock		(55,466,403.)		(56,145,774.)
28 Total liabilities and shareholders' equity		12,893,138,533.		12,557,300,841.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Schedule L, Line 25)

1 Balance at beginning of year	3,051,160,640.	5 Distributions: a Cash	318,384,003.
2 Net income (loss) per books	333,456,788.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 101	1,541,143,147.
See Statement 98	607,151,165.	7 Add lines 5 and 6	1,859,527,150.
4 Add lines 1, 2, and 3	3,991,768,593.	8 Balance at end of year (line 4 less line 7)	2,132,241,443.

SCHEDULE M-3 (Form 1120)
(Rev. December 2019)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ **Attach to Form 1120 or 1120-C.**
▶ **Go to *www.irs.gov/Form1120* for instructions and the latest information.**

OMB No. 1545-0123

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Non-consolidated return (2) [ ] Consolidated return (Form 1120 only) (3) [X] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2023 Ending 09/30/2024

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock . . . . . UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	**4a**	268,770,689.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify) _____		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 104	**5a**	(55,432,719.
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount) Stmt. 104	**5b**	121,513,140.
6 a	Net income from nonincludible U.S. entities (attach statement)	**6a**	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	**6b**	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	**7a**	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement) Stmt. 104	**7b**	-1,212,821.
c	Net income (loss) of other includible entities (attach statement)	**7c**	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	**8**	
9	Adjustment to reconcile income statement period to tax year (attach statement)	**9**	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement) Stmt. 105	**10a**	-12,194.
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	**10b**	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 105	**10c**	-169,307.
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	**11**	333,456,788.

Note: Part I, line 11, must equal Part II, line 30, column (a), or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶	15,097,859,311.	10,743,768,301.
b	Removed on Part I, line 5 ▶	2,540,558,470.	2,717,742,280.
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) (Rev. 12-2019) Page **2**

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** [X] Consolidated group **(2)** [ ] Parent corp **(3)** [ ] Consolidated eliminations **(4)** [ ] Subsidiary corp **(5)** [X] Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** [ ] 1120 group **(7)** [ ] 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

Nonlife Consolidation |

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 39)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	333,240,298.	-230,490,661.	60,076,308.	162,825,945.
b PC insurance subgroup reconciliation totals	216,490.	8,672.	-65,192.	159,970.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	333,456,788.	-230,481,989.	60,011,116.	162,985,915.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) (Rev. 12-2019) Page **2**

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☐ Subsidiary corp (5) ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☒ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120 Subgroup

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions			6,697,857.	6,697,857.
4 Gross-up for foreign taxes deemed paid			562,718.	562,718.
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	92,170,441.		5,797,213.	97,967,654.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	-210,369,751.	-32,185,873.		-242,555,624.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	20,031,530.	155,905.	154,483.	20,341,918.
14 Total accrual to cash adjustment				
15 Hedging transactions	-13,520,915.	-86,654,145.		-100,175,060.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,761,487,776.)	270,881.		(1,761,216,895.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments		-1,178,566.		-1,178,566.
20 Unearned/deferred revenue		4,956,220.		4,956,220.
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-224,023.	210,308.	13,715.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		19,808,658.		19,808,658.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory			325,772.	325,772.
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	3,538,629.	50.	-256,689.	3,281,990.
26 **Total income (loss) items.** Combine lines 1 through 25	-1,869,861,865.	-94,616,562.	13,295,069.	-1,951,183,358.
27 **Total expense/deduction items** (from Part III, line 39)	-663,038,747.	-135,874,099.	46,781,239.	-752,131,607.
28 Other items with no differences	2,866,140,910.			2,866,140,910.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	333,240,298.	-230,490,661.	60,076,308.	162,825,945.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	333,240,298.	-230,490,661.	60,076,308.	162,825,945.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

UGI Corporation | 23-2668356

Check applicable box(es): **(1)** ☐ Consolidated group **(2)** ☐ Parent corp **(3)** ☐ Consolidated eliminations **(4)** ☐ Subsidiary corp **(5)** ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: **(6)** ☒ 1120 group **(7)** ☐ 1120 eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

1120 Subgroup

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-46,627,714.		46,627,714.	
2 U.S. deferred income tax expense	101,962,746.		-101,962,746.	
3 State and local current income tax expense	11,353,429.	-1,021,628.	-27,430.	10,304,371.
4 State and local deferred income tax expense	33,926,493.	-33,926,493.		
5 Foreign current income tax expense (other than foreign withholding taxes)	-48,319,059.	48,319,059.		
6 Foreign deferred income tax expense	-2,909,219.		2,909,219.	
7 Foreign withholding taxes				
8 Interest expense (see instructions)	233,266,934.	-9,855,247.		223,411,687.
9 Stock option expense	1,594,989.	-2,268,819.		-673,830.
10 Other equity-based compensation	3,211,163.	-1,530,611.	302,038.	1,982,590.
11 Meals and entertainment	1,297,897.		-691,242.	606,655.
12 Fines and penalties	889,348.		-889,348.	
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation	17,386,001.		-10,470,436.	6,915,565.
16 Pension and profit-sharing	8,097,400.	14,246,378.		22,343,778.
17 Other post-retirement benefits	-143,023.	3,288,206.		3,145,183.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	457,176.			457,176.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction (see instructions)				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs		745,044.		745,044.
26 Amortization/impairment of goodwill	2,412,507.	22,436,478.	-2,412,507.	22,436,478.
27 Amortization of acquisition, reorganization, and start-up costs		579,529.		579,529.
28 Other amortization or impairment write-offs	81,537,940.	-46,307,449.	4,747,015.	39,977,506.
29 Reserved				
30 Depletion		466,005.		466,005.
31 Depreciation	225,207,483.	134,415,587.		359,623,070.
32 Bad debt expense	23,323,688.	2,749,566.		26,073,254.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	4,455,661.	-1,420,370.		3,035,291.
35 Research and development costs	9,446,456.	-9,446,456.		
36 Section 118 exclusion (attach statement)				
37 Section 162(r) - FDIC premiums paid by certain large financial institutions (see instructions)				
38 Other expense/deduction items with differences (attach statement)	1,210,451.	14,405,320.	15,086,484.	30,702,255.
39 **Total expense/deduction items.** Combine lines 1 through 38. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	663,038,747.	135,874,099.	-46,781,239.	752,131,607.

Name of corporation (common parent, if consolidated return) | **Employer identification number**

1120 PC Subgroup | 03-0338831

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | **Employer identification number**

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

	Income (Loss) Items (Attach statements for lines 1 through 11)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1	Income (loss) from equity method foreign corporations				
2	Gross foreign dividends not previously taxed				
3	Subpart F, QEF, and similar income inclusions				
4	Gross-up for foreign taxes deemed paid				
5	Gross foreign distributions previously taxed				
6	Income (loss) from equity method U.S. corporations				
7	U.S. dividends not eliminated in tax consolidation Stmt 24	12,194.			12,194.
8	Minority interest for includible corporations				
9	Income (loss) from U.S. partnerships				
10	Income (loss) from foreign partnerships				
11	Income (loss) from other pass-through entities				
12	Items relating to reportable transactions (attach statement)				
13	Interest income (attach Form 8916-A)	43,520.			43,520.
14	Hedging transactions				
15	Mark-to-market income (loss)				
16	Premium income (attach statement) Stmt 25	88,531.	1,935.		90,466.
17	Sale versus lease (for sellers and/or lessors)				
18	Section 481(a) adjustments				
19	Reserved for future use				
20	Income recognition from long-term contracts				
21	Original issue discount and other imputed interest				
22	Reserved for future use				
23a	Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than pass-through entities	113,514.		-113,514.	
b	Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c	Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d	Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e	Abandonment losses				
f	Worthless stock losses (attach statement)				
g	Other gain/loss on disposition of assets				
24	Capital loss limitation and carryforward used				
25	Other income (loss) items with differences (attach statement)				
26	**Total income (loss) items.** Combine lines 1 through 25	257,759.	1,935.	-113,514.	146,180.
27	**Total expense/deduction items** (from Part III, line 40)	-61,647.	6,737.	48,322.	-6,588.
28	Other items with no differences Stmt 26	20,378.			20,378.
29a	Mixed groups, see instructions. All others, combine lines 26 through 28	216,490.	8,672.	-65,192.	159,970.
b	1120 subgroup reconciliation totals				
c	Life insurance subgroup reconciliation totals				
30	**Reconciliation totals.** Combine lines 29a through 29c	216,490.	8,672.	-65,192.	159,970.

Note: Line 30, column (a), must equal the amount on Part I, line 11, and column (d) must equal Form 1120-PC, Schedule A, line 35.

Name of corporation (common parent, if consolidated return) | Employer identification number

1120 PC Subgroup | 03-0338831

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return) | Employer identification number

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	26,303.		-26,303.	
2 U.S. deferred income tax expense	22,019.		-22,019.	
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Stock option expense				
9 Other equity-based compensation				
10 Meals and entertainment				
11 Fines and penalties				
12 Judgments, damages, awards, and similar costs				
13 Parachute payments				
14 Compensation with section 162(m) limitation				
15 Pension and profit-sharing				
16 Other post-retirement benefits				
17 Deferred compensation				
18 Charitable contribution of cash and tangible property				
19 Charitable contribution of intangible property				
20 Charitable contribution limitation/carryforward				
21 Write-off of premium receivables				
22 Guarantee fund assessments				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization of acquisition, reorganization, and start-up costs				
27 Amortization/impairment of goodwill, insurance in force, and ceding commissions Stmt 27	18,307.	-18,307.		
28 Other amortization or impairment write-offs		5,515.		5,515.
29 Discounting of unpaid losses (section 846) (attach statement)	-1,653.	950.		-703.
30 Reduction of loss deduction (section 832(b)(5)(B))				
31 Depreciation				
32 Bad debt expense and/or agency balances written off				
33 Reserved for future use				
34 Corporate-owned life insurance premiums				
35 Purchase versus lease (for purchasers and/or lessees)				
36 Interest expense (attach Form 8916-A)				
37 Research and development costs				
38 Section 118 exclusion (attach statement)				
39 Other expense/deduction items with differences (attach statement) Stmt 27	-3,329.	5,105.		1,776.
40 **Total expense/deduction items.** Combine lines 1 through 39. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	61,647.	-6,737.	-48,322.	6,588.

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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	3,248,985,029.			3,248,985,029.
1b	Returns and allowances				
1c	Balance	3,248,985,029.			3,248,985,029.
2	Cost of goods sold	1,745,253,324.			1,745,253,324.
3	Gross profit	1,503,731,705.			1,503,731,705.
4	Dividends	105,240,423.			105,240,423.
5	Interest	23,291,332.			23,291,332.
6	Gross rents	1,047,657.			1,047,657.
7	Gross royalties				
8	Capital gain net income	3,304,955.			3,304,955.
9	Net gain or (loss) from Form 4797	19,822,373.			19,822,373.
10	Other income	49,892,769.			49,892,769.
11	Total income	1,706,331,214.			1,706,331,214.
12	Compensation of officers	6,915,565.			6,915,565.
13	Salaries and wages	169,997,944.			169,997,944.
14	Repairs and maintenance	155,763,430.			155,763,430.
15	Bad debts	26,073,254.			26,073,254.
16	Rents	4,491,124.			4,491,124.
17	Taxes and licenses	69,403,254.			69,403,254.
18	Interest	223,411,687.			223,411,687.
19	Charitable contributions	464,645.			464,645.
20	Depreciation	359,623,070.			359,623,070.
21	Depletion	466,005.			466,005.
22	Advertising	1,685,899.			1,685,899.
23	Pension, profit-sharing etc., plans	25,488,961.			25,488,961.
24	Employee benefit programs	26,047,486.			26,047,486.
25	Energy efficient commercial buildings deduction				
26	Other deductions	473,512,975.			473,512,975.
27	Total deductions	1,543,345,299.			1,543,345,299.
28	Taxable income before NOL & Spec. Deductions	162,985,915.	NONE		162,985,915.
29	NOL,Spec. deductions	107,818,289.		1.	107,818,290.
30	Taxable income	55,167,626.	NONE	-1.	55,167,625.

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		UGI Corporation	AmeriGas Propane, Inc.	AmeriGas Technology Group, Inc.	AmeriGas, Inc.	Ashtola Production Company	Eastfield International Holdings, Inc.	Energy Services Funding Corporation	Four Flags Drilling Company
		23-2668356	23-2786294	23-2861011	23-2716858	23-2101362	51-0385770	23-3099149	23-2178262
1a	Gross receipts or sales	1,337,739,648.							
1b	Returns and allowances								
1c	Balance	1,337,739,648.							
2	Cost of goods sold	807,902,853.							
3	Gross profit	529,836,795.							
4	Dividends								
5	Interest	7,048,753.	1,007,544.						
6	Gross rents	611,645.							
7	Gross royalties								
8	Capital gain net income		1,505,434.						
9	Net gain or (loss) from Form 4797								
10	Other income	-34,982,587.	-9,365,281.					6,676,736.	
11	Total income	502,514,606.	-6,852,303.					6,676,736.	
12	Compensation of officers	6,915,565.							
13	Salaries and wages	68,716,553.							
14	Repairs and maintenance	14,134,656.							
15	Bad debts							390,096.	
16	Rents	3,921,773.							
17	Taxes and licenses	12,052,393.	3,499,709.					763,458.	
18	Interest	109,948,550.						-2,618,169.	
19	Charitable contributions								
20	Depreciation	148,556,753.	5,447.						
21	Depletion	466,005.							
22	Advertising	600,532.							
23	Pension, profit-sharing etc., plans	2,012,161.							
24	Employee benefit programs	7,836,802.							
25	Energy efficient commercial buildings deduction								
26	Other deductions	161,899,228.	257,664.			1,287.		412,504.	
27	Total deductions	537,060,971.	3,762,820.			1,287.		-1,052,111.	
28	Taxable income before NOL & Spec. Deductions	-34,546,365.	-10,615,123.	NONE	NONE	-1,287.	NONE	7,728,847.	NONE
29	NOL,Spec. deductions								
30	Taxable income	-34,546,365.	-10,615,123.	NONE	NONE	-1,287.	NONE	7,728,847.	NONE

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		Homestead Holding Company	Newbury Holding Company	UGI Black Sea Enterprises, Inc.	UGI Energy Ventures, Inc	UGI Ethanol Development Company	UGI Europe, Inc.	UGI Hunlock Development Company	UGI International (Romania), Inc.
		51-0467618	30-0170818	23-2800542	71-0992456	23-2179048	23-3070112	23-3051491	23-2837401
1a	Gross receipts or sales						523,702,622.		
1b	Returns and allowances								
1c	Balance						523,702,622.		
2	Cost of goods sold						529,644,005.		
3	Gross profit						-5,941,383.		
4	Dividends						105,228,229.		
5	Interest		726.				16,001,988.		
6	Gross rents						524,543.		
7	Gross royalties								
8	Capital gain net income								
9	Net gain or (loss) from Form 4797								
10	Other income						-261,475.		
11	Total income		726.				115,551,902.		
12	Compensation of officers								
13	Salaries and wages						-767,523.		
14	Repairs and maintenance								
15	Bad debts								
16	Rents	8,776.	3,412.						
17	Taxes and licenses		61.				333,742.		
18	Interest	4,600,220.					18,420,708.		
19	Charitable contributions								
20	Depreciation						84,186.		
21	Depletion								
22	Advertising						75,403.		
23	Pension, profit-sharing etc., plans						57,053.		
24	Employee benefit programs						35,618.		
25	Energy efficient commercial buildings deduction								
26	Other deductions	3,361.	670.				-110,513,815.		
27	Total deductions	4,612,357.	4,143.				-92,274,628.		
28	Taxable income before NOL & Spec. Deductions	-4,612,357.	-3,417.	NONE	NONE	NONE	207,826,530.	NONE	NONE
29	NOL,Spec. deductions						101,597,941.		
30	Taxable income	-4,612,357.	-3,417.	NONE	NONE	NONE	106,228,589.	NONE	NONE

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		UGI LNG, Inc	UGI Penn HVAC Services, Inc	UGI Properties, Inc.	UGI Romania, Inc.	UGI Storage Company	UGID Holding Company	UGI Utilities, Inc	AmeriGas Propane Holdings, Inc
		51-0590685	23-1946160	23-2710207	23-2925615	32-0309503	51-0389590	23-1174060	83-4160550
1a	Gross receipts or sales	13,200,000.				14,857,175.		1,305,207,921.	
1b	Returns and allowances								
1c	Balance	13,200,000.				14,857,175.		1,305,207,921.	
2	Cost of goods sold					54,417.		512,302,998.	
3	Gross profit	13,200,000.				14,802,758.		792,904,923.	
4	Dividends								
5	Interest	2,497.				24,505.		-2,256,227.	1,972,209.
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								1,813,236.
9	Net gain or (loss) from Form 4797							-13,715.	
10	Other income	-13,110.		71,726.		6,181,310.		14,947,590.	60,095,481.
11	Total income	13,189,387.		71,726.		21,008,573.		805,582,571.	63,880,926.
12	Compensation of officers								
13	Salaries and wages	538,363.				351,224.		87,600,819.	
14	Repairs and maintenance	2,397,684.		198,587.		1,792,101.		136,208,654.	
15	Bad debts	8,409.						23,511,488.	
16	Rents							557,163.	
17	Taxes and licenses	265,712.		-38,565.		1,387,825.		28,795,456.	-2,994,269.
18	Interest							81,813,927.	
19	Charitable contributions					195,000.			
20	Depreciation	4,163,205.				827,165.		167,174,431.	
21	Depletion								
22	Advertising							1,009,964.	
23	Pension, profit-sharing etc., plans	27,695.				18,086.		20,180,249.	
24	Employee benefit programs	54,904.				35,853.		13,828,295.	
25	Energy efficient commercial buildings deduction								
26	Other deductions	1,203,603.		126,516.		782,268.		113,660,673.	273,343,346.
27	Total deductions	8,659,575.		286,538.		5,389,522.		674,341,119.	270,349,077.
28	Taxable income before NOL & Spec. Deductions	4,529,812.	NONE	-214,812.	NONE	15,619,051.	NONE	131,241,452.	-206,468,151.
29	NOL,Spec. deductions								
30	Taxable income	4,529,812.	NONE	-214,812.	NONE	15,619,051.	NONE	131,241,452.	-206,468,151.

Consolidated Schedules 1120 Page 1		Mountaineer Gas Company	Mountaintop Energy Holdings LLC	UGI Development Company	UGI Eliminations	United Valley Insurance Company PC	UGI PC Eliminations
		55-0521087	27-4543948	23-1650159		03-0338831	23-2668356
1a	Gross receipts or sales	292,535,910.		27,766,534.	-266,115,247.	90,466.	
1b	Returns and allowances						
1c	Balance	292,535,910.		27,766,534.	-266,115,247.	90,466.	
2	Cost of goods sold	141,981,187.		19,166,819.	-265,798,955.		
3	Gross profit	150,554,723.		8,599,715.	-316,292.	90,466.	
4	Dividends					12,194.	
5	Interest			149,297.	-703,480.	43,520.	
6	Gross rents				-88,531.		
7	Gross royalties						
8	Capital gain net income						
9	Net gain or (loss) from Form 4797	49,561.		19,772,812.			
10	Other income	671,846.		5,885,540.	-15,007.		
11	Total income	151,276,130.		34,407,364.	-1,123,310.	146,180.	
12	Compensation of officers						
13	Salaries and wages	11,361,567.		2,196,941.			
14	Repairs and maintenance			1,031,748.			
15	Bad debts	2,163,261.					
16	Rents						
17	Taxes and licenses	24,977,650.		495,237.		-135,155.	
18	Interest	11,949,931.			-703,480.		
19	Charitable contributions						
20	Depreciation	36,857,002.		1,954,881.			
21	Depletion						
22	Advertising						
23	Pension, profit-sharing etc., plans	3,151,407.		42,310.			
24	Employee benefit programs	4,149,110.		106,904.			
25	Energy efficient commercial buildings deduction						
26	Other deductions	30,995,321.	29,232.	1,609,582.	-419,830.	121,365.	
27	Total deductions	125,605,249.	29,232.	7,437,603.	-1,123,310.	-13,790.	
28	Taxable income before NOL & Spec. Deductions	25,670,881.	-29,232.	26,969,761.	NONE	159,970.	NONE
29	NOL,Spec. deductions		6,208,154.			12,194.	
30	Taxable income	25,670,881.	-6,237,386.	26,969,761.	NONE	147,776.	

BOOK III

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 1 – HANS G. BELL
UGI GAS STATEMENT NO. 2 – TRACY A. HAZENSTAB
UGI GAS STATEMENT NO. 3 – JILL E. WALTER
UGI GAS STATEMENT NO. 4 – VIVIAN K. RESSLER
UGI GAS STATEMENT NO. 5 – AMY M. KELLER
UGI GAS STATEMENT NO. 6 – JOHN F. WIEDMAYER

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI GAS STATEMENT NO. 1

HANS G. BELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 1

Direct Testimony of
Hans G. Bell

Topics Addressed: **Purpose of Testimony and Rate Filing Overview**
Need for Rate Relief

Dated: January 28, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Hans G. Bell. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI") as its President. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. As President, I am accountable for delivering the overall business performance to ensure adequate, efficient, safe, reliable, and reasonable natural gas and electric utility service to UGI's customers.

Q. What is your educational and professional background?

A. Please see my resume, UGI Gas Exhibit HGB-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit HGB-1 contains a list of those proceedings.

II. PURPOSE OF TESTIMONY AND RATE FILING OVERVIEW

Q. Please describe the purpose of your testimony in this proceeding.

A. My testimony will present an overview of the rate filing, including a brief explanation of the reasons for rate relief and an outline of the testimony of each witness in this proceeding. I will also address UGI's efforts to manage the affordability of service to customers with the need to continue to undertake critical safety improvements on its distribution system.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring UGI Gas Exhibit HGB-1. Also, I am sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI Gas in this proceeding and the subject matter of their testimony.

A. In addition to my testimony, the following witnesses are providing testimony in support of the Company's rate request:

Tracy A. Hazenstab (UGI Gas Statement No. 2) holds the position of Sr. Manager – Utility Rates for UGI Utilities, Inc. She addresses operating revenues and expenses and the revenue requirement model supporting the Company's proposed rate increase, UGI Gas Exhibit A (Fully Projected). Ms. Hazenstab also sponsors the revenue requirement models for the future and historic periods, UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic), respectively.

Jill W. Walter (UGI Gas Statement No. 3) holds the position of Director Operations – South Region at UGI Gas. Ms. Walter's testimony addresses UGI Gas's operations and natural gas distribution system. In addition, Ms. Walter discusses UGI Gas's Long-Term Infrastructure Improvement Plan ("LTIIP"), and the impact of the LTIIP and other initiatives on system performance, safety, and reliability, including an update on the Company's methane detection pilot that was agreed to in settlement of the 2025 Gas Base Rate Case at Docket No. R-2024-3052716. Also, Ms. Walter addresses UGI Gas's efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where UGI Gas or corporate predecessors once owned and/or operated manufactured gas plants in connection with gas utility operations.

Vivian K. Ressler (UGI Gas Statement No. 4) holds the position of Director – Utility Financial Planning & Analysis ("FP&A") at UGI. Ms. Ressler addresses the budgeting process and certain operating expense adjustments, as well as the Company's accounting for information technology costs.

Amy M. Keller (UGI Gas Statement No. 5) holds the position of Sr. Manager – Regulatory and Plant Accounting at UGI. Ms. Keller explains UGI Gas's accounting processes used to develop the Company's actual book accounting results, which are the basis for the Historic Test Year ("HTY") ended September 30, 2025. Ms. Keller also presents UGI Gas's rate base claim for the HTY, Future Test Year ("FTY"), and Fully Projected Future Test Year ("FPFTY"). Ms. Keller further addresses certain operating expense adjustments.

John F. Wiedmayer (UGI Gas Statement No. 6) holds the position of Senior Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports UGI Gas's claim for annual depreciation expense, and the accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic).

Vicky A. Schappell (UGI Gas Statement No. 7) holds the position of Sr. Manager, Capital Planning for UGI Gas. Ms. Schappell addresses capital expenditures and capital planning, including the planned plant in service expenditures for the FTY and FPFTY.

Dylan W. D'Ascendis (UGI Gas Statement No. 8) holds the role of Partner at ScottMadden Management Consultants. Mr. D'Ascendis presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity, and overall fair rate of return. Schedules and workpapers supporting Mr. D'Ascendis's findings are set forth in UGI Gas Exhibit B (Rate of Return).

Darin T. Espigh (UGI Gas Statement No. 9) holds the position of Sr. Manager – Natural Gas Tax Accounting. Mr. Espigh addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, and the repairs allowance.

Sherry A. Epler (UGI Gas Statement No. 10) holds the position of Senior Manager Tariff and Supplier Administration for UGI. Ms. Epler's testimony addresses the development

of the Company's HTY, FTY and FPFTY test year sales and revenues. In addition, Ms. Epler addresses several proposed tariff updates. Ms. Epler sponsors UGI Gas Exhibit E (Proof of Revenue) and UGI Gas Exhibit F (Current and Proposed Tariffs).

John D. Taylor (UGI Gas Statement No. 11) is a Managing Partner of Atrium Economics LLC. Mr. Taylor prepared and sponsors UGI Gas's fully allocated cost of service study. This study is contained in UGI Gas Exhibit D. The Allocated Cost of Service Study ("ACOSS") allocates the Company's cost of service associated with Commission jurisdictional operations to the Company's customer classes. Mr. Taylor also addresses the Company's proposed revenue allocation and rate design, along with proposed changes to the Company's definition of normal weather and renewal of the Company's Weather Normalization Adjustment ("WNA") pilot.

Brian J. Meilinger (UGI Gas Statement No. 12) is the Director – Customer Programs and Public Relations at UGI. Mr. Meilinger's testimony addresses the Company's efforts to provide affordable service. Mr. Meilinger also discusses the Company's updates to its WNA customer communications.

III. NEED FOR RATE RELIEF

Q. Please discuss UGI Gas's proposed rate relief request and provide an overview of the Company's proposals in this proceeding.

A. UGI Gas is requesting an increase in its annual base rate operating revenues of $99.368 million, or 8.05 percent on a total revenue basis, with a proposed effective date of March 29, 2026. The base rate increase requested in this filing utilizes a FPFTY ending September

30, 2027. UGI Gas continues to make substantial distribution system investments that are necessary to: (1) continue the accelerated replacement of aging gas plant infrastructure; (2) upgrade and improve system segments and modernize facilities; (3) serve new residential and commercial customers, including natural gas conversions; (4) install and upgrade supporting information technology systems; and, most importantly, (5) ensure the safety of the Company's employees, customers, the communities it serves, and its distribution system. Moving forward, these system improvements and investments will require the Company to continue its efforts to attract, recruit, train, and retain those professional, technical, and field-qualified personnel and resources necessary to implement, operate, and maintain those investments, and to attract capital at a reasonable cost. These investments are all necessary to grow and continue to maintain a safe and reliable distribution system and provide quality customer service. As compared to pre-FPFTY gross plant levels, UGI Gas is projecting an increase of approximately $468 million in gross plant through the FPFTY compared to the end of the FTY, and a total of $879 million in gross plant when compared to the end of the HTY. Based on this factor alone, UGI Gas's current rates will not provide it with a reasonable opportunity to earn a fair rate of return on its increased rate base investments.

Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1, UGI Gas's operations are projected to produce an overall return on rate base of 6.55%, which equates to a return on common equity of only 7.70% for the twelve-month period ending September 30, 2027. As explained by UGI Gas witness Dylan W. D'Ascendis (UGI Gas Statement No. 8), those returns are inadequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, those projected returns will continue to decline. This could potentially jeopardize UGI

Gas's ability to attract the capital needed to make investments that support operating a safe and reliable distribution system and enhance the reach and capacity of facilities that are required for system growth. Moreover, with its requested rate relief, UGI Gas will have the opportunity to earn a sufficient return on investments, serving as a needed source of capital to continue replacing older, more risk prone facilities, systems, and equipment, each of which is necessary to ensure continued system reliability, safety, and customer service performance.

Q. How have UGI Gas's expenses changed since its last base rate case?

A. UGI Gas has been very successful in managing its expenses, and projects only an approximate 1% increase in its overall Operations and Maintenance budget by the end of the FPFTY. The expense increases include wage and salary adjustments where necessary to maintain a productive and effective workforce, as well as increases in costs that are not within the Company's direct control, such as PUC assessments and other price increases for necessary products and services. UGI Gas continues to focus on efficient operations and has seen stable customer growth over time.

Q. Has the Company evaluated the impact of its proposed rate increase on average customer bills generally?

A. Yes. As shown in Table 1, below, the Company has evaluated the impact of its proposed rate increase on the average monthly bill of residential heating, commercial heating, and industrial customers.

Table 1 – Average Customer Bill Impact

Average Residential Heating Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
68.7 ccf	$113.64	$123.55	$ 9.91	8.7%

Average Commercial Heating Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
26.8 Mcf	$336.74	$358.17	$ 21.43	6.4%

Average Industrial Customer Bill Impact

Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
54.6 Mcf	$647.57	$688.65	$ 41.07	6.3%

The average customer monthly bill impacts set forth in Table 1, above, are fair and reasonable because UGI Gas will utilize the increase in distribution rates to support its ongoing provision of safe and reliable distribution service for its customers. The proposed customer charges also reasonably reflect cost-of-service principles, while considering the rate design principle of gradualism.

Q. Is the Company making any other key proposals in this general rate increase filing?

A. Yes. As required by the Joint Petition for Settlement in Docket No. R-2021-3030218, UGI Gas must address its WNA Pilot program in a case filed before January 31, 2026. As such, UGI Gas is proposing in this proceeding to extend and modify its WNA pilot for an additional five years, ending October 31, 2032. Additionally, the Company is proposing to establish Normal Heating Degree Days ("NHDD") based on a 10-year weather history for use in both its distribution rates and the calculation of the WNA. These proposals, as

well as the rate design and revenue allocation, are discussed in more detail in the testimony of John D. Taylor (UGI Gas Statement No. 11).

Q. Please describe UGI Gas's most significant accomplishments in recent years demonstrating its commitment to customer safety, service reliability, and cost-effective infrastructure investment.

A. UGI Gas will accomplish a major safety milestone in 2026, when it completes the retirement of all known cast iron on its distribution system. The Company also remains on track to replace all of its bare steel mains by 2041. Additionally, as discussed above, UGI Gas has maintained strong Operations and Maintenance ("O&M") cost control between the FTY and FPFTY, with only a 1% budgeted increase (excluding Gas Supply and Depreciation & Amortization expenses). This discipline is best reflected in four key drivers: (1) controlled salary costs, particularly in back-office functions; (2) minimal growth in health benefits expenses; (3) an improved uncollectible rate; and (4) strategic procurement efforts that optimized vendor pricing. Finally, the Company took significant voluntary steps to protect low-income customers from the recent Federal Government shutdown and its resulting impact on LIHEAP funding. The full range of the situation, its potential impacts, and the Company's response are described in the direct testimony of Brian J. Meilinger, UGI Gas Statement No. 12. However, UGI Gas's most critical actions included making an additional $500,000 contribution to Operation Share in fiscal year 2026 and suspending terminations for LIHEAP qualifying customers.

Q. What actions has UGI taken to assist customers having difficulty paying their bills in recent years?

A. Since 2020, UGI has donated more than $7.5 million dollars to Operation Share to support customers facing economic hardship that are struggling to pay their bills. For Fiscal Year 2026, alone, UGI has donated more than $1.5 million, including the $500,000 donated in response to the delay in the funding of LIHEAP.

Q. Is UGI committing to any other actions to support the affordability of service for its customers at this time?

A. Yes. As part of this case, UGI is committing to contribute $1,000,000 annually each year for fiscal years 2027 to 2029 to its Operation Share program. These annual donations will assist thousands of qualifying customers, who may receive up to $600 in assistance in paying their energy bills. This funding for Operation Share is a donation from UGI that is not recoverable from or included in rates paid by customers, similar in nature to the many other charitable donations and community giving made by UGI each year to support the communities it operates in. Examples of the charitable donations and community giving undertaken by UGI include annual donations of $52,000 to the American Red Cross and $182,330 to 25 local organizations through United Way.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT HGB-1

Hans G. Bell

Summary

Proven Energy Utility Executive with 29 years of gas & electric utility leadership experience including P/L accountability, transmission and distribution operations, engineering, asset integrity management, rate case / regulatory strategy, capital program management, customer service, and business development.

Experience

UGI Utilities, Inc., Denver, Pennsylvania

Utility President accountable for all aspects of business performance to ensure safe, reliable, and cost-effective natural gas & electric service for a utility serving more than 700,000 customers. Over a 12-year tenure at UGI Utilities, led the establishment of long-term infrastructure investment programs, led a 4-fold ramp up in capital investment to achieve infrastructure replacement objectives, developed internal & external capabilities and resources to execute the program, and guided the strategies needed to achieve return on investment. Consistently led team to deliver on key metrics including safety, reliability, customer service, and financial objectives.

President, UGI Utilities, Inc. *2020-present*

- Accountable for accountable for delivering overall business performance to ensure safe, reliable, and cost-effective natural gas and electric utility service
- Provides executive leadership for organization comprised of ~1,700 personnel including executives, technical professionals, and line workers engaged in gas & electric operations, engineering, financial management, rates, gas supply, environmental health & safety, capital program management, construction, and IT system implementation
- Delivers presentations to Board of Directors to secure approval of long-term strategy, annual plan, and major investments
- Maintains relationships among regulators, elected officials, customers, and trade allies
- Presents Utility segment business updates at investor conferences and meetings with shareowners

Chief Operating Officer *2017-2020*

- Consistently delivered upon increasing annual infrastructure replacement plans – on-time and on budget pipeline replacement program for 6 consecutive years
- Developed & implemented sustainability strategies into the business, including establishing methane emission reductions and integration of renewables and energy efficient technologies
- Implemented a safety culture enhancement program and initiated a Pipeline Safety Management System implementation plan
- Led delivery of a $70M pipeline of 10 miles x 24” pipeline, to serve major power plant, now UGI’s single largest customer
- Primary author of the UGI Long-Term Infrastructure Improvement Plan – a 5-year investment plan and strategy encompassing more than $1.25 Billion of safety & reliability improvements
- Achieved safety & reliability improvements including 27% reduction in hazardous leaks, 75% reduction in leaks scheduled for repair, 36% reduction in cast iron main break frequency, and consistent performance in excavation damage prevention

Vice President, Engineering and Operations Support *2013- 2017*

- Accountable for accelerated infrastructure replacement programs, capital budgeting contractor management, corrosion control, damage prevention, employee safety, engineering design, transmission & distribution integrity, regulatory compliance, training, and all related technical support functions.
- Accountable for planning and execution of annual cast iron / bare steel replacement program covering > 64 miles per year
- Primary author & regulatory witness for Long Term Infrastructure Improvement Plans, and annual asset optimization plans
- Primary witness providing written and verbal testimony to secure and increase the UGI Distribution System Improvement Charge which accelerated intra-rate case recovery of major safety & reliability investments
- Responsible for management and development of professional and technical support staff of over 110 employees
- Managed regulatory compliance activities with the PA Public Utilities Commission – Pipeline Safety Division

Nicor Gas, Naperville, Illinois

Over 17 years at Nicor Gas, a 2.1M customer gas utility, advanced through positions of increasing responsibility beginning at entry level through Managing Director of Engineering. During the AGL / Nicor merger served as functional lead for engineering & technical support on the merger integration team.

Managing Director, Engineering *2012-2013*

- Accountable for Engineering Design, Land Management, and System Planning supporting gas transmission, storage, and distribution operations spanning 11 states serving over 4.5 million customers
- Managed capital budgets of >$200M including budget development, variance reporting, and project prioritization
- Accountable for oversight of right of way acquisitions in advance of major pipeline projects
- Developed long term investment plans for infrastructure replacement, optimization, and growth

Assistant Vice President Engineering & Chief Engineer *2011- 2012*

- Accountable for all gas utility engineering support departments with over 50 professional and technical staff including Engineering Design, Transmission Integrity, Distribution Integrity, System Planning, Geographic Information Systems, Measurement, and Technical Services (Lab)
- Accountable for Transmission & Distribution Integrity Management compliance, audits, plans, program management, and project portfolio optimization.
- Accountable for Engineering Design and project management for distribution, storage, and transmission projects from initial scope, detailed design, cost estimates, sourcing, and contract negotiation
- Managed multiple interdisciplinary project teams executing complex multi-million-dollar storage and transmission projects
- Managed regulatory relationships with State (ICC) and Federal Pipeline Safety Agencies (PHMSA). Provided technical support to incident investigations
- Developed strategic approaches to addressing pipeline safety legislation including MAOP affirmation
- Developed engineering integration plans for AGL Resources– Nicor Gas merger including, organizational design, critical process mapping, accountabilities, budgeting, and staffing

General Manager System Integrity & Chief Engineer *2007 - 2011*

- Responsible for management of multiple departments including Engineering, Transmission Integrity, Distribution Integrity, System Planning, and Geographic Information Systems
- Responsible for development and management of infrastructure capital budgets of approximately $65 million
- Managed contracts with engineering consulting firms for pipeline design, construction, survey, and professional services
- Implemented a Distribution Geographic Information System including database design, data conversion of over 34,000 miles of distribution pipe, and deployment of a mobile GIS application to all front-line workers

Manager Engineering Design *2004- 2007*

- Responsible for managing departmental capital budget in excess of $20 million annually
- Provided project management oversight to pipeline projects from concept, feasibility, budgeting, approval, planning, design and implementation
- Maintained engineering consultant relationships and negotiated service contracts
- Implemented process improvements including development of Geographic Information System (GIS) based map distribution application
- Managed pipeline construction projects, negotiated construction contracts, resolved permitting issues, and delivered project approval presentations

Project Manager – Transmission Pipeline Integrity *2003 –2004*

- Responsible for development and implementation of pipeline integrity management program to maintain regulatory compliance with the Pipeline Safety Act of 2002
- Developed risk management program for prioritization of pipeline integrity assessments in high consequence areas
- Determined pipeline assessment project schedules including long term operating expense and capital budgets

Region Manager – Distribution *2001 – 2003*

- Manager responsible for construction and maintenance activities of gas distribution utility
- Managed projects involving main installations, service installations, and leak repairs
- Measured and tracked performance of 50 personnel against productivity and safety benchmarks
- Coordinated response to emergencies including gas leaks and pipeline breaks

Supervisor of Distribution Planning *2000 - 2001*

- Supervised staff of six engineers in distribution planning department
- Coordinated hydraulic modeling studies of 34,000-mile natural gas distribution system serving over 2 million customers
- Recommended capital improvement projects required to maintain uninterrupted reliable peak day service throughout entire natural gas distribution network
- Coordinated long range planning studies and forecasts used to develop capital budgets

Project Engineer *1996 –2000*

- Managed pipeline construction and maintenance projects, supervised inspectors and company maintenance crews
- Designed plans for installation and revision of gas distribution facilities
- Reviewed highway improvement plans and worked with state transportation engineers to resolve utility conflicts

Professional Activities & Affiliations

- Licensed Professional Engineer, State of Illinois, License # 62054443
- Director, Pennsylvania Chamber of Business & Industry 2023-present
- Director, Northeast Gas Association 2018- present (Chair 2025)
- Member, Society of Gas Operators – 2015 to present
- Member, Society of Gas Lighters – 2018 to present
- American Gas Association Bronze Award of Merit 2012
- Member, American Gas Association Leadership Council
- Chair, American Gas Association Distribution & Transmission Engineering Committee 2012 - 2013
- Co-chair of Southern Gas Association Distribution Engineering Committee 2007-2010

Education

Keller Graduate School of Management, Chicago, Illinois

***Master of Business Administration**, Graduated with Distinction, 2000*
Concentration in Finance

University of Illinois, Champaign, Illinois

***Bachelor of Science in Civil Engineering**, 1996*
Concentration in Construction Management

Wharton School, University of Pennsylvania, Philadelphia, Pennsylvania

Executive Development Program, 2017

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

P-2013-2398833 UGI Utilities, Inc. – Gas Division, Long Term Infrastructure Improvement Plan

P-2013-2398835 UGI Central Penn Gas Inc., Long Term Infrastructure Improvement Plan

P-2013-2397056 UGI Penn Natural Gas, Inc. Long Term Infrastructure Improvement Plan

R-2015-2518438 UGI Utilities, Inc. – Gas Division, Base Rate Case

P-2016-2537609 UGI Central Penn Gas, Inc., Distribution System Improvement Charge Cap Waiver

P-2016-2537594 UGI Penn Natural Gas, Inc., Distribution System Improvement Charge Cap Waiver

R-2018-3006814 UGI Utilities, Inc. – Gas Division, Base Rate Case

R-2024-3052716 UGI Utilities, Inc. – Gas Division, Base Rate Case

UGI GAS STATEMENT NO. 2

TRACY A. HAZENSTAB

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Gas Utilities, Inc. – Gas Division

Statement No. 2

Direct Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Revenue Requirement**
	Operating Revenues and Expenses

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Sr. Manager – Utility Rates. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Sr. Manager - Utility Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions. As part of these responsibilities, I am responsible for preparing and supporting the Company's revenue requirement models for this base rate filing, which is included as UGI Gas Exhibit A. I report directly to the Vice President – Rates and Regulatory Affairs of UGI.

Q. What is your educational background?

A. Please see my resume, UGI Gas Exhibit TAH-1, which is attached to my testimony.

Q. Please describe your professional experience.

A. Please see my resume, UGI Gas Exhibit TAH-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. Attached to my direct testimony is UGI Gas Exhibit TAH-1, which contains a list of proceedings in which I previously testified. Additional exhibits that I am sponsoring are described below.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's proposed revenue requirement. First, I provide an overview of the Company's revenue requirement exhibits for the historic year ended September 30, 2025 ("HTY"), future year ending September 30, 2026 ("FTY") and the fully projected future test year ending September 30, 2027 ("FPFTY") (Section III). Second, I present UGI Gas's ratemaking presentation for the FPFTY, including its revenues and operating expenses claims, and certain pro forma adjustments (Section IV). The Company's rate proposal in this case is predicated on its FPFTY exhibit, which demonstrates the need for a revenue increase of $99.368 million.

Q. What exhibits are you sponsoring in this proceeding?

A. In addition to UGI Gas Exhibit TAH-1 mentioned above, I am sponsoring UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Historic). I am

also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

III. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

Q. Please describe the principal accounting exhibits used to support UGI Gas's claims in this proceeding.

A. UGI Gas Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the FPFTY, including principal accounting exhibits, rate base claims, revenue at present rates, operating expense claims, taxes and certain *pro forma* adjustments. The FPFTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2027. UGI Gas Exhibit A (Future) is the principal accounting exhibit for the FTY, including certain *pro forma* adjustments. The FTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2026. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for the HTY, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-month period ended September 30, 2025. The future and historic schedules are provided as a benchmark for comparison with the FPFTY claim, which, as explained above, is the basis for UGI Gas's proposed revenue increase of $99.368 million.

Q. Please provide an overview of UGI Gas's principal accounting exhibits.

A. As noted above, UGI Gas's claims in this case are based on UGI Gas Exhibit A (Fully Projected). This presentation is comprised of four sections:

Section A summarizes UGI Gas's requested *pro forma* rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

Section B includes basic accounting data extracted from UGI Gas's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Gas's embedded cost of debt, year-end capital structure and overall claimed rate of return.

Section C provides the elements of UGI Gas's rate base claim and how each element of that claim is derived. UGI Gas's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.

Section D presents UGI Gas's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3 and were used to establish UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in UGI Gas Exhibits A (Future) and A (Historic)?

A. UGI Gas Exhibits A (Future) and A (Historic) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2026, and the fiscal year ending September 30, 2025, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing and supporting the FPFTY claims with actual and projected results from the FTY and HTY.

Q. What are the data sources for the UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic)?

A. This data is derived from UGI Gas's books and records as well as its capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the FTY. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the HTY.

IV. REVENUE REQUIREMENT FOR THE FULLY PROJECTED FUTURE TEST YEAR

Q. How is your discussion of UGI Gas's FPFTY revenue requirement presentation organized?

A. In Section IV.A., I present a summary of UGI Gas's FPFTY revenue requirement. In Section IV.B., I discuss UGI Gas's proposed rate base. In Section IV.C., I explain the determination of UGI Gas's revenues and operating expenses, depreciation, taxes other than income taxes, income taxes, and the gross revenue conversion factor.

A. FPFTY REVENUE REQUIREMENT SUMMARY

Q. How were the *pro forma* revenue increase and total revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 3, of UGI Gas Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate base). Lines 10-19 show the following items at present rates: *pro forma* revenues, *pro forma* expenses, taxes, taxes on the revenue increase, *pro forma* net operating income, and the calculated rate of return. Lines 20-23 show the increase in net operating income required to permit UGI Gas to earn the claimed overall rate of return of 8.20%. Application of the Gross Revenue Conversion Factor establishes the revenue increase shown on line 25 needed to generate the change in operating income. Column 4 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 8.20%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $99.368 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $1.334 billion and the annual level of operating revenues of $1.235 billion under existing rates. These figures are shown on line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected). Please also see the direct testimony of Hans G. Bell (UGI Gas Statement No. 1) for a discussion on certain considerations made by UGI Gas in establishing this revenue increase amount.

B. FPFTY RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY. Column 1 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim is $4.319 billion. Please see the direct testimony of Amy M. Keller (UGI Gas Statement No. 5) for a discussion of the rate base components.

C. FPFTY REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge ("DSIC"), and other *pro forma* annualizing and normalizing ratemaking adjustments. The net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 10).

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to operating expense claims.

A. UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2027. Section D of UGI Gas Exhibit A (Fully Projected) presents UGI Gas's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the appropriate test years ending September 30, 2026, and 2025, respectively. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing and supporting UGI Gas's FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Gas Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Gas's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of Sherry A. Epler (UGI Gas Statement No. 10) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $99.368 million on line 4 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 21, net income at proposed rates is $354.186 million. This represents a $71.369 million increase from the level under current rates ($282.817 million), as shown on line 21 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2027. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, column 3?

A. Yes. The derivation of the various column 3 revenue adjustments is included in UGI Gas Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-13, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-5 of Schedule D-3. Gas cost revenue adjustments for each customer class are shown on lines 6-10 and details of other revenue adjustments are shown on lines 11-13 of Schedule D-3. Details for each revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A)

and are discussed in the direct testimony of witness Sherry A. Epler (UGI Gas Statement No. 10). Another revenue adjustment, shown in Schedule D-5B, is sponsored by Darin T. Espigh (UGI Gas Statement No. 9). This adjustment, in the amount of $712,000, represents the amortization of the CIAC Tax Gross Up Regulatory Liability for interconnects. Regarding *pro forma* expenses, the derivation of the various adjustments is summarized individually on pages 1-2 of Schedule D-3, lines 16-55. The details for these adjustments are found in Schedules D-6 through D-31 and are sponsored by multiple witnesses, as described in the Table of Contents of UGI Gas Exhibit A (Fully Projected) and as listed on the header of each schedule.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted consistent with generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D.

Q. Were each of the *pro forma* adjustments reflected on Schedule D-3 also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated and then distributed to FERC accounts directly and presented on Schedule D-3 by major FERC account category.

Q. Schedule D-3 to UGI Gas Exhibit A (Fully Projected) shows an adjustment to Gas Costs in column 4. Please discuss this adjustment.

A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to increase purchased gas cost expense by the same amount as the gas cost revenue adjustment contained in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 10) and as shown on Schedule D-5, column 4, lines 7-11. UGI Gas recovers its purchased gas costs on a dollar-for-dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the decrease in purchased gas costs of $24.749 million equals the decrease in gas cost revenue as detailed by Ms. Epler. Thus, with this adjustment, purchased gas cost expense has no effect on the revenue requirement calculation.

Q. Please discuss the Salaries and Wages adjustment shown on Schedule D-7 in the amount of $942,000.

A. Schedule D-7, Column 4, shows a $942,000 increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 of Schedule D-7 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized employees that will take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increased

percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salary and wage increases are not reflected in the budget.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1, was determined using the allocations of labor and headcount for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Gas's budgeting process for the operating expense portion of salaries and wages.

Q. What adjustments are shown on Schedule D-8?

A. Schedule D-8 represents an adjustment in the amount of $2.363 million for environmental remediation expense. The adjustments are described in further detail in the direct testimony of Amy M. Keller (UGI Gas Statement No. 5).

Q. Please discuss Schedule D-10, which shows an adjustment for Rate Case Expense.

A. Lines 1 through 4 show the rate case expense that UGI Gas expects to incur in this case of $1.760 million. That amount is then normalized over a one-year period given the anticipated timing related to the next UGI Gas rate case. The budgeted amount of rate case expense in the FPFTY was $2.267 million. The budget was decreased by $537,000 as shown in Column 3, line 8 to reflect more current costs.

Q. What is the nature of the adjustments shown on Schedule D-11?

A. Schedule D-11 represents adjustments in the amount of ($330,000) for uncollectible expense. The adjustments are described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 4).

Q. Please explain the adjustment in the amount of $3.071 million shown on Schedule D-14.

A. Schedule D-14 represents an adjustment in the amount of $3.071 million for pension benefit expense. This adjustment is described in further detail in the direct testimony of Amy M. Keller (UGI Gas Statement No. 5).

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.

A. Schedule D-15, column 2, line 6, represents an adjustment in the amount of $876,000 for injuries and damages. This adjustment is described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 4).

Q. Please discuss the Customer Accounts Expense Adjustment on Schedule D-15 in the amount of $1.624 million.

A. The Company is required to pay interest on Customer Deposits that it holds in accordance with its tariff requirements. Further discussion on customer deposits can be found in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 4).

Q. Please explain the PUC Assessment Adjustment also shown on Schedule D-15 in the amount of $875,000.

A. This adjustment reflects an update to the budgeted PUC assessment expense in the amount of $875,000, column 2, line 10. Further discussion on this adjustment can be found in Ms. Ressler's testimony (UGI Gas Statement No. 4).

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment normalizes the amount of Universal Services Program ("USP") expense recovered through the Company's USP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this matter. The USP Rider recovers the Company's Customer Assistance Program ("CAP") Credits, Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its Operation Share program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment decreases the Company's budgeted expense by $1.416 million, to align the expense with the annualized amount of the Company's current USP Rider charge. As the USP Rider is a fully reconcilable rider, the USP adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to USP flows through to the revenue requirement calculation and into net income. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 10) for additional discussion of the USP Rider.

Q. Please explain the adjustment for Energy Efficiency and Conservation ("EE&C") Programs shown on Schedule D-19.

A. As with the PGC and USP Rider adjustments discussed above, this adjustment in the amount of $(340,000) aligns the amount of EE&C expense with the EE&C Rider charge (based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Legal and Consulting, Combined Heat and Power, and other Costs associated with the Company's Energy Efficiency and Conservation Program. This adjustment decreases the Company's budgeted expense to align with the annualized amount of the Company's current EE&C charge. As the EE&C Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation and into net income. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 10) for additional discussion of the EE&C Rider.

3. Depreciation Expense

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Gas's depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 6).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Gas witness Mr. Wiedmayer (UGI Gas Statement No. 6) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of ($231,000) set forth on Schedule D-21, page 2, column 3, line 64, annualizes budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service (as of the end of the FPFTY). This schedule also shows a decrease to the net negative salvage amortization of $1.197 million. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $170.518 million (as shown on Schedule D-3, page 2, column 13, line 53).

4. Taxes Other Than Income Taxes

Q. Please describe the taxes other than income adjustments in the amount of $950,000 shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7. This produces an adjustment to the amount of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax ("SUTA") expense in the total amount of $75,000. The calculation of these adjustments is shown in more detail on Schedule D-32. The other components of this schedule are supported in the testimony of Darin T. Espigh (UGI Gas Statement No. 9). In addition, Schedule D-31 includes an adjustment in the amount of $875,000 for the PUC Assessment, as described previously in my testimony.

5. Income Taxes

Q. What is the purpose of Schedules D-33 and D-34?

A. These schedules show the derivation of the Company's pro forma income tax expense claim, including the normalization of the effects of accelerated tax depreciation, as discussed in the direct testimony of Darin T. Espigh (UGI Gas Statement No. 9).

6. Gross Revenue Conversion Factor

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Dylan W. D'Ascendis (UGI Gas Statement No. 8). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue and to recognize the additional state and federal income taxes attributable to the proposed rate increase.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT TAH-1

Tracy A. Hazenstab
Sr. Manager – Utility Rates

Work Experience:

2024 – Current	Sr. Manager – Utility Rates UGI Utilities, Inc., Denver, PA
2008 - 2024	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony – Pennsylvania Public Utility Commission:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2019 UGI Electric EEC Phase III Petition:	Docket No. R-2019-3004144
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
2021 UGI Gas Base Rate Proceeding:	Docket No. R-2021-3030218
2022 UGI Electric Base Rate Proceeding:	Docket No. R-2022-3037368
2023 1307(f) Proceeding:	Docket No. R-2023-3040290
2024 UGI Gas EEC Phase II Petition:	Docket No. R-2024-3048418
2024 UGI Electric DSP V Petition:	Docket No. R-2024-3049343
2024 UGI Gas Book 2 Proceeding:	Docket No. R-2024-3048828
2025 UGI Gas Base Rate Proceeding:	Docket No. R-2024-3052716

Previous Testimony – Maryland Public Service Commission:

Purchased Gas Adjustment/Annual Cost Adjustment Hearing:

2008 Hearing:	Case Number 9511(c)
2009 Hearing:	Case Number 9511(d)
2010 Hearing:	Case Number 9511(e)
2012 Hearing:	Case Number 9511(g)
2014 Hearing:	Case Number 9511(i)
2015 Hearing:	Case Number 9511(j)
2016 Hearing:	Case Number 9511(k)
2017 Hearing:	Case Number 9511(l)
2018 Hearing:	Case Number 9516(a)
2019 Hearing:	Case Number 9516(b)
2020 Hearing:	Case Number 9516(c)

Assisted in Preparing – Pennsylvania Public Utility Commission:

2009 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2008-2079675
2009 UGI Gas Rate Case (former North Rate District):	Docket No. R-2008-2079660
2011 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2010-2214415
2016 UGI Gas Rate Case (former South Rate District):	Docket No. R-2015-2518438
2017 UGI Gas Rate Case (former North Rate District):	Docket No. R-2016-2580030
2018 UGI Electric Rate Case	Docket No. R-2017-2640058
2019 UGI Gas Rate Case	Docket No. R-2018-3006814
2020 UGI Gas Rate Case	Docket No. R-2019-3015162

Education:

B.A. in International Politics, Pennsylvania State University

UGI GAS STATEMENT NO. 3

JILL E. WALTER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

Statement No. 3

Direct Testimony of
Jill E. Walter

Topics Addressed: Gas Safety and Operations

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jill E. Walter. My current business address is 2121 City Line Ave Bethlehem, PA 18107.

Q. By whom are you employed and in what capacity?

A. I am employed as the Director of Operations - South Region by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two (2) operating divisions, the Gas Division ("UGI Gas" or the "Company) and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit JEW-1 to my testimony.

Q. What are your responsibilities as Director of Operations - South Region?

A. As Director of Operations - South Region, I am accountable for over 400 individuals including management, clerical, and field technicians that operate and maintain the Company's gas transmission and distribution system.

Q. Have you presented testimony in proceedings before the Commission?

A. No, I have not presented testimony in any proceedings before the Commission.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the following topics: (1) natural gas operations; (2) regulatory compliance; (3) system safety and reliability; (4) leak reductions and emergency response; (5) safety and training initiatives; and (6) environmental programs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibit JEW-1. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

II. NATURAL GAS SYSTEM OPERATIONS

Q. Please provide an overview of the Company's distribution system.

A. UGI Gas provides service to more than 700,000 residential, commercial, and industrial customers located in 45 of Pennsylvania's 67 counties and spanning more than 700 municipalities. As of September 30, 2025, the Company operates more than 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains in the Commonwealth of Pennsylvania.

Q. Please describe UGI Gas's operations centers and support facilities.

A. UGI Gas has operations centers and support facilities throughout its service territory. Additionally, UGI Gas has a stand-alone centralized training center facility ("Learning Center") in Reading, PA, which includes a "safety town" for real-life indoor and outdoor training inclusive of leak pinpointing and investigation, a separate welding and tapping center, a safety lab, a service lab, a measurement and regulation lab, and a construction and maintenance lab. The UGI Gas Learning Center supports Operator Qualification training for both UGI Gas employees as well as contractors.

Q. How does UGI Gas staff its operations?

A. UGI Gas relies upon a mix of employees and contractor resources for its capital, operations, and maintenance programs to accomplish many of its initiatives, including gas main and service replacement and installation, roadway and landscape restoration, leak repairs, meter reading, new business activities, and general system operation and maintenance. Further, UGI Gas's parent company, UGI Corp., provides management, administrative, and support services (*e.g.*, executive management, human resources, legal, finance, accounting, procurement, treasury, IT, and corporate governance).

III. REGULATORY COMPLIANCE

Q. What regulations govern the safe transportation of natural gas transmission and distribution pipelines?

A. UGI Gas is subject to the minimum federal pipeline safety regulations in 49 CFR § 192 - Transportation of Natural and Other Gas by Pipeline ("Part 192"). The Company must

also follow the applicable state pipeline safety requirements found in Pennsylvania Title 52, Chapter 59 - Gas Service and Hazardous Liquid Service ("Chapter 59"). Pennsylvania natural gas pipeline safety regulations found in Chapter 59 of the Commission's regulations generally follow the Part 192 regulations.

Q. What are the regulatory topics included in Part 192 regulations?

A. Part 192 covers all aspects pertaining to the design, construction, operation, and maintenance of natural gas pipelines owned and operated by the Company. Federal natural gas pipeline safety regulations mandate that Operators have procedures and processes touching upon the following:

- Design and Construction Standards
- Operation and Maintenance Procedures
- Emergency Plans
- Integrity Management Plans
- Damage Prevention Plans
- Public Awareness Programs
- Control Room Management Plans

Q. How has the Company complied with these regulations?

A. UGI Gas has several plans and procedural manuals in place to address all required regulations found in Part 192. Due to the requirements found in Part 192, specifically Subpart M which promulgates the maintenance requirements in Part 192, UGI Gas performs a multitude of safety checks annually across its distribution system to maintain system safety and reliability.

Q. Can you provide examples of compliance safety checks UGI Gas performs annually on its distribution system to comply with Part 192?

A. The Company's Gas Operations personnel perform several activities to comply with applicable Part 192 regulations as well as internal Company procedures. Some of these activities include, but are not limited to, the following:

- Pipeline Leak Surveys and Patrols
- Valve Maintenance and Inspection
- Regulator Station Inspection and Maintenance
- Service Line Leak Survey and Meter Inspection
- Atmospheric Corrosion Inspection
- Cathodic Protection Inspection and Maintenance
- Odorant Intensity Inspection
- Transmission Integrity Management Assessments

The activities mentioned above are performed throughout the year and in certain situations, multiple times on the same distribution or transmission asset annually. This work also requires significant work planning/scheduling and record retention management. Throughout the year, the Company's Gas Operations personnel perform several thousand safety checks across its distribution system.

Q. Does the Company undertake any voluntary actions that exceed federal requirements found in Part 192?

A. Yes. UGI Gas's plans and procedures exceed federal safety standards in a number of areas. Additionally, UGI Gas voluntarily adopted and implemented programs identified as industry wide best practices. One such example includes UGI Gas's implementation of American Petroleum Institute ("API") Recommended Practice 1173 – Pipeline Safety Management Systems ("PSMS"). UGI Gas's PSMS program is still in development and continues to work toward full implementation in order to promote an enhanced safety

culture and provide safe and reliable natural gas service to its customers. In FY26, the Company is developing formal processes related to incident investigation and management of change in accordance with the standard as well as formal PSMS training within the organization. In addition, the Company completed a Safety Culture Assessment in 2025 to understand opportunities to improve safety.

In other situations, UGI Gas has elected to implement voluntary actions that arise from national events or recommendations by the National Transportation Safety Board ("NTSB") and other governmental agencies where it believes that doing so will allow it to provide safer and/or more reliable service to its customers. As noted in the Company's prior base rate case testimony at Docket No. R-2024-3052716 ("2025 Rate Case"), an example of this voluntary compliance relates to UGI Gas's evaluation of over-pressurization protection ("OPP") utilized on its low-pressure systems. As an update to this prior testimony, as of September 5, 2025, of the 73 stations identified that were not compliant with the additional OPP that was recommended by the NTSB, all of them have been addressed through the installation of supplemental OPP, station abandonment, or regulator station replacement.

Q. Does the Company have integrity management plans?

A. Yes, the Company maintains a Transmission Integrity Management Program ("TIMP") and Distribution Integrity Management Program ("DIMP") and as mandated in 49 C.F.R. § 192, Subpart O – Gas Transmission Pipeline Integrity Management, and Subpart P – Gas Distribution Integrity Management.

Under Subpart O, UGI Gas must continually identify threats to its pipelines in high consequence areas ("HCAs"), moderate consequence areas ("MCAs"), and other designated areas along transmission lines to determine the risk posed by any identified threats. UGI Gas also must schedule and perform integrity assessments to address all applicable threats, collect information about the condition of the pipelines, and take risk reduction actions to minimize and mitigate applicable threats.

Under 49 C.F.R. § 192, Subpart P, operators of gas distribution pipelines are mandated to gather information regarding their distribution pipelines and identify and evaluate relevant threats to their distribution systems. Operators are also required to assess and prioritize risks associated with the distribution system, implement accelerated action aimed at mitigating the risks of pipeline failures, and assess the effectiveness of these actions. Furthermore, operators must establish and execute a process for the regular review and enhancement of their programs, as well as report their findings to regulatory authorities. Unlike TIMP, DIMP encompasses the entire distribution system rather than focusing solely on pipelines located in select areas along transmission lines. This is due to distribution pipelines being predominantly situated in urbanized, densely populated regions to supply gas to these communities.

Q. Does the Company train and qualify its field personnel prior to performing operations and maintenance activities on natural gas pipelines?

A. Yes, UGI Gas maintains an Operator Qualification Plan ("OQ Plan") complying with the requirements of 49 CFR § 192, Subpart N. The OQ Plan establishes requirements for and management of qualifications for pipeline personnel who perform covered tasks on a

pipeline. Pipeline personnel are trained and qualified under the tasks needed to perform their various work activities on a UGI Gas pipeline. Covered tasks ensure internal and external pipeline personnel are educated, tested, and competent to perform specific natural gas activities on UGI Gas's distribution system. UGI Gas's OQ Plan was updated to incorporate industry standard ASME B31Q tasks effective December 8, 2025, and includes over 160 unique covered tasks, which ensure internal and external pipeline personnel are educated, tested, and competent to perform specific natural gas activities on UGI Gas' distribution system.

Additionally, UGI Gas is implementing a new OQ management system to track employee and contractor qualifications compliance. This system will provide digital access to OQ records. One of the key advantages of the new system is the ability for supervisors or inspectors to scan an employee or a contractor's QR code while in the field to view their OQ record status.

IV. SYSTEM RELIABILITY AND SAFETY

Q. Please describe the physical composition of UGI Gas's distribution system.

A. Due to its long-term operation, the Company's distribution system includes a mixture of pipeline materials indicative of the industry's technological advancement over time. Cast iron mains historically were found in the oldest parts of the system. UGI Gas, and the industry in general, then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include various types and compositions of polyethylene ("PE") and coated steel piping. Overall, approximately ninety percent (90%)

of UGI Gas's distribution mains consist of contemporary materials, which UGI Gas defines as cathodically protected steel and modern plastic. UGI Gas's natural gas distribution system has the highest percentage of contemporary mains among major natural gas distribution companies in Pennsylvania. Additionally, as of December 31, 2025, UGI Gas only has approximately 3 miles of cast iron main left on-system.

Q. Please discuss the Company's actions to improve and enhance its distribution system.

A. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis pursuant to Commission-approved Long Term Infrastructure Improvement Plans ("LTIIP"). The Company's Initial LTIIP[1], Second LTIIP[2], and the first year of the Third LTIIP have resulted in UGI Gas successfully removing more than 802 miles of main over the 11-year period from 2014 to 2025 including 99% of its total cast iron mains and 48% of its total bare steel/wrought iron mains. UGI Gas continues to invest in improving and modernizing its distribution facilities serving customers throughout the Company's service territory. The Company filed its Third LTIIP on August 16, 2024, and this plan was approved by the Commission on December 5, 2024, at Docket No. P-2024-3050769. During the 12-month period from January 1, 2025, through December 31, 2025, the Company has exceeded its Third LTIIP estimate by

[1] On December 12, 2013, each of UGI Gas's three predecessor natural gas distribution companies filed Petitions, and received Commission approval, for LTIIPs at Docket Nos. P-2013-2398833, P-2013-2397056, and P-2013-2398835 (collectively referred to as the "Initial LTIIP"). In the Initial LTIIP, the Company identified its plan to replace all its cast iron main over the 13-year period ending in February 2027 and all of its bare steel and wrought iron main over the 28-year period ending September 2041. The Initial LTIIP period ended on December 31, 2019.

[2] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Petition filed on August 21, 2019) (the "Second LTIIP"). The Second LTIIP builds off the significant acceleration in the rate of infrastructure repairs, improvements, and replacements (including the accelerated replacement of cast iron and bare steel pipe) that was achieved by the Initial LTIIP and reflects even further acceleration.

replacing approximately 71 miles of total cast iron, bare steel, wrought iron, and priority plastic mains compared to the Third LTIIP's plan of 50-60 miles. Additionally, DSIC-eligible capital placed into service in calendar year ("CY") 2025 totaled approximately $330 million compared to the Third LTIIP's plan of $298.5 million. In addition to main replacements in the Third LTIIP, the Company is pursuing other infrastructure initiatives, including replacing service lines, meter sets, valves, and farm taps, as well as addressing safety upgrades relating to measurement and regulation facilities (e.g., making improvements to over-pressure protection equipment) and remediating mechanical tees. Additionally, the Company outlined a plan for replacement of priority plastic, which includes plastic installed between 1965 and 1985. The Company retired approximately 8.5 miles of priority plastic in calendar year 2025. These initiatives will make UGI Gas's system safer and more reliable. Continuing UGI Gas's infrastructure replacement program as outlined in its Third LTIIP will allow the Company to provide safe and reliable service both now and into the future.

Q. How does UGI Gas prioritize its pipeline replacement projects?

A. In 2019, UGI Gas began using the Data-Driven risk model ("DDRM"). The DDRM is a quantitative model incorporating leak repair data, incident data, and asset population data to calculate a risk index score for facility groupings referred to as Asset Threat Groups ("ATGs"). The DDRM is utilized in conjunction with the Subject Matter Expert ("SME") driven risk model in order to validate DDRM results by incorporating SME input.

The DDRM provides a quantitative basis for evaluating risk and creates a stable foundation for comparing year-over-year changes because of the consistent quantitative

underpinning utilized. Finally, the DDRM facilitates evaluation of other risk mitigation approaches, including additional operations and maintenance, leak survey and damage prevention measures.

Q. What are the Company's current goals for main replacement?

A. UGI Gas is on track to replace all its cast iron main no later than February 2027, consistent with its initial completion plan and prior commitments. Further, the Company is on track to complete its bare steel and wrought iron main replacement no later than September 2041, also consistent with its initial completion plan. Specifically, to maintain a pace of replacement that would achieve these objectives, the Company's Third LTIIP established the objective of replacing between 60 and 70 miles of main in calendar year 2026 with an increase to 75 to 85 miles in calendar year 2027. As part of its mileage identified in calendar year 2027, the Company is planning an abandonment of a large section of a wrought iron and bare steel line in the northern part of the Company's service territory due to corrosion. This project will retire approximately 15 miles of high pressure wrought iron and bare steel. The Company plans to return to replacing 60 to 70 miles of main in CY28 and CY29.

Q. What results has UGI Gas achieved in the first year of its Third LTIIP?

A. The Company replaced or retired approximately 71 miles of main in 2025 including 23 miles of cast iron, 40 miles of bare steel, and 8 miles of vintage plastic. In addition, the Company installed 14,230 excess flow valves. The Company also replaced 11,651

services in 2025, 7,208 of which included meter sets that were moved from indoors to outdoors. The Company plans to continue replacing 10,500 to 12,500 services per year.

Q. What is UGI Gas's projection of its replacement and betterment plant in service for the future test year ("FTY") and the fully projected future test year ("FPFTY")?

A. For the FTY, the replacement and betterment budget reflects $311.5 million plant in service. The FPFTY plant placed in service for replacement and betterment is budgeted to be $383.6 million. For more detail on the Company's budgeting process related to all planned capital activities, please refer to the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 7).

Q. What is the Company's basis for showing a further increase in plant placed in service in the FTY and FPFTY?

A. Foremost, the Company's annual plant additions related to replacement and betterment activities increased nearly $63 million over the 2021-2025 period, from $230 million in 2021 to $293 million in 2025. The Company anticipates that the cost of its replacement and betterment work will continue to increase through the FPFTY due to a number of different elements. The Company is further accelerating the number of miles it will accomplish in the FTY and FPFTY and has expanded work done to address safety upgrades and improvements that are not exclusively mileage-based replacements, such as meter moveouts, system reinforcement projects and regulator station rebuilds. In addition, the Company's piping projects include larger diameter bare steel pipes, and a greater focus on priority plastic in the FPFTY. For these reasons, UGI Gas's budget for the FTY and the

FPFTY reflects increased plant additions beyond the amount that the Company had accomplished during the HTY.

Q. Please discuss the Company's ongoing plans to move its indoor meter facilities outdoors.

A. UGI Gas is working to have all meters located outside by 2034 as required by the Commission's regulations at 52 Pa. Code 59.18, with limited exceptions as allowed by code. UGI Gas is taking a risk-based approach, while keeping efficiency in mind, to prioritize meters being moved outside based on the service line attributes and their associated risks and whether these services are attached to a main that will require replacement prior to 2034. As of October 1, 2025, the Company had a population of 84,554 meters inside customer's homes or businesses. UGI Gas plans to move approximately 10,500 meters outside per year or 31,500 meters between the HTY and FPFTY.

V. LEAK SURVEYS, LEAK REDUCTIONS, EMERGENCY RESPONSE AND METHANE DETECTORS

A. Leak Surveys

Q. Please discuss UGI Gas's efforts to identify, manage, and reduce system leaks.

A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system on an ongoing basis to evaluate corrosion and leak identification and resolution performance, track emergency response, and pursue damage prevention – all of which will drive improvements in employee and public safety. As a part of its DIMP,[3] UGI Gas regularly

[3] 49 C.F.R. § 192.1007.

re-assesses system risks and leak trends to determine if additional or accelerated actions are required to further reduce system leaks.

Q. How does the Company perform leak surveys of its distribution system assets?

A. UGI performs both walking and mobile leak survey activities on its mains and services. UGI completes these activities using approved equipment as outlaid in the Gas Operations Manual (GOM 70.10.10). Minimum frequencies for leak surveying by material type or location are also listed in the Gas Operation Manual. UGI completes these surveys at least at the minimum required cycles with a combination of internal and external resources.

Q. Please describe the Company's leak survey practices for its priority plastic pipe.

A. Priority plastic installed in the UGI Gas system contains DuPont Aldyl-A plastic pipe, which can be susceptible to failures over time dependent upon local environmental conditions and installation practices. The total length of priority plastic mains installed on UGI Gas's distribution system between the years of 1965 and 1985 is approximately 1,100 miles. Current leak survey frequencies for this asset population are generally on a 5-year cycle in line with federal regulations, although UGI Gas typically performs these surveys on a 4-year cycle. Starting with the Calendar Year 2026 leak survey cycle, UGI Gas will perform accelerated leak surveys on an annual basis for its priority plastic mains. Importantly, this data feeds into the Company's DIMP for evaluation, risk ranking, and replacement prioritization.

Q. How has the Company implemented Advanced Mobile Leak Detection ("AMLD") Technology to date?

A. UGI Gas began its initial pilot of AMLD in 2021. The Company purchased one AMLD device and subsequently installed it on a Company vehicle. During the initial phase, the vehicle was driven along 445 miles of main in the Northern district. In subsequent years, UGI Gas continued to pilot this unit and other competing AMLD technologies within its service territory to aid in the analysis and development of its AMLD program. In CY25, UGI Gas laid forth the plan to start the execution of AMLD work in the system starting in CY26.

Q. Can you describe the results of the Company's AMLD pilots?

A. Yes. The pilot resulted in the following learnings:

- AMLD technology can survey a much wider dynamic range than conventional Cavity Ring-Down Spectroscopy ("CRDS") and Tunable Diode Laser Absorption Spectroscopy ("TDLAS") methods.
- AMLD technology allowed UGI Gas to perform mobile main-line leak survey at speeds five to ten times greater than traditional main line survey.
- AMLD identified existing/known leaks 100% of the time on the routes surveyed. 81 existing leaks were found along with 64 new system leaks.
- For 208 confirmed underground indications, 10% of the leaks found with the AMLD equipment represented around 75% of the total emissions, which prove the technology is effective at finding very low level leaks.
- This technology can undergo rapid deployment during emergencies/special surveys to ensure system resiliency (e.g. earthquake, post-flooding, or incident response.)

Q. What are UGI Gas's long-term plans for AMLD Technology?

A. In CY26, UGI Gas will utilize the Company-owned AMLD device to survey between 600 and 1,200 miles of main across its territory, equating to approximately 5-10% range of the drivable miles. The CY26 work will be done in conjunction with traditional leak survey methods which are currently still required to meet UGI Gas's compliance activity. The main driver of the work in CY26 will be data collection to share with the Commission's Safety Division to develop an approach that appropriately incorporates AMLD in future years to fulfill UGI Gas's leak survey regulatory obligations. The additional information gained from this technology will identify new environmental risk reduction opportunities while also being leveraged within UGI Gas's DIMP to provide additional knowledge on the asset populations contained within the DIMP.

B. Leak Reductions

Q. How does UGI Gas classify leaks?

A. UGI Gas uses a standardized leak classification system consistent with general industry protocols. Specifically, underground leaks are classified as 'A,' 'B,' and 'C.' Class 'C' leaks are deemed hazardous, and repair work is undertaken immediately. Class 'B' leaks are non-hazardous at the time of detection but justify a scheduled repair. Pursuant to UGI Gas's practice, Class 'B' leaks must be repaired or cleared within one calendar year, but no later than 15 months from the date of the latest Class 'B' leak classification. UGI Gas has been focused on continuous improvement for Class 'B' leak repairs. To that end, the Company repaired 98.2% of Class 'B' leaks within six months of classification in Fiscal Year 2025. These accelerated repairs reduced the leak hazards as well as methane

emissions. Class ‘A’ leaks are deemed non-hazardous and are monitored for changes in severity.

In December 2023, UGI Gas established formal classifications and procedures for aboveground leaks on UGI Gas owned facilities. Prior to this, UGI Gas did not classify aboveground leaks. These aboveground leaks are classified as Class ‘G’ and ‘H.’ Class ‘G’ leaks are defined as a minor escape of gas from aboveground UGI Gas piping or related gas facilities that is in a location that does not endanger the public and should be repaired or cleared within five calendar years, not to exceed 63 months from the date of the latest Class ‘G’ leak classification. Class ‘H’ leaks are defined as an unintentional escape of gas from aboveground UGI Gas piping or related gas facilities that requires immediate repair or make safe action.

Q. How have UGI Gas’s system leaks improved since 2018?

A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This is directly attributable to its prioritization and aggressive replacement of leak-prone mains, services, and other assets. As Table 1 below demonstrates, since 2018, Class ‘C’ leak repairs have decreased by 59.9%, Class ‘B’ leak inventories have decreased by 76.0%, and Class ‘A’ leak inventories have decreased by 52.3%.

Table 1. Leak Inventories & Repairs

	Calendar Year 2015	Calendar Year 2025	Percent Change
C Leak Repairs	1,953	783	59.9% decrease
B Leak Inventory	816	196	76.0% decrease
A Leak Inventory	4,877	2,327	52.3% decrease

C. Emergency Response

Q. Please discuss UGI Gas's performance in the area of emergency response.

A. UGI Gas performs exceptionally well in the timely response to emergency notifications/calls. For the Fiscal Year ended September 30, 2025, 99% of the time, a first responder arrived on the premises within 45 minutes (or less) of receipt of an emergency call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage internal field and supervisory resources to provide emergency response coverage 24-hours per day, 365 days per year. UGI Gas sets performance goals on a 45-minute response, which is more stringent than the benchmark response time as defined by the Commission's Safety Division.[4] Moreover, for Fiscal Year 2025, 99.8% of the time a UGI Gas first responder arrived onsite within one hour of the emergency call. UGI Gas also had an average emergency dispatch time of only 2.95 minutes for Fiscal Year 2025.

[4] The Commission's Bureau of Audits issued a Management and Operations Audit Report of the Company in October 2019 (at Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236), which stated:

> The PUC Gas Safety Division defines acceptable emergency dispatch and response times as 15 minutes and 60 minutes, respectively. However, UGI has established a more stringent 45-minute emergency response key performance indicator of 97.8%. (Audit Report, p. 41).

D. Methane Detectors

Q. Provide a summary of UGI Gas's efforts to install in-home methane detection devices pursuant to the Commission-approved Settlement in the 2025 Rate Case.

A. UGI Gas is piloting the use of in-home methane detection devices as an additional layer of protection for natural gas customers. The initiative began in FY 2026 (ending September 30, 2026), and will continue through the FPFTY. This initiative is designed to evaluate the effectiveness of commercially available methane detectors in providing early warning of potential gas leaks within customer homes. The pilot will allow UGI Gas to assess device performance, installation considerations, customer engagement, and the overall impact on safety outcomes. By proactively evaluating this technology, UGI Gas aims to determine whether broader deployment could enhance public safety, reduce response times, and further strengthen the Company's comprehensive approach to leak detection and mitigation.

UGI Gas is also testing cellular and LoRaWAN remote communication as well as non-communication units. UGI Gas has deployed ~100 units as of the end of CY25. These units have been distributed to Company employees that are UGI Gas customers to act as Natural Gas Safety Ambassadors for this technology. After achieving learnings for the pilot, UGI Gas will shift to customer-focused education efforts in CY 2026. UGI Gas will look to add a dedicated Natural Gas Detector safety page to its website and also add a Natural Gas Safety section to its Energy Efficiency and Conservation website where customers can purchase Natural Gas Detectors that UGI Gas has ensured are UL 1484 approved.

VI. SAFETY AND TRAINING INITIATIVES

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. In 2025, UGI Gas renewed its commitment to safety with its stand "Everyone and everything is always safe" to clearly declare who we are and how we operate. This stand reinforces safety as a core value that guides every decision, action, and interaction across the organization for our employees, customers, contractors, communities and our assets. It reflects UGI Gas's commitment to proactive risk management, disciplined operational practices, and a culture of accountability where safety is never compromised. By embedding this stand into daily operations and leadership expectations, UGI Gas continues to strengthen a consistent Company-wide approach to safe, reliable service. In addition, UGI Gas has advanced several initiatives to further develop its safety culture and drive sustainable improvements in safety performance. In FY26, UGI Gas will replace its current telematics and in-cab driver coaching system and in vehicle monitoring equipment that will further enhance and develop its safe driving program through intentional supervisory coaching of "events" triggered by the system, as well as positive recognition of safe defensive driving maneuvers. In FY26, the Company will conduct training on the new system for its drivers, supervisors, and managers. Through FY26, the Company will evaluate the system's full capabilities with plans to roll out new features in FY27. In addition, the Company is implementing a driver on-boarding training to familiarize new employees with the vehicles they will be driving. This will have the greatest impact for employees driving larger vehicles and equipment.

UGI Gas is continuing to focus on High Energy Hazard Assessment and Energy Control in line with the Edison Electric Institute's Safety & Classification Learning Model, an industry-standard approach to categorizing safety learning opportunities to reduce potentially serious or fatal injuries. The UGI Gas Safety team is continuing to train employees in use of the model for hazard assessment for job planning in FY26 and FY27.

In FY26, UGI Gas plans to initiate an Occupational Health Program pilot aimed at reducing soft-tissue injuries. The pilot focuses on proactive injury prevention through onsite ergonomic assessments, individualized conditioning programs, and early-intervention strategies to address discomfort before it progresses to an injury. The program includes employee education on proper body mechanics, stretching and warm-up routines, and techniques to safety perform high-risk tasks such as lifting, bending, and repetitive motion. By integrating occupational health expertise directly into field operations, UGI Gas is working to reduce strain-related injuries, improve employee well-being, and enhance overall operational safety and productivity. The Company will review and evaluate the findings from the pilot in CY26 to determine how to proceed with further implementation in CY27.

Q. What other ongoing safety programs does the Company have?

A. Other ongoing safety measures and tools include Smith System driver training and a 24-hour Triage Nurse Hotline. The Company has also adopted multiple programs to enhance its safety protocols. One such program is the UGI "Making a Difference by Living Our Values" incentive program, which rewards employees who demonstrate positive safety behaviors, including, but not limited to, leading safety meetings, reporting safety issues, or

participating in safety education. UGI Gas has further implemented a "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. In addition, the Company uses EcoOnline, a safety incident software, which facilitates incident management and data collection for various types of incidents and tracks those incidents through the investigation process. Moreover, the Company utilizes ISNetworld vendor safety software to qualify contractors and monitor their performance trends. ISNetworld collects safety information from these contractors and compares them against UGI Gas's established safety standards to make sure their safety performance is at a satisfactory level to perform work for the Company. ISNetworld conducts ongoing monitoring of the contractor's safety information and alerts UGI Gas if a contractor falls below the Company's minimum safety standards – either in UGI Gas's service territory or anywhere else in the country. This helps ensure that UGI Gas's contractors provide safe and reliable service to the Company's community and customers.

Q. What training initiatives is the Company undertaking?

A. The Company has advanced its offerings at its Learning Center and continues to enhance the training program abilities there. The Learning Center is used for all new hire and employee progression field training. It is also used for ongoing training and operator re-qualification for employees and contractors. Key enhancements in Fiscal Years 2024-2025 were developing (1) training curriculum for meter and regulation field employees, incorporating Asset Data Collection ("ADC") training into existing course offerings; and (2) specialized training in medium and high pressure tapping.

The Company's OQ and technical training team has completed reorganizing, revising, and reformatting the training curriculum to enhance learning through incorporation of additional hands-on practice elements and interaction afforded at the Learning Center. The Company has aligned its operator qualification tasks with the American Society of Mechanical Engineers ("ASME") B31Q Standard. This transition to the B31Q standard aligns the Company with the latest industry best practices. This was completed in December 2025.

In FY25, UGI Gas implemented comprehensive Safety Leadership training for supervisors and above to strengthen UGI Gas' safety culture. The program focused on equipping leaders with the skills needed to model safe behaviors, conduct effective safety conversations, identify and mitigate hazards, and reinforce accountability across teams. In addition, UGI implemented human performance training to approximately 80% of its field workforce with the remaining 20% to be implemented in FY26. By enhancing leadership capability at all levels, these initiatives foster a work environment where employees feel empowered to speak up and prioritize safety in every task. As a result, UGI Gas expects long-term improvements in incident prevention, operational reliability, and overall employee engagement.

VII. ENVIRONMENTAL PROGRAMS

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on three main areas: (1) Manufactured Gas Plant ("MGP") remediation; (2) compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the mid-1800s through the mid-1900s, UGI Gas and its predecessors owned and operated a number of MGPs that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial, and industrial customer use. In Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this manufacturing process, including coal tars and other residues of the manufactured gas process, are today considered potentially hazardous substances under state and federal environmental laws. UGI Gas operates its environmental remediation program under a consent order and agreement ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP") that covers the Company's activities through October 1, 2035.[5] This COA obligates the Company to either meet an annual minimum environmental spend commitment of $5.35 million or achieve a minimum annual point total of 9,000 points,[6] with points being issued for the completion of various designated environmental tasks under the COA through October 1, 2035.

[5] Historically, UGI Gas operated its environmental remediation programs under three COAs with PADEP. UGI Gas's former utility companies, UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), were each parties to separate COAs with PADEP, and a UGI Gas COA was executed in 2016. Following UGI CPG and UGI PNG's merger into UGI Gas, on October 1, 2020, the three separate UGI COAs were consolidated into the single, current COA that runs through October 1, 2035.

[6] The COA includes an "accounting system" with provisions to track progress with respect to the investigation, characterization, and remediation of the MGP properties. In any given fiscal year, the Company is required to achieve a minimum of 9,000 points, which demonstrates efforts and progress toward remediation, or exceed the minimum required spend of $5.35 million.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs for site investigations, remediation, and site restoration as well as related PADEP oversight costs. Costs may also be incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and costs associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored. Costs may also be incurred to purchase a property to secure access to investigate and remediate. Additionally, expert and legal costs are sometimes incurred in interactions with insurance carriers or other potentially responsible parties to ensure that UGI Gas's customers are only paying their equitable share of investigation and remediation costs. These costs may also be incurred to implement PADEP workplans if the Company faces opposition to the investigation or remediation of the site. Costs may also be incurred to recover compensation under historical insurance policies to offset the costs that would otherwise be recovered from customers.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas has held the COA annual minimum spend of $5.35 million as the target projected spend for each year to meet the COA objectives, if minimum annual points cannot be achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is $6.698 million, as shown below in Table 2.

Table 2. Environmental Spent per Fiscal Year

Fiscal Year	Total
2023	$5,441,000
2024	$7,602,000
2025	$7,052,000
Average	$6,698,000

The three-year average amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Amy M. Keller (UGI Gas Statement. No. 5).

Q. Why does environmental spend vary from the minimum environmental spend set by the COA?

A. While the Company uses the COA minimum spend as a benchmark for environmental cost budgeting, actual costs may exceed the minimum in certain years due to PADEP requirements, varied levels of investigation and remediation activity to address MGP site program priorities, addressing public concerns, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. Investigation activities tend to involve lower costs than remediation activities, which have higher costs associated with the active removal or neutralization of impacted soil or groundwater.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the Company or the community. Because these MGP sites are located within the Company's existing service territory, restoration of the sites for beneficial reuse, whether in the form of use by the Company, urban redevelopment, or the creation of a new public space, directly benefits the customers and communities served by the Company.

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JEW-1

JILL WALTER

ALLENTOWN, PA | 267-249-7808 | jillwalter17@gmail.com

Utility Operations & Safety Leader | Business Process Improvement

Dynamic and results-driven utility operations leader with over 20 years of progressive experience driving performance, leading teams, and delivering strategic initiatives in high-pressure environments. Proven expertise in business process improvement, change management, and cross-functional collaboration. Recognized for a clear, effective communication style that connects across all organizational levels to build alignment and momentum. Adept at translating customer needs into actionable strategies and fostering strong trust-based relationships. A hands-on, influential leader with a strong blend of critical thinking, problem-solving, and operational excellence. ***Areas of expertise include:***

Safety & Quality Program Management ♦ Root Cause Analysis ♦ Operations Management ♦ KPI Management
Process Improvement & Automation ♦ Budget Management ♦ Forecasting ♦ Risk Management ♦ Cost Control
Customer Service ♦ Contract Management ♦ Policy & Procedure Development ♦ Effective Communication
Data Analytics & Reporting ♦ Executive Collaboration ♦ Team Leadership Business & Financial Analysis

***Technologies*: Microsoft Office Suite, SharePoint, Oracle, Work Management Software, Accounting Software**

CAREER SUCCESS

UGI Utilities, Bethlehem, PA — January 2023 – Present

Director Operations, South Region (January 2023 – present)

Direct and lead natural gas employees within the South Region (~400 employees) in safe, reliable and efficient natural gas installation, operation, and maintenance. Ensure fiscal responsibility for the South Region while driving efficiency in work processes. Provide leadership and promote communication and collaboration between departments across the company.

INTREN, Conshohocken, PA — October 2018 – January 2023

Regional Director, East (2018-2023)

Direct and lead gas and electric employees within in the East Region driving INTREN's core values and mission (~180 employees). Primary point of contact responsible for maintaining customer relationships and satisfaction within the region. Responsible for execution of contracts and the region's operating budget performance. Responsible for developing and implementing business development strategies within the region to promote growth. Drives a culture that embraces safety and quality and ensures safety and quality procedure adherence.

- Full P&L responsibility for ~$60m budget
- Improved gross margin by 12% in 2 years
- Led region through 300% growth in revenue over 4 years
- Improved OSHA recordable incidents within the region
- INTREN representative on NECA Northeast Lines Chapter

I.B. Abel, Inc., York, PA — January 2015 – September 2018

Director of Safety & Quality (2016-2018)

Directed and led employees within the Safety & Quality Department, including hiring, training and coaching. Managed the safety & quality management system by engaging customer, field and senior leadership. Increased quality, safety and efficiency by implementing process and IT improvement initiatives. IT focus areas include mobile computing, SharePoint and the tool & equipment request system. Managed all key performance metrics for the company including safety, project management, work management, financial, backlog, and resource planning.

- Improved OSHA recordable incidents by 30% through a proactive safety and human performance program.
- Developed company SharePoint site to provide office and field employees the ability to electronically submit timesheets, access customer specifications, request tools/equipment and submit company forms. Deployed tablets to approximately 100 field leadership employees.
- Developed and implemented the company's ISO 9001:2015 compliant Quality Management Program.
- Developed a corporate scorecard as well as department level scorecards to measure business performance.

JILL WALTER ALLENTOWN, PA | 267-249-7808 | jillwalter17@gmail.com

- Implemented a standard project management delivery process across all divisions improving project communications, reporting, efficiency, and profitability.
- Single point of contact for one of the largest investor owned utilities in the northeast US.

Manager – Project Management and Controls (2015-2016)

Spearheaded project management initiatives. Directed and led a team of six professional individuals that managed various size projects. Served as the Storm/Emergency Response Management Lead.

- Ensured safe and profitable execution of a $50M project portfolio for investor-owned utilities.
- Developed project controls, metrics, resource planning and backlog reporting within the Utility Services division.
- Implemented a standard process for responding to customers' resource requests during storms and emergencies. Improved company's response time by 25%.
- Single point of contact for one of the largest investor-owned utilities in the northeast US.

PPL Electric Utilities, Corp., Allentown, PA July 2002 - January 2015

Manager – Distribution Portfolio Management (2012-2015)

Managed a portfolio of $350M capital improvement projects, maintenance programs, and service work within the company's distribution and substation system.

- Improved the budget planning and monitoring process through improved proactive reporting and analysis.
- Developed and maintained an internal and external labor resource strategy for work related to distribution, transmission, metering, and substation work.
- Maintained all Work Management reporting and metrics to ensure adherence to current work management processes. Recommended and facilitated Work Management process improvement opportunities.
- Implemented the company's Distribution System Improvements Charge process (Act 11). Developed all required reporting and analysis for the PA Public Utility Commission (PUC) to support the rate structure as supporting general rate case filings.
- Provided direction and leadership to a team of six professional individuals that developed the annual work plan, work scope adherence, detailed budget variance analysis, monthly forecasting, unit rate analysis, and resource planning.

Program Manager – Advanced Metering Development (2010-2012)

Responsible for managing a $37 million project to pilot and test advanced metering technology. Piloted the ability of the company's metering system to integrate into multiple business processes and computer systems.

- Worked closely with the PA Public Utility Commission (PUC) to ensure the company was meeting all requirements of Act 129 including bi-annual stakeholder meetings and annual status update filings.
- Provided direction and leadership to a team of three professional individuals.

Key Account Manager (2008-2010)

Serve as single point of contact for 200 key business accounts in the Lehigh Valley.

- Collaborated with internal resources to ensure the needs of Key Accounts are met in an effective, efficient and timely manner.
- Developed a communication plan and strategy for transitioning business customers into new tariff rate structures after years of rate caps.
- Maintained a strong knowledge of electric issues, tariffs, rates and service requirements.

Functional Requirements Lead – Mobile Operations Management (2007-2008)

Responsible for identifying, documenting and testing functional business requirements for the Mobile Workforce Management application. Deployed approximately 350 laptops to the field workforce.

- On-time and successful implementation of the first phase of the project (software vendor selection, hardware selection, testing and deployment).

JILL WALTER
ALLENTOWN, PA | 267-249-7808 | jillwalter17@gmail.com

Support Engineer – Distribution Asset Management (2004-2007)

Analyzed the need for distribution system reinforcements and developed large capital projects to support the need. Performed system studies for the connection of customers and non-utility generators. Evaluated and recommended changes in methods, design, and equipment

- Streamlined the process for connecting non-utility generators to the company's distribution system.
- Developed improved method for tracking non-utility generators connected to the system.

Engineer – Asset Maintenance & Reliability (2002-2004)

Provided statistical and technical analysis to develop budget requirements for maintenance programs

- Developed and managed an Underground Cable Replacement Program.
- Created a process for responding to emergency fiber optic network issues.
- Published quarterly reliability reports to the Pennsylvania Public Utility Commission (PUC).

Cooperative Associate – Transmission Engineering (Summer 2001)

Supported Transmission Design Engineers with various projects. Prepared estimates on future transmission projects. Supported Siting Coordinator in writing PA PUC reports for new transmission lines.

EDUCATION AND CERTIFICATION

Master of Business Administration, Supply Chain Management Concentration, 2009
LEHIGH UNIVERSITY, Bethlehem, PA

Professional Engineer, 2008

Power Technology Certificate, 2005
SIEMENS, Schenectady, NY

Bachelor of Science in Electrical Engineering, Business Minor, 2002
VILLANOVA UNIVERSITY, Villanova, PA

COMMUNITY ENGAGEMENT

Trustee, Da Vinci Science Center, 2024 – Present

Volunteer/Committee Member, YWCA Perfect Fit, 2024 – Present

Campaign Champion, United Way Lehigh Valley, 2024 - Present

Volunteer, Meals on Wheels Driver, 2021 - present

UGI GAS STATEMENT NO. 4

VIVIAN K. RESSLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 4

Direct Testimony of
Vivian K. Ressler

Topics Addressed: **Budgeting Process**
Operating Expense Adjustments
Capital Treatment of Certain Information Technology Costs

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Director – Utility Financial Planning & Analysis ("FP&A"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Director – Utility FP&A?

A. I have responsibility for UGI's financial budgeting, forecasting and analysis processes. I lead a team of analysts responsible for preparing the annual budget, including obtaining input from operational departments throughout the business. The team also performs analysis of budget to actual variances and completes financial forecasting and modeling to support business decisions. My duties also include the coordination of these functions with UGI's Accounting Department and the UGI Corp. Sr. Director of FP&A as well as finance and accounting personnel at UGI Corp.

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Gas Exhibit VKR-1.

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit VKR-1 provides a list of the proceedings in which I have testified.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case budgeting methodology and certain operating expense adjustments. First, I will discuss the budgeting process used by UGI Gas (Section II). Next, I will discuss certain operating expense adjustments (Section III). Finally, I will discuss the Company's accounting for certain Information Technology ("IT") costs (Section IV).

Q. Ms. Ressler, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibit VKR-1. In addition, I am sponsoring those portions of UGI Gas Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address certain adjustments to operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

II. BUDGETING PROCESS

Q. Please provide a high-level summary of UGI Gas's budgetary preparation and approval process.

A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Gas Operating Budget for the subsequent two fiscal years begins during the spring, *i.e.*, the budget process for the October 1, 2025 through September 30, 2026 fiscal year (Fiscal 2026) and the October 1, 2026 through September 30, 2027 fiscal

year (Fiscal 2027) begins in the spring of 2025, with information being requested and incorporated from all departments. This allows UGI Gas to utilize the budget as a starting point for its FPFTY rate claim. Internal reviews and revisions occur throughout the spring and summer before the final budget for UGI Corp. is approved by the UGI Corp. Board of Directors in September – immediately prior to implementing the budget. I provide further detail regarding the preparation of the "Operating" and "Capital" Budgets below.

Q. Please describe how the Operating Budget is prepared.

A. As an initial matter, I note that the Operating Budget has both a revenue and expense component, which I will discuss in turn. In addition, each element of the UGI Gas Operating Budget is formulated by personnel with responsibilities specific to each aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

The revenue portion of the budget is a joint effort between the Marketing and FP&A departments. The Marketing department provides customer growth and attrition information by customer class along with specific large commercial and industrial sales, and revenue budget projections. The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, and shifts in type of residence and customer mix. Budgeted usage per customer is developed by application of a two-year regression to historic data and incorporates normal weather on a 10-year basis (with such normal weather period being as defined by UGI Corp. for use in the budget process). The budgeted number of customers and usage per customer are combined to

produce monthly budgeted sales. The revenue budget is calculated by applying appropriate rates for each customer class to budgeted sales volumes, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management. Normalizing and annualizing ratemaking adjustments to the budget for presentation of the FPFTY sales and revenue in this filing are discussed in the direct testimony of UGI Gas witness Sherry A. Epler (UGI Gas Statement No. 10).

Concurrent to revenue development, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by functional managers based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and staffing levels are set for the upcoming fiscal years. The direct expense portion of the Operating Budget is submitted for review and approval by senior management. UGI Gas's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Gas to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, commodity supply, human resources, information systems, payroll, customer relations, billing, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements.

The final Operating Budget is then submitted to UGI's President for review and approval. After this approval, the UGI budget is submitted to the Chief Financial Officer at UGI Corp. for additional review and approval and is consolidated with the budgets of other operating units of UGI Corp. The President of each UGI Corp. business unit reviews

his or her budget with the UGI Corp. Board of Directors and then the UGI Corp. Board of Directors approves the consolidated UGI Corp budget.

Q. Please describe how the Capital Budget is prepared.

A. In order to prepare the Capital Budget, operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described, and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priority, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. This Capital Budget is subject to approval by the UGI Corp. Board of Directors in a manner similar to that described above for the Operating Budget. Additional information concerning the factors considered in establishing the UGI Gas Capital Budget is provided in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 7).

Q. Please explain how expenses from affiliated companies are treated to develop the budgeted Statement of Operations.

A. UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns applicable costs between UGI Electric and UGI Gas. Costs that can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs that cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service.

Allocations are made by using a methodology applicable to the cost (*e.g.*, budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by using a formula referred to as the Modified Wisconsin Formula ("MWF") or another reasonable allocation methodology. The MWF or other allocation methodology achieves a reasonable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units which benefit from the respective activities. Activity is measured by revenues and operating and maintenance ("O&M") expenses. Size is measured by tangible net assets employed (excluding acquisition goodwill) or by gross plant balance.

Q. How is the budget information used to support UGI Gas's requested revenue increase?

A. This budget information is the starting point for UGI Gas's claims and is adjusted as appropriate to reflect certain anticipated changes based on ongoing business activities since the completion of the budgeting process and through application of other appropriate ratemaking principles.

III. OPERATING EXPENSE ADJUSTMENTS

Q. Please describe how the Company's claimed operating expenses were determined.

A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting point. This budgeted level of expenses was then adjusted to comply with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. The supporting schedules for those adjustments are found in UGI Gas

Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating adjustments that I am sponsoring, as contained in UGI Gas Exhibit A (Fully Projected), Section D.

1. Uncollectible Accounts Expense

Q. Please explain the adjustment shown on Schedule D-11 for Uncollectible Accounts Expense.

A. This adjustment, ($0.330) million (line 8, column 5), adjusts budgeted uncollectible accounts expense to reflect a three-year average rate of uncollectible accounts expense to tariff revenue for Fiscal Years 2023, 2024, and 2025.

The amount of uncollectible expense in the budget is adjusted utilizing the three-year average uncollectible rate of 1.723 percent (line 4, column 5). The 1.723 percent is applied to the *pro forma* revenues at present rates (line 6, column 3) to calculate the *pro forma* uncollectible accounts expense of $21.139 million (line 7, column 4). This results in a decrease in the level of uncollectible accounts expense for the FPFTY from the budgeted amount of $21.469 million (line 5). The 1.723 percent uncollectible rate is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

2. Injuries and Damages Adjustment

Q. Please discuss the adjustment for Injuries and Damages shown on Schedule D-15.

A. The amount of expense incurred for injuries and damages in any one year can vary based on the quantity and severity of the claims. The Company bases its claim for injuries and

damages on a normalized amount. This is accomplished by making an adjustment on this schedule for the difference between the normalized amount and the budgeted amount. The three-year average of injuries and damages expenses of $1.863 million is calculated on lines 1 – 4 of Schedule D-15. The budgeted amount for injuries and damages, $0.987 million, is shown on line 5. The difference between these amounts, $0.876 million, was used to adjust budgeted injuries and damages expense, as shown on line 6, to reflect the normalized expense.

3. Customer Accounts Expense Adjustment

Q. Please discuss the adjustment for Customer Accounts Expense shown on Schedule D-15.

A. This adjustment includes a component to recover interest on customer deposits. The Company is required to pay interest on customer deposits that it holds in accordance with its tariff requirements. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the Operations Budget. It is calculated by using the average level of customer deposits anticipated for the FPFTY (*i.e.*, $23.197 million) times the required interest rate (7.0 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and as required under the Company's tariff. The total interest on customer deposits, an amount of $1.624 million, is shown on line 7.

4. PUC Assessment

Q. Please discuss the adjustment for PUC assessment shown on Schedule D-15.

A. This adjustment reflects the difference between the budgeted PUC assessment expense ($5.131 million on line 9) and the projected annual PUC assessment expense as of September 30, 2027 ($6.006 million on line 8). This adjustment of $0.875 million (line 10) is necessary to (1) adjust from the budget timing (October through September) to the timing of the PUC assessment (July through June); and (2) update the projection amount based on the most recent PUC assessment invoice (which was received subsequent to completion of the Company's budget).

IV. CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS

Q. What is the Company's policy for capital treatment of IT costs?

A. Since 2016, UGI (including UGI Gas and UGI Electric) has received authorization to capitalize certain IT costs associated with software implementation projects within various base rate proceedings. These IT costs consist of internal labor, external consulting expenses, and other expenses related to the preparation of the vendor and system integrator requests for proposals. IT costs also include current-state assessments, reengineering business processes to adapt to the new system, data conversion, cleansing and migration (including field verification and digitization of asset attributes required for accurate data and facility capture), and implementation training costs. Additionally, the Company capitalizes the above-mentioned cost items for cloud computing software implementation projects. Further, beginning in 2019, the Company began capitalizing Hypercare costs associated with large software implementation projects. Hypercare is a term for post-

implementation support following the deployment of an IT project to ensure that the newly implemented system operates as planned.

Q. Is the Company planning to continue with similar methods of IT cost capitalization in this proceeding?

A. Yes. The Company continues to capitalize such costs in line with the authorizations received previously, and all such costs which are claimed in the current case are included within the Company's budgeted capital as laid out in Exhibit A (Future) and Exhibit A (Fully Projected).

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VKR-1

Vivian K. Ressler

Director – Utility Financial Planning & Analysis

Work Experience

UGI Utilities, Inc. – Denver, PA

Oct. 2024 – Current	Director – Utility Financial Planning & Analysis
Jan. 2023 – Sept. 2024	Sr. Manager - Finance
March 2022 – Jan. 2023	Assistant Controller
Dec. 2021 – March 2022	Sr. Manager – Plant & Regulatory Accounting
Feb. 2020 – Dec. 2021	Sr. Manager – SOX, Plant Accounting & Accounts Payable
June 2018 – Feb. 2020	Manager – Technical Accounting & Controls

The Bon-Ton Stores, Inc. – York, PA

May 2014 – May 2018	Departmental Vice President – Corporate Accounting

Trout, Ebersole & Groff, LLP – Lancaster, PA

May 2012 – May 2014	Supervisor – Attest Services

BI-LO, LLC – Greenville, SC

Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax

Deloitte & Touche, LLP – Greenville, SC

Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services

Previous Testimony before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Electric Base Rate Case	Docket No. R-2021-3023618
UGI Gas Base Rate Case	Docket No. R-2021-3030218
UGI Electric Base Rate Case	Docket No. R-2022-3037368
UGI Gas Base Rate Case	Docket No. R-2024-3052716

Education & Professional Certification

B. S. in Accounting – Bob Jones University, Greenville, SC

Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS STATEMENT NO. 5

AMY M. KELLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 5

Direct Testimony of
Amy M. Keller

Topics Addressed:	**Accounting Process and Historic Costs**
	Fully Projected Future Test Year
	Rate Base
	Operating Expense Adjustments

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Amy M. Keller. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager, Regulatory and Plant Accounting. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Manager, Regulatory and Plant Accounting?

A. I have responsibility for UGI's plant accounting and regulatory accounting processes. I lead a team of accountants responsible for maintaining complete and accurate plant accounting records, and for preparing and submitting certain regulatory filings with the PUC and Federal Energy Regulatory Commission ("FERC"). My duties also include the coordination of these functions with UGI's Assistant Controller as well as financial accounting and reporting personnel and UGI Corp.

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Gas Exhibit AMK-1.

Q. Have you testified previously before this Commission?

A. No, I have not.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case accounting methodology and certain operating expense adjustments. First, I will explain UGI Gas's accounting processes, which were used to develop the actual book accounting results, which are the basis for the Company's historic test year ended September 30, 2025 ("HTY") (Section I).[1]

Q. Ms. Keller, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibits AMK-1 and AMK-2. In addition, I am sponsoring those portions of UGI Gas Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Gas maintained?

A. The accounting records of UGI Gas are kept in accordance with generally accepted accounting principles ("GAAP") and the Federal Energy Regulatory Commission's

[1] The budgets for the future test year ending September 30, 2026 ("FTY") and the FPFTY are discussed in the Direct Testimony of Tracy A. Hazenstab (UGI Gas St. No. 2).

("FERC") Uniform System of Accounts ("USOA") as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.46.

Q. Are the books and records of UGI Gas subject to audit?

A. Yes. The books and records of UGI Gas are audited by its internal auditors. In addition, UGI Gas's books and records are included in Company-wide audits of UGI, performed by its external auditor, KPMG, LLP. The Company's books and records are further subject to audit by the PUC.

Q. Do the continuing property records of UGI Gas reflect the original cost value of property?

A. Yes, they do. UGI Gas's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the USOA requirements.

Q. What process does UGI Gas follow to assure that property reflected in its plant accounts is in service?

A. UGI Gas's capital project managers create records that document the costs of projects and/or asset purchases. When a capital project or asset is placed into service, the project manager records the in-service date and the retirement detail for any related assets that are taken out of service. Then, the record is provided to accounting personnel. This information is transferred through accounting entries into the appropriate UGI Gas plant

property accounts, subject to review by authorized individuals who approve the entries and further review by internal and external auditors.

Q How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits that support UGI Gas's claim in this proceeding. As discussed in the direct testimony of Company witnesses Hans G. Bell (UGI Gas Statement No. 1) and Tracy A. Hazenstab (UGI Gas Statement No. 2), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Gas's Operating and Capital Budgets for the 12 months ending September 30, 2027, as shown in UGI Gas Exhibit A (Fully Projected). The accounting data for the FTY was derived from UGI Gas's Operating and Capital Budgets for the 12 months ending September 30, 2026, as shown in UGI Gas Exhibit A (Future). The accounting data for the HTY was derived from UGI Gas's books and records for the 12 months ended September 30, 2025, as shown in UGI Gas Exhibit A (Historic).

III. FULLY PROJECTED FUTURE TEST YEAR RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. It summarizes the UGI Gas rate base values for the FPFTY. Column 1 provides the schedule where the calculations of each of the rate base elements are found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim—net of deductions for accumulated depreciation,

accumulated deferred income taxes and customer deposits—is $4.319 billion. Except where otherwise noted, I will describe each of the rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Gas determined its FPFTY rate base value for net plant in service.

A. UGI Gas's claim for FPFTY rate base value for net plant in service is the sum of the gross utility plant in service claim and the accumulated depreciation claim as of September 30, 2027, as described below.

Gross utility plant in service represents the sum of the closing plant balances as of September 30, 2025, plus budgeted additions placed in service for the years ending September 30, 2026, and September 30, 2027, less expected FTY and FPFTY plant retirements. The direct testimony of Company witness Vicky A Schappell (UGI Gas Statement No. 7) discusses the capital addition planning process and the basis for the additions placed in service in the FTY and FPFTY.

UGI Gas's claim also reflects a reduction for accumulated depreciation, which is based on the closing accumulated depreciation balances as of September 30, 2025, plus depreciation expenses for the years ending September 30, 2026, and September 30, 2027, less expected FTY and FPFTY plant retirements.

Q. Please describe Schedule C-2 to UGI Gas Exhibit A (Fully Projected).

A. This schedule presents UGI Gas's FPFTY claim of $6.677 billion for used and useful gas gross utility plant in service on page 2, column 2, line 64. That amount is also reflected on

line 1 of the measure of value summary on Schedule C-1. Gas utility plant enables UGI Gas to provide safe and reliable gas service to its customers.

Q. Please describe the information included on Schedule C-2, page 3.

A. This information provides a summary of UGI Gas's *pro forma* claim for gross utility plant in service by category. Column 2 shows the FPFTY ending balances based on the placed in-service budget; column 3 shows the net effect of the various plant adjustments, if any; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, pages 4 and 5?

A. Columns 2 and 3 on these pages show the gas plant in service balances for 2026 and 2027 at the FERC account level, based on the placed in service budget. Column 5 provides the ending FPFTY plant balance at the FERC account level.

Q. Where are plant in service additions shown?

A. Pages 6 and 7 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant in service additions. The Company categorizes plant in service additions by FERC account.

Q. Where are plant retirements shown and how were these retirements projected for the FTY and the FPFTY?

A. Pages 8 and 9 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant retirements. Retirements for most plant accounts were projected by

plant account. The Company applied the average retirement rate, as a percent of additions, for the five fiscal years 2021 through 2025, to the FPFTY and FTY plant in service additions. For certain plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Gas determined its rate base deduction for accumulated depreciation.

A. UGI Gas started with accumulated depreciation as of September 30, 2025, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Weidmayer (UGI Gas Statement No. 6), with the underlying FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

Q. Please describe UGI Gas's accumulated depreciation claim.

A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit A (Fully Projected). This schedule presents the accumulated provision for depreciation as of September 30, 2027, distributed among the various FERC accounts. The total amount for accumulated depreciation, $1.736 billion, is summarized on page 2, column 2, line 64, of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1 as a reduction to rate base.

Page 3 of Schedule C-3 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Pages 4 and 5 show the details of the accumulated depreciation by FERC account for Fiscal Years 2026 (column 2) and 2027 (column 3) based on budget plus adjustments (column 4), if any, to arrive at the FPFTY balance (column 5). Pages 6 and 7 show the cost of removal by FERC account and pages 8 and 9 show negative net salvage amortization by FERC account. Pages 10 and 11 include the salvage amounts by FERC account. These amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

Q. Please summarize UGI Gas's net in plant in service claim.

A. UGI Gas's net plant in service claim reflects *pro forma* gross utility plant as described above of $6.677 billion at September 30, 2027, less *pro forma* accumulated depreciation of $1.736 billion at September 30, 2027. These amounts are both reflected in the measure of value summary on Schedule C-1.

3. Cash Working Capital

Q. Please explain how UGI Gas determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Gas's CWC requirements is provided in Schedule C-4.

Q. Where is the CWC rate base value summarized?

A. The CWC rate base value is summarized at Schedule C-4, page 1. The various components of the working capital claim are listed on this page, along with a reference to the page where the component is further detailed within Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense payment lag. The revenue lag is 57.46 days (line 1). Expense lag days include three categories of annual operating expenses: (1) payroll; (2) purchased gas costs; and (3) other expenses. The expense lag days are shown for each component (lines 3-5), which amount to 27.55 days (line 7). The net lag in the collection of revenue is 29.91 days (line 8). This number is then multiplied by the average daily operating expense balance (line 9) to arrive at a base CWC amount for Operations and Maintenance ("O&M") expense of $57.012 million (line 10). The average daily expense balance of $1.906 million (line 9) is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense, of $695.601 million (line 6, column 2), by the number of days in the year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The Company's calculation for the total revenue lag days of 57.46 (line 23) consists of several steps. First, the annual revenue (line 18, column 3) is divided by the average month-end accounts receivable balances for the 13 months ended September 30, 2025 (line

17, column 2). This results in an accounts receivable turnover rate of 9.14 (line 19, column 4), which is equivalent to 39.93 lag days (line 20, column 5) (i.e., 365 divided by 9.14 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to: (1) the 2.32-day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company (appearing on line 21); and (2) the 15.21-day service lag (i.e., midpoint lag factor), which is the time from the mid-point of the service period until the meter reading date (appearing on line 22). This calculation results in a total revenue lag of 57.46 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.4 days) divided by two (i.e., 15.21 days).

Q. How are the payroll expense lag days for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the pay period divided by 2 (for an average), with a 5-day payroll processing time period added, resulting in a 12-day lag period.

Q. How were the lag days associated with the purchased gas costs shown on Schedule C-4, page 4, line 8, calculated?

A. This calculation is shown on page 6 of Schedule C-4 and is based on a review of gas purchases during the 12-month period of October 2024 through September 2025. The total dollar amount of gas purchased during this period was $505.975 million (on line 13, column 2). The average payment lag was calculated by dividing the total dollar days for purchased gas costs ($13.199 billion) by the total dollar amount of gas purchased ($505.975 million), which equals 26.09 days (on line 14). The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period. The 26.09-day lag for purchased gas costs is then brought forward to Schedule C-4, page 4, line 8, and Schedule C-4, page 2, column 3, line 4.

Q. What are dollar days, and how were they used in the CWC calculation?

A. Dollar days are the product of a payment amount multiplied by the number of days between the invoice date or service date and the date that the payment clears the Company's bank. The dollar days calculation is used to calculate a weighted average number of lag days for both purchased gas costs (Schedule C-4, page 6) and general disbursements (Schedule C-4, page 5).

Q. How were the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 22, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over the HTY, as shown in more detail on page 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date, the amount of the disbursement, the date the payment was made, and the type of disbursement (for capital, commodity, or expense), during each of these months was used. As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days for expense purchases were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire and Automated Clearing House ("ACH") payments, or (ii) the number of days from the invoice date until check date, plus seven days (representing mail lag) for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, gas purchases) or were paid for capital items. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25, resulted in a payment lag for general disbursements of 36.55 days. The lag for other disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1, was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $0.280 million shown on page 7, line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $9.459 million as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the tax payment lag for the working capital requirement, shown on line 3 of Schedule C-4, page 1, determined?

A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations (for working capital) are made for federal income tax, state income tax, PA Property Tax, and the Public Utility Realty Tax Act ("PURTA"). Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The results for each of these components are shown and summed in column 10 to derive the net working capital allowance for tax payments of $4.570 million shown on page 8, line 19. This amount is then included on page 1, line 3 of Schedule C-4.

Q. How was the working capital allowance for prepaid expenses, shown on line 4 of Schedule C-4, page 1, derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the 13-month average of actual pre-paid amounts for each month ended from September 2024 through September 2025. The 13-month average of total actual pre-paid amounts during that period is $14.400 million, shown on page 9, line 18. This amount is then included on page 1, line 4 of Schedule C-4.

Q. What is the total amount of the Company's CWC claim?

A. UGI Gas's claim for CWC is $66.523 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Gas Storage Inventory

Q. Please explain how the rate base value for gas storage inventory was determined.

A. Gas storage inventory represents gas volumes stored in facilities or in storage fields owned by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As is typical for most natural gas distribution systems, UGI Gas purchases storage gas throughout the year for use primarily during the winter heating season. Specifically, the Company pays its gas storage bills on a monthly basis once the gas is procured in the same way that it pays for gas procured from other sources. Storage inventory is a physical asset that is included in the Company's rate base claim in the same manner as materials and supplies inventory. UGI Gas's claim for gas storage inventory is based on a 13-month average book value for the period ending September 2025, as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $23.662 million, as shown on

Schedule C-5, line 16. This amount is also used in Schedule C-1, line 5 and Schedule A-1, line 5.

5. Accumulated Deferred Income Taxes

Q. Please explain how the rate base value for Accumulated Deferred Income Taxes ("ADIT"), including Excess Deferred Federal Income Taxes ("EDFIT"), was calculated.

A. The Company's determination of its rate base value for ADIT, including EDFIT, is shown on Schedule C-6 and is discussed in the direct testimony of Darin T. Espigh (UGI Gas Statement No. 9). This amount of $716.793 million reduces the rate base. This amount is also used in Schedule C-1, line 6 and Schedule A-1, line 6.

6. Customer Deposits

Q. Please explain how the Company calculated the rate base value for customer deposits.

A. Customer deposits offset the need for UGI Gas to provide capital. UGI Gas's claimed offset for customer deposits is based on the average customer deposit balance for the 13-month period ending September 2025, as shown on Schedule C-7.

Q. What is the amount of the rate base offset for customer deposits?

A. The customer deposit offset is $23.197 million, as shown on Schedule C-7, line 16, Schedule C-1, line 7, and on Schedule A-1, line 7.

7. Materials and Supplies Inventory

Q. What is the rate base claim for materials and supplies inventory?

A. UGI Gas maintains various materials and supplies in inventory for use in its operations. The Company's claim for materials and supplies inventory is $28.644 million, as shown on Schedule C-8, line 16, Schedule C-1, line 8, and on Schedule A-1, line 8. This amount is based on the average inventory for the 13-month period ending September 30, 2025, as shown on Schedule C-8.

IV. OPERATING EXPENSE ADJUSTMENTS

Q. Please describe how the Company's claimed operating expenses were determined.

A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting point. This budgeted level of expenses was then adjusted to comply with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. The supporting schedules for those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating adjustments that I am sponsoring, as contained in UGI Gas Exhibit A (Fully Projected), Section D.

1. Environmental Remediation Expenses

Q. What adjustments are shown on Schedule D-8?

A. Consistent with the methodology the Company has used in past rate cases, the two adjustments shown on Schedule D-8 are designed to reconcile past Environmental Remediation expense rate recoveries with actual incurred costs and to recover a projected

annual level of Environmental Remediation expense. These costs are incurred in connection with UGI Gas's obligations under a Consent Order Agreement ("COA") with the Pennsylvania Department of Environmental Protection ("DEP").[2] The Company's remediation activities under the COA are discussed in the direct testimony of Jill E. Walter (UGI Gas Statement No. 3).

Q. Please describe the first Environmental Remediation expense adjustment shown on Schedule D-8.

A. The adjustment (on lines 1 – 6 of Schedule D-8) is intended to provide the Company with normalized ratemaking recovery of ongoing annual cash expenditures primarily to remediate former manufactured gas plant ("MGP") sites in accordance with the COA. Because the amount budgeted is the amount UGI Gas recovered in the most recent previous base rate case, it does not properly reflect the amount that the Company is likely to incur during the FPFTY. Therefore, as in past cases, the Company has chosen to normalize the expenditure based on its recent actual experience.

The average of the last three years of cash expenditures for remediation expenses under the COA is $6.698 million and represents the amount that the Company anticipates it will spend in the FPFTY under the COA. The difference between this annual amount ($6.698 million) and the amount budgeted by the Company ($5.429 million), or $1.269 million, is the first adjustment.

[2] Effective October 1, 2020, DEP consolidated the Company's prior three COAs (which aligned with the Company's former rate districts) into one COA that covers the entire UGI Gas service territory.

Q. Please describe the second Environmental Remediation expense adjustment shown on Schedules D-8, lines 7-13.

A. The second environmental adjustment (on lines 7-13 on Schedule D-8) shows the net under-recovery of the Company's MGP remediation expense incurred in past years, and the planned amortization for this net under-recovery. This net under-recovery resulted from the combination of (1) the under-recovery in actual annual remediation costs for Fiscal 2025 versus the normalized level authorized in the 2025 Gas Rate Case at Docket No. R-2024-3052716 and (2) over-recovery of reconciliation amounts from years prior to Fiscal 2025 (projected through Fiscal 2026). Please use the detailed calculations of this net over-recovery at UGI Exhibit AMK-2.

The under-recovered expenditures of $0.967 million (line 9) will be charged to customers over a two-year amortization period through Fiscal Year 2028, at an amount of $0.483 million per year (line 11). This two-year amortization period is consistent with the period approved in the settlement of the prior rate case at Docket No. R-2024-3052716. This amount is compared to the budget amount of $0.610 million of income per year, resulting in a budget adjustment of $1.093 million (line 13).

Q. Please describe the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 reflects an adjustment from budgeted pension expenses to reflect cash to be contributed to the plan in the FPFTY. The Company's budget reflects pension expenses based on GAAP requirements to reflect service and non-service costs based on certain assumptions. However, consistent with prior ratemaking practices, the Company claims pension costs within its rates on a cash basis. The adjustment is

calculated as the total cash contributions (as provided by the Company's actuary in the most recent actuarial report), reduced to reflect only the portion attributable to UGI Gas, and then further reduced to reflect the portion of pensions that is capitalizable. This cash pension expense of $4.507 million (line 5) is compared to the budgeted pension expense of $1.437 million (line 1), also calculated for UGI Gas only and net of the capitalizable portion, resulting in an adjustment of $3.071 million (line 6).

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT AMK-1

Amy M. Keller

Senior Manager – Regulatory and Plant Accounting

Work Experience

UGI Utilities, Inc. – Denver, PA

Oct. 2025 – Current	Senior Manager – Regulatory and Plant Accounting
Dec. 2021 – Sep. 2024	Manager of Process Improvement
Feb. 2020 – Nov. 2021	Manager of General Ledger and Regulatory Accounting
Feb. 2018 – Jan. 2020	Manager of Revenue and Supply Accounting
May 2016 – Jan. 2018	Supervisor of Revenue Accounting

Penn National Gaming. – Wyomissing, PA

May 2015 – May 2016	Senior Auditor, Internal Audit

Fulton Financial Corporation – Lancaster, PA

Jan. 2013 – May 2015	Senior Auditor, Internal Audit

Baker Tilly (formerly ParenteBeard, LLC) – Wyomissing, PA

Jan. 2010 – Jan. 2013	Intern through Staff Accountant II, Small Business Division

Education & Professional Certification

B. S. in Accounting – Albright College, Reading, PA
B. S. in Psychology – Elizabethtown College, Elizabethtown, PA

Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS

EXHIBIT AMK-2

UGI Utilities, Inc. - Gas Division
Reconciliation of Environmental Recovery Reconciliation by Fiscal Year
$ Amounts in '000s

Under / (Over) Recoveries Approved in Prior Rate Case:

Year(s) to which Under / (Over) Recovery Relates	Docket No. of Rate Case in which Amortization was Mostly Recently Approved	Per month Amortization as approved in docket # R-2021-3030218	Per month Amortization as approved in docket # R-2024-3052716	Under Recovered Balance at 9/30/2025	Amount in Rates by Fiscal Year FY26 (1)	Under / (Over) Recovered Balance at 9/30/2026	
FY24 and prior	R-2024-3052716	(252)	51	(1,221)	307	(914)	
Total		(252)	51	(1,221)	307	(914)	**Schedule D-8 Line 7**
					(1)	**(2)**	

Under / (Over) Recoveries since Prior Rate Case:

Year(s) to which Under / (Over) Recovery Relates	Spend per fiscal year	Amortized in Rates allowed by rate case	Under / (Over) Recovery	Under / (Over) Recovered Balance at 9/30/2026	
FY25	7,052	(5,171)	1,880	1,880	
Total	7,052	(5,171)	1,880	1,880	**Schedule D-8 Line 8**
				(2)	

(1) Amount includes one month of prior rate case amortization (rates approved at Docket #R-2021-3030218) and eleven months of the rates approved in the new rates (rates approved at Docket #2024-3052716, effective October 28, 2025).
(2) Amounts are included within Environmental Adjustment #2 at Schedule D-8 of Exhibit A, Fully Projected.

UGI GAS STATEMENT NO. 6

JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of John F. Wiedmayer, C.D.P.

Topics Addressed: **Depreciation and Net Salvage**

Date: January 28, 2026

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2025-3059523

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB degree in Engineering from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I

served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 35 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including the Pennsylvania Public Utility Commission ("PUC" or "Commission").

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to Project Manager, Depreciation Studies and in January 2022 I was promoted to my present position as Senior Project Manager, Valuation and Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended

depreciation rates to management for its consideration, and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming, I have assisted in the preparation of numerous depreciation studies for utility companies across various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone Company, Telus, United Telephone Company of New Jersey, and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, BGE, UGI Utilities, Inc. - Electric Division ("UGI Electric"), Penelec, Metropolitan Edison, ConEdison, ComEd, Orange and Rockland, Rockland Electric, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc. – Gas Division, North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, Connecticut Natural Gas, Southern Connecticut Gas, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the New York Public Service Commission, the Connecticut Public Utilities Regulatory Authority, and the PUC.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." In 2000, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve Imbalances and True-Up," and "Data Requirements for a Depreciation Study."

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the Pennsylvania gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I was retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2027, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Gas's depreciated original cost of gas plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual

depreciation expense to be included in the ratemaking cost of service as of September 30, 2027.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI Gas Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
I-A-8	Trended Original Cost Methodology
I-A-9	Spot Trended Original Cost
I-A-10	Undepreciated Original Cost
I-A-11	Cumulative Trended Depreciated Original Cost
l-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI Gas?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI Penn Natural Gas (“PNG”) base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two UGI Central Penn Gas

("CPG") base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the five most recent base rate case for UGI Utilities, Inc. – Gas Division at Docket No. R-2015-2518438, Docket No. R-2018-3006814, Docket No. R-2019-3015162, Docket No. R-2021-3030218 and Docket No. R-2024-3052716. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's base rate case filed in 1995 at Docket No. R-00953297.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ("FPFTY") ending September 30, 2027, for UGI Gas. UGI Gas Exhibit C (Future) presents similar summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ("FTY") ending September 30, 2026. UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ("HTY") ended September 30, 2025. Each of the three exhibits is organized in a similar manner and contains information and schedules supporting the amounts applicable to each test year period. UGI Gas Exhibit C

(Future) contains additional information including the supporting life tables and life table charts related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2027?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study reports, UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected).

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report prepared by me and submitted in 2023 based on plant accounting data through September 30, 2022. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis, including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group procedures used for calculating annual and accrued depreciation; and (2) an explanation of the

manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2026. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2026. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the years 2022 through 2026.

UGI Gas Exhibit C (Fully Projected) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2027. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected) inasmuch as the estimates are the same for all three test years, i.e., HTY, FTY, and FPFTY. The service life estimates set forth in UGI Gas Exhibit C (Historic) are the same estimates as those approved in the Company's Annual Depreciation Report ("ADR") submitted to the PUC in March 2025. The pro forma depreciation expense for UGI Gas at the end of the HTY,

September 30, 2025, is the sum of the three former rate districts, UGI South, UGI North, and UGI Central.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-3 through II-5 of UGI Gas Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve as of September 30, 2027, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-6 through II-7 of UGI Gas Exhibit C (Fully Projected), presents the bring-forward to September 30, 2027, of the depreciation reserve as of September 30, 2026. Table 3, pages II-8 through II-9 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-10 through II-11 of UGI Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2023 through 2027. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2022 through September 30, 2027. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2027, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2026.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Gas Exhibit C (Historic) is organized similarly to UGI Gas Exhibit C (Fully Projected). UGI Gas Exhibit C (Historic) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations;

and the detailed depreciation calculations as of September 30, 2025. The service life estimates used in the HTY period were based on the survivor curve estimates set forth in the ADR submitted to the PUC in March 2025. The same survivor curve estimates were used in each of the three respective test year periods and were based on a service life study submitted to the PUC in 2023 using plant accounting data through fiscal year-end 2022. The summary tables and detailed depreciation calculations as of September 30, 2025, are organized and presented in the same manner as those as of September 30, 2027, with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation."

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities, and the exhaustion of natural resources.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner. For clarity of presentation, the detailed depreciation calculations are presented by account, vintage year and former rate district, the sum of which totals to the consolidated PA-jurisdictional UGI Gas company which excludes a small portion of the UGI gas system located in Maryland. The depreciation summary tables present the results on a total PA-jurisdictional UGI Gas basis.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation that were used in the Company's March 2025 ADR?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for over forty years. The depreciation methods and procedures are described further in Part II of UGI Gas Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397, and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of gas plant to be included in rate base in this proceeding?

A. As of September 30, 2027, the original cost of gas plant in service is $6,676,559,249 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Gas Exhibit C (Fully Projected). This amount includes $6,381,927,213 of Gas Plant and $294,632,036 of Other Utility Plant allocated to UGI Gas. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used between UGI Gas and UGI Electric. The costs related to Common Plant and IS are allocated to UGI Gas at 89.11 percent and 84.82 percent, respectively. Also, the full cost of the buildings at the Empire Service Center ("Empire") in Wilkes Barre, PA were included in Gas Division. However, personnel of UGI Electric share portions of the buildings at that location and therefore a portion of the cost related to Empire was deducted from UGI Gas and allocated to UGI Electric for this proceeding.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2027?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2027, to be $1,736,045,978.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over forty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve set forth in the Company's financial statements and approved annually in connection with the Company's submission of its annual depreciation report each March to the Commission.

Q. How did you determine UGI Gas's allocated book depreciation reserve as of September 30, 2026?

A. The book depreciation reserve attributable to UGI Gas as of September 30, 2026, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book depreciation reserve as of September 30, 2025, using estimated accruals, retirements, salvage, and cost of removal for the twelve months from October 2025 through September 2026. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2025, the estimated reserve activity, and the ending reserve balance as of September 30, 2026. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6), and projected cost of removal (column 7). Table 3 of UGI Gas Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2025, by plant account, shown

in column 2 of Table 2, was obtained from UGI Gas's books and records and are the same amounts set forth in Table 1 of Exhibit C (Historic).

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2026.

A. The depreciation accruals for the twelve months ended September 30, 2026, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2025, to the projected average 2026 plant balance. The average balance for the twelve months ended September 30, 2026, is computed in columns 2 through 7 of Table 3 and is based on the projected additions, retirements, and transfers in columns 3 through 5.

Q. With reference to Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2020, through September 30, 2025.

Q. Please explain the manner in which you projected the retirements, salvage, and removal costs that are shown in columns 5, 6, and 7 of Table 2.

A. Retirements were projected by plant account by applying the average retirement ratio, expressed as a percent of additions, for the five fiscal years 2021 through 2025, to FTY and FPFTY additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal ratios, expressed as a percent of retirement amounts, for the five years 2021 through 2025, to the projected retirement amounts.

Q. Was the book reserve as of September 30, 2027, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2027 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2027.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $182,262,215 and consists of $172,559,378 of annual accruals to recover original cost and $9,702,837 of net salvage amortization. These amounts are set forth in column 8 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $182,262,215?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of compiling historical data from records related to UGI Gas's gas plant; analyzing these data to obtain historical trends of

survivor characteristics; obtaining supplementary information from engineering management and operating personnel concerning UGI Gas's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of UGI Gas's gas plant?

A. The data consisted of the entries made by UGI Gas to record gas plant transactions during the period 1951 through 2022. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate method when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve and were not used.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the

several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Gas Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves (“Iowa curves”). The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, as well as the remaining 49 states, and have been for many years.

Iowa curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system, and the

relative height of the mode. For example, the Iowa 35-R2 curve indicates an average service life of thirty-five years; and a Right-skewed, or R, type curve (the mode or highest frequency of retirements occurs after average life for right modal curves). It also provides a relatively low height, 2, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the Commission every five years, at a minimum. UGI Gas's most recent service life study report was performed in 2023 using plant accounting data through September 30, 2022. Facilities visited during field trips generally include representative city gate stations, district regulating stations, service centers, office buildings, training centers, etc. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth on Table 1 of UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

Q. Please briefly describe the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please briefly describe the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please briefly describe the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please briefly describe the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397, and 398 include a very large number of units but represent a very small percent of depreciable gas plant.

Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired per books when the age of the vintage reaches the amortization period.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the manner in which the study was conducted. Account 376.1 represents 13 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2022. These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes primarily cathodically-protected, steel mains, although some bare steel mains are still in service. As detailed in UGI Gas Exhibit C (Future), the Iowa 75-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The 75-R2.5 is a reasonably good fit of the company's historical plant accounting data, consistent with engineering outlook and within the typical range of service lives used by other gas companies for steel mains. The original life table for the 1951-2022 experience band is set forth on pages VI-22 through VI-27.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service as of September 30, 2025, is presented by vintage in Part VII on pages VII-37 through VII-45 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations as of September 30, 2026, are presented in Part III of Exhibit C (Fully Projected). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 75-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 75-R2.5 survivor curve. The accrued depreciation was derived for each equal life group, based

on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 75-R2.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-45 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 in order to calculate the annual depreciation accrual rate in column 7. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as the straight line method, the average service life, and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an

amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2026, is presented by vintage in Part VII on pages VII-148 and VII-149 of UGI Gas Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-149 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-5 of UGI Gas Exhibit C (Future). A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service as of September 30, 2027, is presented by vintage on pages III-148 and III-149 of UGI Gas Exhibit C (Fully Projected) and summarized in Table 1 on page II-4.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span approach was applied to major structures in Account 390. The life span approach was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

IX. THE NET SALVAGE AMORTIZATION CLAIM

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in CPG's (formerly PPL Gas Utilities Corporation ("PPL Gas")) 2006 rate filing (Docket No. R-00061398) and have been utilized by UGI Gas in their rate cases ever since. This procedure is consistent with how other Pennsylvania public utilities

account for net salvage and is the method used in preparing the Company's ADR submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Gas's annual depreciation expense consists, in part, of $9,702,837 of net salvage amortization. How did you determine that amount?

A. The $9,702,837 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2022 through September 30, 2027. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Gas Exhibit C (Future) and Part IV of UGI Gas Exhibit C (Fully Projected).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the HTY, FTY, and FPFTY, respectively. The response to I-A-6 presents the survivor curves used in the most recent general rate proceeding and the annual accrual rates that resulted from the use of these curves. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected) in the section titled "Cumulative Depreciated Original Cost."

Q. Does this conclude your direct testimony?

A. Yes, it does.

BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 7 – VICKY A. SCHAPPELL
UGI GAS STATEMENT NO. 8 – DYLAN W. D'ASCENDIS
UGI GAS STATEMENT NO. 9 – DARIN T. ESPIGH
UGI GAS STATEMENT NO. 10 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 11 – JOHN D. TAYLOR
UGI GAS STATEMENT NO. 12 – BRIAN J. MEILINGER

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI GAS STATEMENT NO. 7

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as a Senior Manager, Capital Planning by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit VAS-1 to my testimony.

Q. What are your responsibilities as Senior Manager?

A. As Senior Manager, I supervise a team of Analysts responsible for the preparation of the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Corrosion, Marketing, Information Technology ("IT"), and the Building and Grounds Departments. I collaborate with the Vice President of Operations, the Vice President of Global Engineering, the Director of Engineering Design, the Director Sales, the Director of Pipeline System Planning and Optimization, the Director Financial Planning and Analysis and Senior Engineering Managers to monitor annual capital budget performance and

develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI in developing the overall capital spend strategy. In this role, I have also prepared testimony with supporting exhibits and schedules, and sponsored responses to discovery requests for past base rate cases. Also, I am responsible for preparing UGI Gas's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process necessary for managing the Company's accelerated capital investments programs.

Q. Have you previously presented testimony in proceedings before a regulatory agency?

A. Yes. UGI Gas Exhibit VAS-1 contains a list of those proceedings.

Q. What is the purpose of your testimony?

A. My testimony will address the capital planning process used by UGI Gas which supports the plant in service expenditures included in the proposed rates in this proceeding, specifically as related to plant additions for the future test year ending September 30, 2026("FTY"), and the fully projected future test year ending September 30, 2027 ("FPFTY" or "FY2027").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to UGI Gas Exhibit VAS-1, I am sponsoring UGI Gas Exhibit VAS-2. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. CAPITAL PLANNING

Q. What is the total plant in service budget for UGI Gas for the FPFTY that is reflected in the proposed rates?

A. The total budgeted plant additions for UGI Gas for the FPFTY is $507,994,000.

Q. What are the specific project categories included in the capital budget for UGI Gas?

A. UGI Gas has four main categories that make up its capital budgets: (1) replacement and betterment infrastructure; (2) new business; (3) IT; and (4) other capital spending. I will describe each of these categories and the projects associated with them, as well as the total dollars attributable to each category below.

Q. What process does UGI Gas use to develop its capital budget?

A. UGI Gas's capital budget starts by identifying the four critical areas where the Company must make capital investments to maintain safe and reliable service to customers. For each of these budget areas, the Company then identifies all of the projects or categories of projects that are planned to occur in each fiscal year of a two-year forecast. Once those projects are determined, the Company identifies the FERC accounting treatment for each project. In this case, the Company presents them as part of the budgeted plant additions in Exhibit A, Schedule C-2. The process used to develop Exhibit A is further described in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2).

Q. How does Schedule C-2 show plant additions?

A. Schedule C-2 is an accounting presentation based on FERC accounts. For purposes of developing Schedule C-2, budgeted dollars in each budget category are broken out by the

FERC account numbers that drive the accounting for depreciation. Schedule C-2 is split between Distribution Plant and General and Common Plant. The General and Common Plant includes only the distribution portion of the plant additions for UGI Gas.

Q. Have you prepared an exhibit that shows UGI Gas's plant additions broken down by budget project categories?

A. Yes, I have. UGI Gas Exhibit VAS-2 reflects the Company's plant additions broken out by the different project categories for the five-year period from fiscal year 2023 through fiscal year 2027. The exhibit splits the four budget project categories between Distribution Plant and General and Common Plant, consistent with the categories on Schedule C-2. In addition, UGI Gas Exhibit VAS-2 shows a historical comparison of the total budgeted plant placed in service versus actual plant placed in service additions for the three-year period from fiscal year 2023 through fiscal year 2025. I will describe how the Company's performance history supports the reasonableness of the Company's FTY and FPFTY plant additions in greater detail later in my testimony.

Q. Please comment on the presentations shown in UGI Gas Exhibit VAS-2 and Schedule C-2.

A. While the forecasted total plant in service figures match for the FTY and the FPFTY, there is a difference in the presentation of how UGI Gas Exhibit VAS-2 and Schedule C-2 present plant additions, and it is important to understand how these budget presentations align. Specifically, UGI Gas Exhibit VAS-2 shows how the Company's four individual budget categories constitute the Company's total Plant Additions and how they map into

the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows that three of the four budget categories fall into both of the plant categories (i.e., Distribution Plant and General & Common Plant) when describing the budget by FERC accounts. IT projects are the only budget category where projects fall exclusively into one FERC plant account – General and Common Plant – when recorded for accounting purposes.

Q. Why is it important to understand the relationship between the Company's budgeting process and the reflection of the budget in Schedule C-2?

A. When the Company plans for future plant additions, it utilizes a project-based build-up and does not directly budget using the FERC accounts, as work streams do not directly correlate to the format shown in Schedule C-2. When the Company budgets and then executes on its budget, it first looks at the total for the budget category, and then examines its overall budgeted projects on a total additions basis, because its operations and work streams are divided in the same manner to achieve core utility objectives. Ultimately, the Company manages to the total overall budget. As a result of this process, it is more reasonable to review the Distribution and General and Common Plant levels together when considering how the Company performed to its budget, rather than the accounting distinction set forth in Schedule C-2. Thus, to properly compare historical budgeted plant additions to actuals for ratemaking purposes, the Distribution and General and Common Plant additions should be reviewed in total.

Q. Turning to the capital budget categories, what are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace or repair existing infrastructure and include, but are not limited to, leak remediation, pipe relocations, material upgrades, service renewals, reliability improvements, and metering and regulation upgrades.

Q. Please describe the prioritization process that is used to evaluate R&B projects.

A. Projects are prioritized for inclusion in the budget according to the condition of, and risks associated with, existing assets, including those factors affecting safety and reliability. In determining the condition of an existing asset, the Company considers various criteria including, but not limited to the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks, and leakage (as compared to other pipe materials). This comprehensive approach is ultimately utilized which targets the highest risk mains first and incorporates considerations related to the efficient deployment of capital and resources. UGI Gas has also committed to replacing identified priority plastic pipe, in addition to cast iron and bare steel pipe as defined in its Third Long Term Infrastructure Improvement Plan ("LTIIP") as discussed below. Risk evaluations for mains are based on numerous factors, including condition, age, coating, type of ground cover, geographical proximity to structures and prior leak and/or break history. UGI Gas reviews these factors annually to identify the highest risk pipe segments and prioritize them

for replacement.[1] Specifically, commercial risk evaluation software is used in concert with a team of Subject Matter Experts to evaluate, prioritize, and bundle replacement projects. Furthermore, UGI Gas's Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP") provide a detailed listing and weighting of factors considered in the risk-based evaluation, which may cause specific projects to be reprioritized for replacement on a more accelerated basis

UGI Gas's prioritization of projects for its capital budgets is consistent with its DIMP and LTIIP, which is described in more detail in the direct testimony of UGI Gas witness, Jill E. Walter (UGI Gas Statement No. 3). LTIIP replacement investments are identified and prioritized on a risk basis in accordance with UGI Gas's DIMP.

Q. Has there been any update in UGI Gas's priorities for its R&B investments?

A. Yes. As of the end of calendar year 2026, the Company will have completed its cast iron retirement, removing 407 miles from service since this program began in 2013. Beginning in calendar year 2027, the Company shift its R&B focus to bare steel retirement, as well as vintage plastic identification and replacement.

Q. How does UGI Gas determine which R&B projects are included in the capital budget for a given year?

A. UGI Gas's LTIIP guides the formulation of the overall R&B capital budget. Within the

[1] When replacing mains, the Company also replaces associated distribution equipment, including service lines, as well as installing or replacing safety and monitoring devices (excess flow valves), meters, risers, and meter bars. Additionally, indoor meters are relocated to an outside location, except in certain circumstances. Similarly, regulator stations and service regulators are reviewed and prioritized for replacement based on nearby main replacement projects or required upgrades due to the updated equipment installed as part of the main replacement program.

various categories of the LTIIP, R&B projects are selected and prioritized according to the risk-based evaluation process that I described above. The total anticipated budgeted plant additions associated with R&B projects in the FPFTY is $383,642,000 of which $383,135,000 is included in Distribution plant additions and $507,000 is included in General and Common Plant Additions.

Q. What are new business projects?

A. New business projects provide new or upgraded gas service to customers and may involve the installation of new gas mains and services to support conversions to natural gas service (from other heating sources).

Q. Please describe how the new business infrastructure projects are selected for inclusion in the capital budget.

A. The new business portion of the capital budget is developed according to forecasts of new business opportunities, projections of customer conversions, and plans for new construction and development projects. The total anticipated budgeted plant additions associated with new business projects in the FPFTY is $75,690,000; these additions are included in Distribution plant additions.

Q. What are IT projects?

A. IT projects enhance the Company's IT systems in a number of ways. These projects involve hardware and software applications which improve the Company's processes and methods across a wide range of operational concerns or needs, such as capital project

management, cybersecurity, customer communications, billing as well as other areas. Further, these projects facilitate the Company's ability to enter, store, retrieve, and send data and information related to such projects. The total anticipated budgeted plant additions associated with IT projects in the FTY is $43,732,000. Of this amount, $18,818,000 relates to one specific large IT project, Field Services Management ("FSM"), which has a planned in-service date of July 2026as presented in the Company's 2025 Gas Base Rate Case.[2] The total anticipated budgeted plant additions associated with IT projects in the FPFTY is $12,032,000 and these projects are included in General and Common Plant Additions.

Q. Please describe the prioritization process used to evaluate IT projects.

A. IT projects are prioritized for inclusion in the budget based on identified business needs. UGI relies on an IT Prioritization Committee to develop a prioritized budget based on overall business impact, availability of system support, and resource availability. Examples of IT projects include the Pipeline Risk Management – DIMP project that went into service in September 2025. This project focused on standardizing a tool to maintain compliance and mitigate asset risk.

Q. What are Other capital projects?

A. Other capital projects include building-related projects, corrosion control projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land

[2] See the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 5. *See also*, *Pa. PUC v. UGI Gas*, R-2024-3052716 (Recommended Decision issued on August 8, 2025 recommending approval of the Joint Petition for Approval of All Issues without modification). No party challenged the Company's FSM and related IT Plan.

purchases, building improvements/renovations, and the purchase of furniture. Corrosion control projects include upgrades and replacements of cathodic protection systems for mains. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include tapping and stopping equipment, safety tools, and leak detection equipment. Fleet purchases are needed to maintain a reliable mode of transportation for field employees along with certain specialty equipment required to perform daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks, backhoes, excavators, forklifts, and equipment trailers for backhoes and excavators. The total anticipated budgeted plant additions associated with Other projects in the FPFTY is $36,630,000 of which $5,597,000 is included in Distribution plant additions and $31,032,000 is included in General and Common Plant Additions (UGI Gas Exhibit VAS-2).

Q. Please describe the prioritization process used to evaluate Other capital projects.

A. The prioritization process for Other capital projects is specific to the need being addressed. Building-related projects are prioritized for inclusion in the budget based on safety, security, regulatory, or financial and strategic needs. Regulatory driven projects may originate from compliance requirements or certain audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Corrosion control projects involving coated steel main replacements are prioritized for inclusion in the budget according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part

192).[3] Corrosion control projects also may depend on unrepairable leakages or emerging main issues. Capital tool projects are prioritized for inclusion in the budget according to the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the budget based on age, condition, maintenance costs, and mileage of the existing asset.

Q. Please discuss some of the key drivers which support the increase in UGI Gas's FPFTY plant additions as compared to the HTY.

A. The planned capital for FY2027 includes cost increases in R&B associated with complexity, location and size of the remaining bare steel replacement projects, as well as general resource cost increases. It also includes priority plastic pipe as Distribution System Improvement Charge-eligible property that will be replaced through the LTIIP on an accelerated basis to reduce associated leaks and overall risks on the Company's distribution system, as defined in the Company's Third LTIIP at Docket No. P-2024-3050769. The Company's total planned 2027 replacement miles will be 75 to 85 miles. This includes a planned abandonment of a large section of a wrought iron and bare steel line in the northern part of the Company' service territory due to corrosion. This is compared to the approximately 63 miles of cast iron, bare steel and wrought iron main that were removed and replaced in FY2025.

[3] Transmission lines may be replaced due to corrosion that affects wall thickness pursuant to 49 C.F.R. § 192.485. Additionally, portions of transmission lines (with localized corrosion pitting) may be replaced pursuant to 49 C.F.R. § 192.485. Similarly, distribution lines with corrosion (or portions thereof with localized pitting corrosion) may be replaced pursuant to 49 C.F.R. § 192.487. Lines also may need to be replaced if they lack cathodic protection systems, as detailed in 49 C.F.R. § 192.463.

Q. How can UGI Gas's actual in-service plant additions be compared to budgeted in service plant additions historically in order to demonstrate Company performance?

A. As shown in UGI Gas Exhibit VAS-2, over the past three years, the Company's total budgeted in service plant additions were $1,295,956,000, while the total actual in-service plant additions were $1,280,839,000. Thus, UGI Gas's plant in service performance as viewed by variance to budget can be shown to be under 1.2% ($1,295,956,000/$1,280,839,000) over the three-year period. UGI Gas Exhibit VAS-2 also shows that over the past five years, the Company's total budgeted in service plant additions were $2,083,368, while the total actual in-service plant additions were $2,085,134. Thus, UGI Gas's plant in service performance as viewed by variance to budget can be shown to be 0.1% ($2,085,134/$2,083,368) over the five-year period. This close correlation is indicative of the Company's ability to perform in developing a plan for plant additions and reliably executing to that plan. Importantly, the Company manages its budgets in total and as any budget changes are made dollars are reallocated between the four main budget categories, described above, such that the total plant additions align as close as possible to the total plant addition actuals.

Q. What process does UGI Gas utilize when developing its capital budgets?

A. During the Company's annual capital budget process, which occurs during the summer/fall, a two-year budget is prepared. The first year of the capital budget is the basis for the FTY. The second year is a preliminary budget and is the basis for the FPFTY. During the budget process, project managers estimate the total project costs and budgeted in-service dates at the project level based on the current data available. These estimated in-service dates are

the basis for the budgeted plant additions as further discussed in the testimony of UGI Gas witness Amy M. Keller (UGI Gas Statement No. 5). As the Company transitions from one budget year to the next, and the preliminary budget year becomes the active budget year, the Company makes certain adjustments to its budget for known and measurable changes in the assumptions about operating conditions that supported the preliminary budget. For example, the Company adjusts its project lists on an annual basis based on operational demands, such as the need to reprioritize projects based on emerging service needs or unanticipated equipment condition changes.

Q. What metric is utilized by the Company to track plant addition performance?

A. Exhibit VAS-2 compares plant additions placed in service (i.e., actuals) to the budgeted plant additions between 2023 and 2025 in order to track actual plant addition performance. The exhibit provides these figures by the four above-described budget categories. It also separates them by Distribution Plant and General and Common Plant. Taken together, the Distribution and General and Common Plant categories calculate total Plant Additions. Finally, the exhibit calculates the plant in service as a percent of budget metric for each year and over the three-year period by dividing actuals by budgets.

Specifically, during this three-year period, the Company's plant additions averaged 98.8% of its budget. The percentage of plant additions is calculated by dividing the actual plant additions by the budgeted plant additions (Actual / Forecast). This close correlation between budgeted and actual plant placed in service over a three-year period shows that UGI Gas's budget process is very effective at identifying its required plant additions, and UGI Gas's capital deployment and management activities perform actual work in near

identical level to budgeted levels. In total, this comparative metric supports the Company's ability to successfully plan and execute on the claimed level of plant in service in this case.

III. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VAS-1

Vicky A. Schappell

Senior Manager – Capital Planning

WORK EXPERIENCE

UGI Utilities, Inc. (Denver, PA)

Senior Manager – Capital Planning	May 2024-Present
Principal Analyst - Capital Planning	January 2020-May 2024
Senior Analyst - Capital Planning	April 2018-January 2020
Senior Supervisor Plant Accounting	December 2014-April 2018
Senior Analyst - General Ledger	September 2011-December 2014
Analyst II – General Ledger	September 2008-September 2011

Teleflex Medical (Reading, PA)

Accounting Supervisor	December 2007-September 2008
Senior Accountant – Financial Reporting	March 2003-December 2007
Staff Accountant – Financial Reporting	October 1999-March 2003

Heffler, Radetich & Saitta, LLP (Philadelphia, PA)

Auditor	May 1997-October 1999

Education

B.S. in Accounting, Shippensburg University,
1997

Previous Testimony

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Gas Base Rate Case	Docket No. R-2021-3030218
UGI Electric Base Rate Case	Docket No. R-2022-3037368
UGI Gas Base Rate Case	Docket No. R-2024-3052716

UGI GAS

EXHIBIT VAS-2

UGI UTILITIES, INC. - GAS DIVISION
Plant Additions Placed in Service Compared to Budget
$ amounts in '000s

Description	Budget 2025	Actual 2025	Budget 2024	Actual 2024	Budget 2023	Actual 2023	Budget 2022	Actual 2022	Budget 2021	Actual 2021	5 Year Total Budget	5 Year Total Actual	3 Year Total Budget	3 Year Total Actual
Natural Gas Production														
Replacement and Betterment										(207)	-	(207)	-	-
Subtotal Natural Gas Production	-	-	-	-	-	-	-	-	-	(207)	-	(207)	-	-
Transmission Plant														
Replacement and Betterment		698		(3)		(241)		(53)		305	-	706	-	454
Growth		142						(239)		239	-	142	-	142
Other		112				(71)		90		(10)	-	120	-	40
Subtotal Transmission Plant	-	952	-	(3)	-	(313)	-	(202)	-	534	-	968	-	636
Distribution														
Replacement and Betterment	315,140	290,910	259,662	243,367	317,228	302,171	281,270	293,795	247,853	229,239	1,421,153	1,359,483	892,030	836,449
Growth	67,447	77,260	67,452	68,926	67,961	92,260	69,493	77,289	65,503	84,264	337,855	400,000	202,860	238,446
Other	6,731	3,955	4,750	5,202	6,100	6,896	7,248	5,573	6,350	5,165	31,178	26,791	17,580	16,053
IT											-	-	-	-
Subtotal Distribution	389,317	372,126	331,864	317,496	391,289	401,327	358,011	376,657	319,706	318,668	1,790,187	1,786,273	1,112,469	1,090,948
General and Common Plant														
Replacement and Betterment	377	1,100	554	838	341	255	178	339	220	437	1,671	2,969	1,272	2,193
Growth	-									1	-	1	-	-
Other	17,132	22,656	33,504	34,384	52,960	48,386	26,375	30,937	58,650	46,404	188,620	182,768	103,595	105,426
IT	12,665	11,289	15,539	23,630	50,414	46,717	13,839	15,091	10,433	15,632	102,890	112,359	78,619	81,635
Subtotal General and Common Plant	30,174	35,044	49,598	58,852	103,715	95,358	40,392	46,368	69,302	62,474	293,181	298,096	183,487	189,255
Total Plant Additions	419,491	408,122	381,462	376,346	495,003	496,372	398,404	422,823	389,008	381,469	2,083,368	2,085,131	1,295,956	1,280,839
	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
Plant Additions Placed in Service as % of Budget	**(2) / (1)**	**97.3%**	**(2) / (1)**	**98.7%**	**(2) / (1)**	**100.3%**	**(2) / (1)**	**106.1%**	**(2) / (1)**	**98.1%**	**(2) / (1)**	**100.1%**	**(2) / (1)**	**98.8%**

Forecasted Performance

Description	FPFTY Budget 2027	FTY Budget 2026
Distribution		
Replacement and Betterment	383,135	311,002
Growth	75,690	74,698
Other	5,597	10,061
Subtotal Distribution	464,423	395,762
General and Common Plant		
Replacement and Betterment	507	524
Growth		
Other	31,032	30,565
IT	12,032	43,732
Subtotal General and Common Plant	43,572	74,820
Total Forecasted Plant Additions	507,994	470,582

UGI GAS STATEMENT NO. 8

DYLAN W. D'ASCENDIS

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Dylan W. D'Ascendis

Topics Addressed: **Return on Equity**

Dated: January 28, 2026

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DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003. I am a Partner at ScottMadden, Inc.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. I have offered expert testimony on behalf of investor-owned utilities before over 40 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the National Energy Regulator in Canada, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization-weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst"

by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are included in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. The regulatory commissions before whom I have testified are identified in Appendix A.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to present evidence and provide the Pennsylvania Public Utility Commission ("Commission") with a recommendation regarding UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company") return on common equity ("ROE") for its natural gas distribution operations, and to provide an assessment of the capital structure to be used for ratemaking purposes. My testimony relies upon Company records, public documents, my personal knowledge and education, and my professional experience.

Q. HAVE YOU PREPARED ANY EXHIBITS OR SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. My analyses and conclusions are supported by the data presented in Exhibit B as Schedules DWD-1 through DWD-10, which have been prepared by me or under my direct supervision and control.

Q. WHAT IS YOUR RECOMMENDED COMMON EQUITY COST RATE?

A. I recommend that the Commission authorize UGI Gas the opportunity to earn an ROE of 10.75% on its jurisdictional rate base, based on its actual capital structure. The Company's requested capital structure consists of 45.75% long-term debt, at an embedded debt cost rate of 5.17%, and 54.25% common equity, to which my recommended ROE of 10.75% would apply. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	10.75%	5.83%
Total	100.00%		8.20%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ROE.

A. My recommended ROE of 10.75% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to UGI Gas. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1]

[1] *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*").

and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the Company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of seven (7) natural gas utility companies ("Gas Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a Non-Price Regulated Proxy Group similar in total risk to the Gas Utility Proxy Group. The results derived from each cost of common equity model are as follows:

Table 2: Summary of Common Equity Cost Rate

Discounted Cash Flow Model (DCF)	10.53%
Risk Premium Model (RPM)	10.41% - 10.80%
Capital Asset Pricing Model (CAPM)	10.17% - 11.30%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	10.96% - 11.35%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.17% - 11.35%
Business Risk Adjustment	0.05%
Flotation Cost Adjustment	0.12%
Indicated Range of Common Equity Cost Rates after Adjustment	10.34% - 11.52%
Recommended Cost of Equity	10.75%

[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

As shown in Table 2, the indicated range of common equity cost rates applicable to the Gas Utility Proxy Group is between 10.17% and 11.35%.

After determining the Gas Utility Proxy Group ROE, one must conduct a relative risk analysis to determine whether additional adjustments to the Gas Utility Proxy Group ROE are warranted to reflect the unique risk of the Company. My relative risk analyses show that adjustments to the Gas Utility Proxy Group indicated range of ROEs to reflect the Company's unique business risks are necessary. From the indicated range of ROEs after adjustment, I recommend the Commission approve a specific ROE of 10.75% for the Company's jurisdictional rate base.

III. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.75%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting

[3] *Hope*, 320 U.S. 591 (1944), at 603.

process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective, as measured by its combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing (i.e., financial risk) of the Company's utility subsidiary on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (i.e., the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process should provide the utility a reasonable opportunity to recover its return of, and return on, its reasonably incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (e.g.,

management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.[4]

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies, the vagaries of weather, and the like, all of which have a direct bearing on earnings.

[4] As will be discussed later in this testimony, another definition of total risk is systematic risk plus unsystematic risk.

Although analysts, including ratings agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Gas Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

IV. UGI GAS AND GAS THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH UGI GAS'S OPERATIONS?

A. Yes. UGI Gas provides natural gas utility service to over 706,000 customers in certificated portions of 46 eastern and central Pennsylvania counties. UGI Utilities, Inc. holds an A3

[5] Risk distinctions within S&Ps bond rating categories are recognized by a plus or minus, *e.g.*, an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, *e.g.*, a Moody's rating can be A1, A2 and A3.

rating from Moody's, and is not rated by S&P. The Company is not publicly traded, as it is an indirectly owned operating subsidiary of UGI Corporation ("UGI Corp."). UGI Corp. is publicly traded on the NYSE under ticker symbol UGI.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Gas Utility Proxy Group, and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Gas Utility Proxy Group.[6]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. Therefore, it is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Gas Utility Proxy

[6] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V.

Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Gas Utility Proxy Group's indicated results.

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN THE GAS UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line Investment Survey's Standard Edition* as of August 22, 2025 ("*Value Line*");

(ii) They have 60% or greater of fiscal year 2024 total operating income derived from, and 60% or greater of fiscal year 2024 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2024 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share growth rate projections; and

(vii) They have *Value Line*, Zacks, or S&P Capital IQ consensus five-year earnings per share growth rate projections.

The following seven companies met these criteria:

Table 3: Utility Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX

V. CAPITAL STRUCTURE

Q. WHAT IS UGI GAS'S REQUESTED CAPITAL STRUCTURE?

A. UGI Gas's requested ratemaking capital structure consists of 45.75% long-term debt and 54.25% common equity.

Q. WHAT ARE THE TYPICAL SOURCES OF CAPITAL COMMONLY CONSIDERED IN ESTABLISHING A UTILITY'S CAPITAL STRUCTURE?

A. Common equity and long-term debt are commonly considered in establishing a utility's capital structure, because they are the typical sources of capital financing a utility's rate base.

Q. PLEASE EXPLAIN.

A. Long-lived assets are typically financed with long-lived securities, so that the overall term structure of the utility's long-term liabilities (both debt and equity) closely match the life of the assets being financed. As stated by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term

sources.[7]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of thirty (30) years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base. Common equity, on the other hand, is outstanding into perpetuity. Thus, common equity more accurately matches the life of the going concern of the utility, which is also assumed to operate in perpetuity. Consequently, it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Q. HOW DOES THE COMPANY'S REQUESTED COMMON EQUITY RATIO OF 54.25% COMPARE WITH THE COMMON EQUITY RATIO MAINTAINED BY THE GAS UTILITY PROXY GROUP?

A. As shown on page 2 of Schedule DWD-2, common equity ratios range from 39.40% to 60.96% for fiscal year 2024 for the Gas Utility Proxy Group. I also considered *Value Line* projected capital structures for the utilities for 2028-2030. That analysis shows a range of projected common equity ratios between 44.00% and 60.00%.[8]

In addition to comparing the Company's requested common equity ratio with common equity ratios currently maintained by the Gas Utility Proxy Group, I also compared the Company's common equity ratio with the equity ratios maintained by the operating subsidiaries of the Gas Utility Proxy Group. As shown on page 3 of Schedule

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[7] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

[8] See, pages 2 through 8 of Schedule DWD-3.

DWD-2, common equity ratios of the operating utility subsidiaries of the companies in the Gas Utility Proxy Group range from 47.86% to 59.93% for fiscal year 2024, for the Gas Utility Proxy Group's operating subsidiaries. The Company's requested common equity ratio of 54.25% is reasonable and consistent with the range of common equity ratios maintained by the operating utility subsidiaries of the Gas Utility Proxy Group.

Q. GIVEN THE RANGE OF EQUITY RATIOS PRESENT WITHIN THE UTILITY PROXY GROUP, IS UGI GAS'S REQUESTED EQUITY RATIO OF 54.25% APPROPRIATE FOR RATEMAKING PURPOSES?

A. Yes, it is. The Company's requested equity ratio of 54.25% is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained, and expected to be maintained, by the Gas Utility Proxy Group and its operating subsidiaries.

VI. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. While a public utility operates a regulated business within the states in which it operates, it still must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET-BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I applied to the Gas Utility Proxy Group described above. I also applied these same models to the Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights into investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Gas Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple

generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The use of multiple models also makes intuitive sense when we consider that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. We cannot assume a single method is the best measure of the factors motivating those decisions for all investors at all times. Giving undue weight to a single method runs the very real risk of ignoring important information provided by other methods.

In other words, no single model is more reliable than all others under all market conditions. Intuition suggests it is more appropriate to use as many methods as we reasonably can and to reflect the many factors motivating investment decisions as best we can. In this instance, intuition, financial theory,[9] and financial practice reach a common conclusion: we should apply and reasonably consider multiple methods when estimating the ROE.

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived

[9] As Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, i.e., the total common equity return rate expected by investors.

$$K_e = (D_0 (1+g))/P + g$$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of October 31, 2025, divided by the average closing market price for the 60 trading days ended October 31, 2025.[10]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Gas Utility Proxy Group increase

[10] *See,* Column 1, page 1 of Schedule DWD-3.

their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE GAS UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and S&P Capital IQ. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of earnings per share growth in my DCF analysis.

Over the long run, there can be no growth in dividends per share without growth in earnings per share. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. The results of applying the DCF model to the Gas Utility Proxy Group are shown on page 1 of Schedule DWD-3 and in Table 4, below:

Table 4: DCF Model Results for the Utility Proxy Group

Mean	10.35%
Median	10.71%
Average of Mean and Median	10.53%

In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Gas Utility Proxy Group, I relied on an average of the mean and the median results of the DCF, specifically 10.53% applicable to the Gas Utility Proxy Group. This approach takes into consideration all proxy company results while mitigating high and low side outliers of those results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 5.49% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the first calendar quarter of 2027, and *Blue Chip Financial Forecast's* ("*Blue Chip*") long-term projections for 2027 to 2031, and 2032 to 2036. As shown on line 1, page 1 of Schedule DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.10%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.39%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[11] Adding that recent 0.39% spread to the expected Aaa-rated corporate bond yield of 5.10% results in an expected A2-rated public utility bond yield of 5.49%. Since the Gas Utility Proxy Group's average Moody's long-term issuer rating is A3, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of

[11] As shown on line 2 and explained in note 2, page 1 of Schedule DWD-4.

0.07%, which represents one-third of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the prospective bond yield applicable to an A3-rated public utility bond.[12] Adding the 0.07% to the 5.49% prospective A2-rated public utility bond yield results in a 5.56% expected bond yield applicable to the Gas Utility Proxy Group.

Table 5: Summary of the Calculation of the Gas Utility Proxy Group Projected Bond Yield[13]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.10%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.39%
Adjustment to Reflect the Gas Utility Proxy Group's Average Moody's Bond Rating of A3	0.07%
Prospective Bond Yield Applicable to the Gas Utility Proxy Group	5.56%

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Gas Utility Proxy Group is shown on lines 1 through 8, on page 6 of Schedule DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and combined *Value Line*, Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

[12] As shown on line 4 and explained in note 3, page 1 of Schedule DWD-4.
[13] As shown on page 1 of Schedule DWD-4.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2024. The use of holding period returns over a very long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

The long-term arithmetic mean monthly total return rate on large company common stocks was 12.05% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2024. As shown on line 1 of page 6 of Schedule DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.10%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI - 2023").[14] The use of the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns because the geometric mean relates

[14] SBBI-2023, at 193.

the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 7.13% shown on line 2, page 6 of Schedule DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bond yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. The PRPM, published in the *Journal of Regulatory Economics*,[15] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[16] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is, therefore, highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical returns on large company stocks minus the historical monthly yield on Moody's Aaa/Aa-rated corporate bonds from January 1928 through October 2025. Using a generalized form of ARCH, known as GARCH, I calculated the projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 7.48%.[17]

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[15] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "A New Approach for Estimating the Equity Risk Premium for Public Utilities", The Journal of Regulatory Economics (December 2011), 40:261-278.

[16] Autoregressive conditional heteroscedasticity; see also www.nobelprize.org.

[17] Shown on line 3, page 6 of Schedule DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* SUMMARY & INDEX DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 6 of Schedule DWD-4. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended October 31, 2025, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[18]

The average median expected price appreciation is 40%, which translates to an 8.78% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the market of 10.91%. The forecasted Moody's Aaa-rated corporate bond yield of 5.10% is deducted from the total market return of 10.91%, resulting in an equity risk premium of 5.81%, as shown on line 4, page 6 of Schedule DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P

[18] As explained in detail in note 4, page 6 of Schedule DWD-4.

500 is 17.67%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.10% results in a 12.57% projected equity risk premium as shown on page 6, line 5 of Schedule DWD-4.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all five equity risk premiums based on each source – historical, *Value Line* Summary & Index, and aggregate *Value Line*, Bloomberg, and S&P Capital IQ Market DCF in arriving at a 7.82% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[19]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2024)	6.10%
Regression Analysis on Historical Data	7.13%
PRPM Analysis on Historical Data	7.48%
Prospective Equity Risk Premium using Total Market Returns from *Value Line Summary & Index* less Projected Aaa Corporate Bond Yields	5.81%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	12.57%
Average	7.82%

After calculating the average market equity risk premium of 7.82%, I adjusted it by beta to account for the risk of the Gas Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields.

[19] As shown on page 6 of Schedule DWD-4.

Q. WHAT MEASURES OF BETA DO YOU USE IN DETERMINING YOUR BETA-ADJUSTED EQUITY RISK PREMIUM?

A. I use two measures of beta to calculate my beta-adjusted equity risk premium: (1) the average of *Value Line* and Bloomberg betas; and (2) *Value Line* betas. As will be discussed in detail below, Bloomberg betas may not accurately reflect the risks of the Gas Utility Proxy Group at this time and should be viewed with caution.

Q. WHAT ARE THE BETA VALUES YOU WILL APPLY TO THE MARKET EQUITY RISK PREMIUM?

A. As shown on pages 1 and 2 of Schedule DWD-6, the Gas Utility Proxy Group's average blended beta is 0.61, and its average *Value Line* beta is 0.76. Applying these betas to the market equity risk premium of 7.82% results in equity risk premiums of 4.77% and 5.94%, respectively.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A2-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and one equity risk premium based on the expected returns of the S&P Utilities Index, using *Value Line*, Bloomberg, and S&P Capital IQ data. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.59% and monthly Moody's A2-rated public utility bond yields of 6.42% from 1928 to 2024, to arrive at an equity risk premium of 4.16%.[20] I then used the same historical data to derive an equity risk premium of 5.00% based on a regression of the monthly equity risk premiums. The final S&P Utility

[20] As shown on line 1, page 9 of Schedule DWD-5.

Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to October 2025 to arrive at a PRPM-derived equity risk premium of 4.22% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 11.89% using data from *Value Line*, Bloomberg, and S&P Capital IQ respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.49%.[21] This resulted in equity risk premium of 6.40%. As with the market equity risk premiums, I averaged the four risk premiums to arrive at my utility-specific equity risk premium of 4.95%.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[22]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2024)	4.16%
Regression Analysis on Historical Data	5.00%
PRPM Analysis on Historical Data	4.22%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.40%
Average	4.95%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.84% BASED ON AUTHORIZED ROES FOR NATURAL GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 4.84% shown on page 10 of Schedule DWD-4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds and contains the graphical results of a regression analysis of 852 rate cases for natural gas distribution utilities which were fully litigated during the period from January 1, 1980 through October 31, 2025. It shows the implicit equity risk

[21] Derived on line 4, page 1 of Schedule DWD-4.
[22] As shown on page 9 of Schedule DWD-4.

premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[23] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.49%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.84%.

Q. WHAT IS YOUR CONCLUSION OF THE RANGE OF EQUITY RISK PREMIUMS FOR USE IN YOUR TOTAL MARKET APPROACH RPM FOR THE GAS UTILITY PROXY GROUP?

A. The range of equity risk premiums I applied to the Gas Utility Proxy Group is from 4.85% to 5.24%, which is the average of the beta-adjusted equity risk premium for the Gas Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premium.

[23] *See, e.g.,* Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", Financial Management, Spring 1985, at 33-45.

Table 8: Summary of Conclusions for the Equity Risk Premium for the Gas Utility Proxy Group[24]

Beta-Adjusted Equity Risk Premium	4.77% - 5.94%
S&P Utilities Index Equity Risk Premium	4.95%
Authorized ROE Equity Risk Premium	4.84%
Average	4.85% - 5.24%

Q. WHAT IS THE INDICATED RANGE OF RPM COMMON EQUITY COST RATES BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 1 of Schedule DWD-4, and shown on Table 9, below, I calculated a range of indicated common equity cost rates from 10.41% to 10.80% for the Gas Utility Proxy Group based on the total market approach RPM.

Table 9: Summary of the Total Market Return Risk Premium Model[25]

Prospective Moody's Utility Bond Yield Applicable to the Gas Utility Proxy Group	5.56%
Prospective Equity Risk Premium	4.85% - 5.24%
Indicated Cost of Common Equity	10.41% - 10.80%

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require

[24] As shown on page 5 of Schedule DWD-4.
[25] As shown on page 1 of Schedule DWD-4.

compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
R_s = Return rate on the common stock;
R_f = Risk-free rate of return;
R_m = Return rate on the market as a whole; and
β = Adjusted beta (volatility of the security relative to the market as a whole).

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[26] The ECAPM reflects this empirical reality.

Q. WHY IS THE USE OF THE ECAPM APPROPRIATE IN DETERMINING THE ROE FOR THE COMPANY?

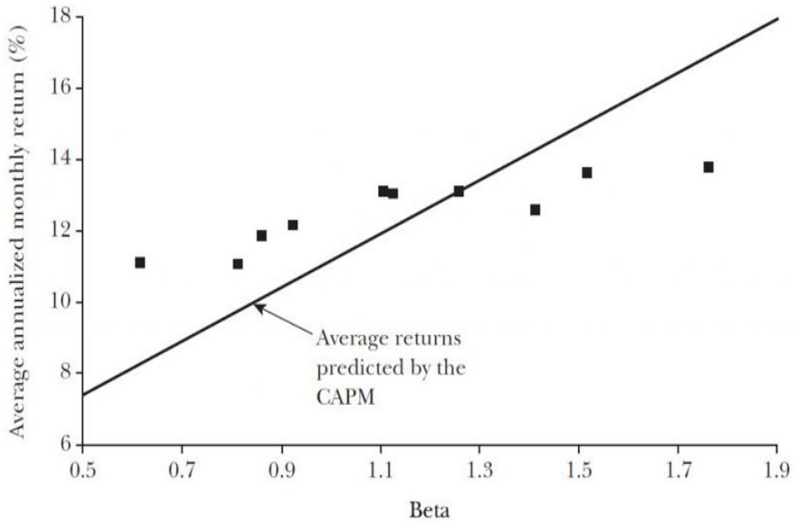
A. The ECAPM is a well-established model that has been relied on in both academic and regulatory settings. Fama & French clearly state regarding Figure 2, below, that "[t]he

[26] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 ("Morin").

returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[27]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[28]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $K = RF + x\,(RM - RF) + (1-x)\ \beta(RM - RF)$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 +

[27] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at 33 ("Fama & French").

[28] Morin, at 207.

0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$[29]

Fama & French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[30]

Finally, Fama & French further note:

> Confirming earlier evidence, the relation between beta and average return `for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[31]

Clearly, the justification from Morin and Fama & French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Gas Utility Proxy Group and averaged the results.

[29] Morin, at 221.
[30] Fama & French, at 32.
[31] Fama & French, at 33.

Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF THE ECAPM?

A. Yes, there is. The empirical issues with the CAPM have been present since the presentation of the model, as noted by Dianna R. Harrington in her text Modern Portfolio Theory & the Capital Asset Pricing Model:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.
>
> * * *
>
> Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:
>
> $$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$
>
> Where:
> R = total returns
> β = the slope of the line (the incremental return for risk)
> α = the intercept or a constant (expected to be 0 over time and across all firms)
> ε = an error term (expected to be random, without information)
> m = the market proxy
> j = the firm or portfolio
> t = the time period
>
> Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable.
>
> On the basis of the CAPM, they expected to find
>
> 1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)

2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformulation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[32]

Harrington discusses Black's potential solution to this phenomenon:

Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:

$$E(R_i) = (1 - \beta_i)\, E(R_z) + \beta_i E(R_m)$$

Where:

E indicates expected,
$E(R_z)$ is less than $E(R_m)$, and
R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.

Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of

[32] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for stocks with betas greater than one and too high for stocks with betas of less than one.[33]

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and Virginia.[34]

Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?

A. As discussed previously, I use: (1) the average of the *Value Line* and Bloomberg betas, which is consistent with prior testimony, and (2) *Value Line* betas. While both *Value Line* and Bloomberg adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg's calculation is based on two years of data.

[33] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 30-31.

[34] The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

Q. WHY ARE YOU PRESENTING YOUR MODEL RESULTS EXCLUSIVELY USING *VALUE LINE* BETAS ALONGSIDE YOUR TRADITIONAL ANALYSIS?

A. I am presenting my updated model results in this way because recent and historical data show that Bloomberg betas may not accurately reflect the risk of the Gas Utility Proxy Group at this time.

Q. HOW DOES BLOOMBERG CALCULATE BETA?

A. As discussed above, beta is the covariance of a stock relative to a market index divided by the variance of the market return. Bloomberg calculates its beta using two years of weekly return data relative to the S&P 500 Index.

Q. WHAT IS A COVARIANCE?

A. A covariance is comprised of two measures: (1) the relative volatility of the stock, which is the standard deviation of the weekly returns of the stock divided by the standard deviation of the weekly return of the index returns;[35] and (2) the correlation of weekly stock and market index returns.[36]

Q. WHAT HAS THE BLOOMBERG BETA BEEN FOR THE GAS UTILITY PROXY GROUP SINCE 2005?

A. As shown in Chart 1, below, the Gas Utility Proxy Group average adjusted beta generally has ranged between 0.60 and 0.90, with some high side exceptions (2007-2008 and 2020-2022) and low side exceptions (2018-2020, second half 2024 – present).

Chart 1: Bloomberg Adjusted beta for the Gas Utility Proxy Group 2005-Present[37]

[35] A relative volatility greater than 1.0 indicates that particular security is more volatile than the market during that calculation period. A relative volatility below 1.0 indicates that the security has less volatility than the market over that calculation period.

[36] Correlations range from negative one to positive one. The closer the correlation is to zero the weaker the relationship. Positive values indicate a positive correlation, where the values of both variables tend to increase together

[37] Source of Information: Bloomberg Professional Services.

Q. WHAT HAVE THE COMPONENTS OF BETA (I.E., RELATIVE VOLATILITY AND CORRELATION) SHOWN DURING THAT PERIOD?

A. As shown on Chart 2, the Gas Utility Proxy Group's relative volatility was generally above 1.0, indicating higher volatility than the S&P 500. On Chart 3, the two-year rolling correlation between the Gas Utility Proxy Group and the S&P 500 has varied over the period 2005 – 2025.

Chart 2: Relative Volatility for the Utility Proxy Group 2005-Present[38]

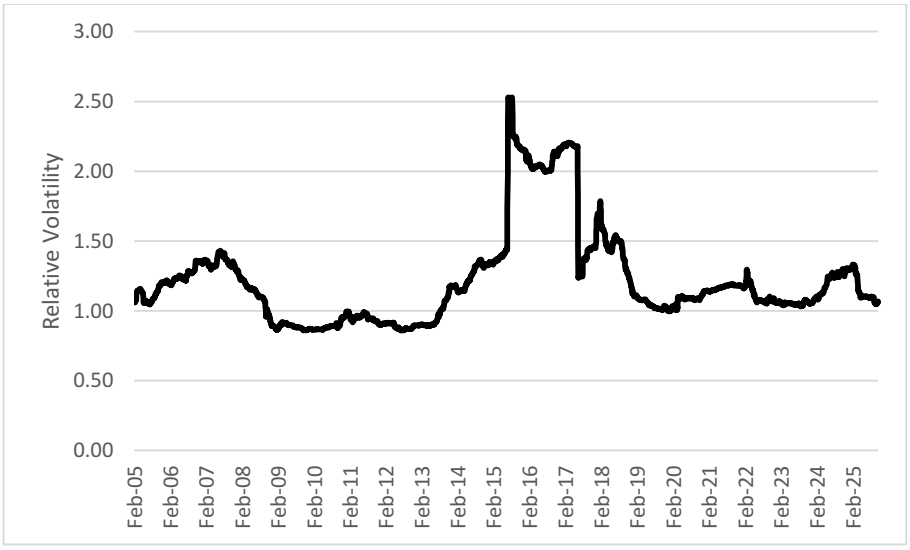
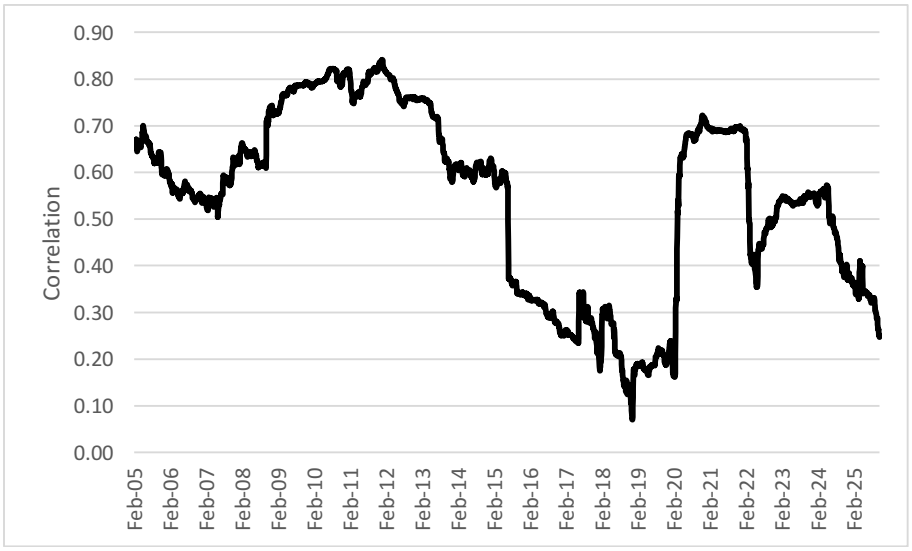


Chart 3: Correlation of the Utility Proxy Group Relative to the S&P 500 Index 2005-Present[39]



Importantly, as shown on Chart 3, during market distress (i.e., the Great Recession and the COVID-19 pandemic), the correlation of the Gas Utility Proxy Group returns and the S&P 500 returns approached 1.0, showing that utilities, as represented by the Gas

[38] Source of Information: S&P Capital IQ.
[39] Source of Information: S&P Capital IQ.

Utility Proxy Group, do not possess defensive qualities and should not be considered defensive stocks nor are they safe harbor investments in times of market distress.

Q. DOES THE LOWER CORRELATION OF THE GAS UTILITY PROXY GROUP RETURNS RELATIVE TO THE S&P 500 RETURNS ALONE NECESSITATE THE EXCLUSION OR MITIGATION OF BLOOMBERG BETAS?

A. No. Just as the investor required return varies under different market conditions, so do the model inputs. To determine whether Bloomberg's default betas calculated relative to the S&P 500 Index are accurately reflecting the risk of the Gas Utility Proxy Group, I compared them with betas calculated using two years of weekly returns relative to the New York Stock Exchange ("NYSE"). The comparison between two-year S&P 500 and NYSE betas are put forth in Chart 4, below:

Chart 4: Comparison of Two-Year S&P 500 and NYSE Betas for the Gas Utility Proxy Group 2005-Present[40]

[40] Source of Information: Bloomberg Professional Services.

As shown on Chart 4, the two-year S&P 500 and NYSE betas are generally consistent until approximately 2024, when the spread between them expanded beyond historical ranges as shown on Chart 5, below:

Chart 5: Spread Between Two-Year S&P and NYSE Betas for the Gas Utility Proxy Group 2005-Present[41]

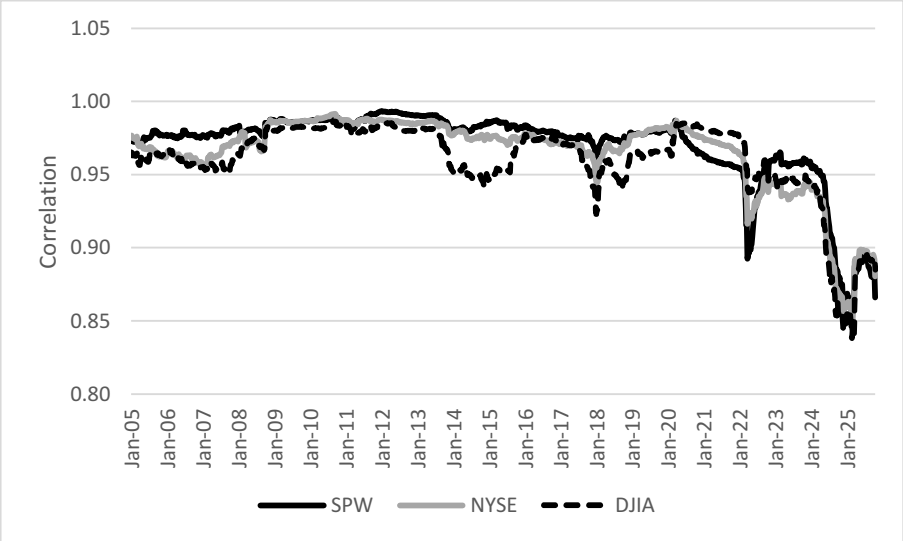
In view of Chart 5, it is clear that the relationship between the S&P 500 and NYSE is dislocated. To determine which index was distorting the risk of the Gas Utility Proxy Group, I compared the S&P 500 returns with those of the NYSE and other market indices.

Q. WHICH MARKET INDICES DID YOU USE IN YOUR COMPARISON?

A. In my comparison, I ran correlations between the returns of the S&P 500 and three other market indices: (1) the NYSE; (2) the Dow Jones Industrial Average ("DJIA"); and (3) the S&P 500 Equal Weighed Index ("SPW"). I ran the correlations for the same 2005-2025 period in the prior charts, which is put forth in Schedule DWD-5 and Chart 6, below:

[41] Source of Information: Bloomberg Professional Services.

Chart 6: Correlation between the S&P 500 Relative to Various Market Indices 2005-Present[42]



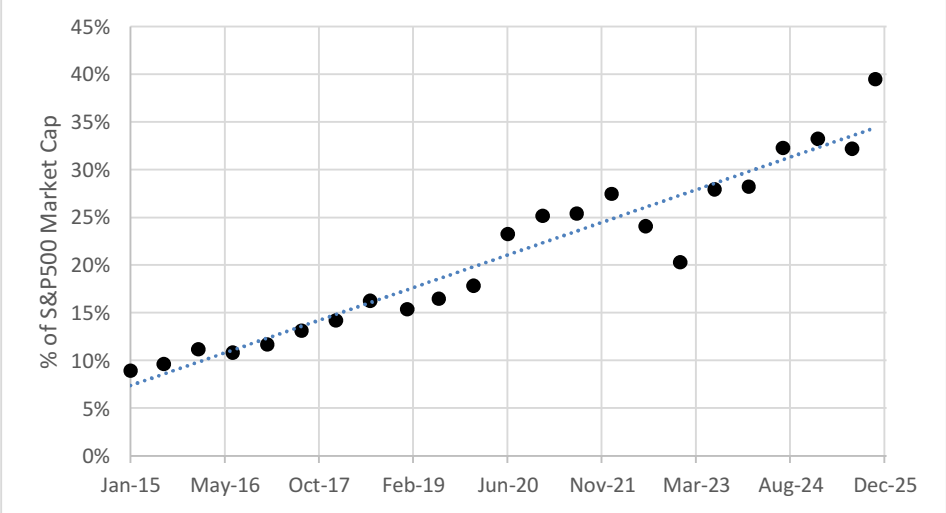
As shown in Chart 6, the two-year rolling correlation between S&P 500's returns and the other market indices' returns generally ranged between 0.95 and 1.00 for the entire period but has recently dipped below 0.85 for each of the measures, indicating that the relationship between the S&P 500 and the other market indices are strained. As shown on pages 2 through 4 of Schedule DWD-5, the two-year rolling correlations of the other market indices are within historical boundaries, whereas, as shown in Chart 6, the correlation in returns between the S&P 500 and the other three indices dropped below 0.90 for an extended period of time. Stated differently, the recent relationship between the S&P 500 Index and the other market indices is inconsistent with their historical relationships while the other market indices have maintained their historical relationships with each other.

[42] Source of Information: Bloomberg Professional Services.

Q. WHY IS THE RELATIONSHIP BETWEEN THE S&P 500 AND OTHER MARKET INDICES DEGRADING?

A. I believe that the concentration of the "Magnificent Seven"[43] ("Mag7") as a percentage of the S&P 500 market capitalization could explain why the two-year rolling correlations between the S&P 500 and the other market indices are degrading. Since 2015, the Mag7 stocks' percentage of the S&P 500 market capitalization has increased from 8.91% to 39.46% as shown on Chart 7, below:

Chart 7: Magnificent Seven Stocks Percentage of S&P 500 Market Capitalization 2015-Present[44]



Q. DOES THE CONCENTRATION AFFECT THE CALCULATION OF BETA FOR THE GAS UTILITY PROXY GROUP?

A. Yes, it does. I evaluated the two-year rolling correlation between the Utility Proxy Group's weekly returns and those returns for the Mag7 and the remaining 493 companies that comprise the S&P 500 index. As shown on Table 10, below, the Gas Utility Proxy

[43] The "Magnificent Seven" stocks are: (1) Apple, Inc.; (2) Amazon.com, Inc.; (3) Alphabet, Inc.; (4) Meta Platforms, Inc.; (5) Microsoft Corporation; (6) NVIDIA Corporation; and (7) Tesla, Inc.

[44] Source of Information: Bloomberg Professional Services.

Group's returns had a **negative** 0.1346 correlation with the Mag7 returns and a **positive** 0.1810 correlation with the rest of the S&P 500, indicating opposite relationships between the Gas Utility Proxy Group and the two subsets of the S&P 500.

Table 10: Correlation between the Gas Utility Proxy Group's Weekly Returns and those of the Magnificent Seven Stocks and the Remaining 493 Component Companies of the S&P 500 October 31, 2025[45]

	Correlation Coefficient 10/31/2025	
	Mag7	Remaining 493
Utility Proxy Group Weekly Returns	-0.1346	0.1810

Given the disconnection of the relationship between the Mag7 and the remaining members of the S&P 500 Index relative to the Gas Utility Proxy Group, the concentration of the Mag7 stocks within the S&P 500 Index, and the S&P 500's degrading relationship to other market indices, Bloomberg betas do not accurately reflect the risk of the Gas Utility Proxy Group as compared to the market, and therefore should be viewed with caution.

Q. PLEASE SUMMARIZE YOUR REASONING AS IT PERTAINS TO YOUR USE OF BETA IN YOUR ANALYSIS.

A. While the cost of capital and the inputs to cost of capital models vary based on market conditions, these variations should not lead an analyst to eliminate or mitigate a specific input. After investigating historical relationships between betas calculated relative to the S&P 500 and NYSE and the relative volatility and correlation of those betas, I discovered that these relationships are currently not within historical ranges and needed to be investigated further. I then compared returns for the S&P 500 to those of the NYSE, SPW, and DJIA, and discovered that those relationships also have departed from historical benchmarks. Importantly, the NYSE, SPW, and DJIA continue to show high levels of

[45] Source of Information: S&P Capital IQ.

correlation with each other. I then investigated the companies that comprised the S&P 500 and found that the Mag7 stocks' return now has an outsized influence on the return on the S&P 500. Looking at the correlations of Gas Utility Proxy Group returns related to Mag7 stocks and the remaining 493 stocks that comprise the S&P 500 Index, I discovered opposite relationships (i.e., negative correlation with Mag7 stocks and positive correlations with the remaining 493 stocks). Given the above, I believe that using the S&P 500 Index to calculate betas may not accurately reflect the risk of the Gas Utility Proxy Group and therefore should be viewed with caution. To reflect this in my analysis, I present my analysis using my traditional application of the models as presented in prior testimonies in Pennsylvania and elsewhere, and also present my model results exclusively using *Value Line* betas, which are calculated relative to the NYSE.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Schedule DWD-6, the risk-free rate for both the applications of the CAPM is 4.53%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2027, and long-term projections for the years 2027 to 2031 and 2032 to 2036.

Q. WHY DID YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed

fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSIS.

A. The basis of the market risk premium is explained in detail in note 1 on page 3 of Schedule DWD-6. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premium, and one *Value Line*, Bloomberg, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government securities of 12.29% was deducted from the monthly historical total market return of 4.99%, which results in an historical market equity risk premium of 7.31%.[46] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government Securities. That regression analysis yielded a market equity risk premium of 7.96%. The PRPM market equity risk premium is 8.35% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through October 2025.[47]

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 4.53%, discussed above, from the *Value Line* projected total annual market return of 10.91%, resulting in a forecasted total market equity risk premium of 6.38%.

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[46] SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional Services.

[47] As shown on page 3 of Schedule DWD-6.

The S&P 500 projected market equity risk premium using *Value Line*, Bloomberg and S&P Capital IQ data is derived by subtracting the projected risk-free rate of 4.53% from the projected total return of the S&P 500 of 17.67%. The resulting market equity risk premium is 13.14%.

These five market risk premium measures, when averaged, result in an average total market equity risk premium of 8.63%.

Table 11: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[48]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2024)	7.31%
Regression Analysis on Historical Data	7.96%
PRPM Analysis on Historical Data	8.35%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	6.38%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.14%
Average	8.63%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE GAS UTILITY PROXY GROUP?

A. As shown on page 1 and 2 of Schedule DWD-6, the average of the mean and median CAPM result using my traditional approach is 10.17%. The average of the mean and median CAPM using only *Value Line* betas is 11.30%. Given the above, a reasonable range of CAPM cost rates is from 10.17% to 11.30%.

[48] As shown on page 3 of Schedule DWD-6.

D. Common Equity Cost Rates for Proxy Group of Domestic, Non-Price Regulated Companies based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Gas Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Gas Utility Proxy Group, since all of these companies compete for capital in the exact same markets. Moreover, *Hope* and *Bluefield* cases do not specify that comparable risk companies had to be utilities.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Gas Utility Proxy Group, I relied on betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). As shown on Schedule DWD-7, these selection criteria resulted in a proxy group of thirty-two domestic, non-price regulated firms comparable in total risk to the Gas Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Gas Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Gas Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, THE RPM, AND THE CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums.

Page 2 of Schedule DWD-8 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Gas Utility Proxy Group, is 11.29%.

Pages 3 through 5 of Schedule DWD-8 contain the data and calculations that support the range of indicated RPM common equity cost rates from 10.94% to 11.64%.

As shown on line 1, page 3 of Schedule DWD-8, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the first quarter of 2027, and for the years 2027 to 2031 and 2032 to 2036, is 5.89%.[49] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of A3, another adjustment to the expected Baa2-rated public utility bond is needed to reflect the difference in bond ratings. A downward adjustment of 0.19%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated corporate bond yields, is necessary to make the prospective bond yield applicable to an A2-rated corporate bond.[50] Subtracting the 0.19% from the 5.89% prospective Baa2-rated corporate bond yield results in a 5.70% expected bond yield applicable to the Non-Price Regulated Proxy Group.

When beta-adjusted risk premiums of 5.24% and 5.94%[51] relative to the Non-Price Regulated Proxy Group are added to the prospective A2-rated corporate bond yield of 5.70%, the indicated range of RPM common equity cost rates are from 10.94% to 11.64%.

Pages 6 and 7 of Schedule DWD-8 contains the inputs and calculations that support my range of indicated CAPM/ECAPM common equity cost rates from 10.68% to 11.29%.

Q. WHAT IS THE INDICATED RANGE OF COMMON EQUITY COST RATES BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-8, the results of the common equity models applied to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the Gas Utility Proxy Group – are as follows:

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[49] *Blue Chip Financial Forecasts*, June 2, 2025 at 14 and October 31, 2025 at 2.
[50] As shown on line 2 and explained in note 2, page 3 of Schedule DWD-8.
[51] Derived on page 5 of Schedule DWD-8.

Table 12: Summary of Model Results Applied to the Non-Price Regulated Proxy Group[52]

Discounted Cash Flow Model	11.29%
Risk Premium Model	10.94% - 11.64%
Capital Asset Pricing Model	10.68% - 11.29%
Mean	10.97% - 11.41%
Median	10.94% - 11.29%
Average of Mean and Median	10.96% - 11.35%

The average of the mean and median of these models indicate a range of cost rates from 10.96% to 11.35%. While I do not consider these results in determining my recommended range of ROEs, I note that they are comparable to my Gas Utility Proxy Group indicated results.

VII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENTS

Q. WHAT IS THE RANGE OF INDICATED COMMON EQUITY COST RATES PRODUCED BY YOUR ROE MODELS?

A. The range of indicated ROEs produced from my analysis is from 10.17% to 11.35%. The indicated results of the DCF model, RPM, and CAPM fall within that indicated range. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent. Based on these common equity cost results, I conclude that a range of common equity cost rates between 10.17% and 11.35% is reasonable.

[52] As shown on page 1 of Schedule DWD-8.

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Q. IS IT NECESSARY TO CONDUCT A RELATIVE RISK ANALYSIS BETWEEN THE GAS UTILITY PROXY GROUP AND THE COMPANY?

A. Yes. After a proxy group-specific ROE is determined, one must conduct a relative risk analysis to determine whether additional adjustments need to be made to reflect the unique risk of the subject company.

A. Business Risk Adjustment

Q. DOES UGI GAS'S SMALLER SIZE RELATIVE TO THE GAS UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. UGI Gas's smaller size relative to the Gas Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence illustrates that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[53]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[54]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[55] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.** (emphasis added)[56]

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53 Kroll: Cost of Capital Navigator: U.S. Cost of Capital Module, "Size as a Predictor of Equity Returns," at 1.

54 Fama & French, at 25-43.

55 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

56 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of UGI Gas's natural gas distribution operations, including its small size, which is justified and supported above by evidence in the financial literature.

Q. INTERVENING WITNESSES OFTEN CITE A STUDY BY DR. ANNIE WONG FOR THE PROPOSITION THAT THERE IS NO SIZE PREMIUM FOR UTILITIES. DOES THIS STUDY ESTABLISH THAT CONTENTION?

A. No, it does not. In the Wong study, Dr. Wong attempted to relate a change in beta to the size effect. Dr. Wong's beta study is incorrect, as beta is a measure of market risk, whereas size is a company-specific, or diversifiable risk. While betas may contain some measure of diversifiable risk, betas have low explanatory power. As shown in Schedule DWD-10, the R-Squared, which measures the variability of returns applicable to beta, is approximately 0.18 for my Gas Utility Proxy Group, which means approximately 82% of the variation of the Gas Utility Proxy Group's returns are unexplained by beta.

Q. IS THERE ALSO A PUBLISHED RESPONSE TO DR. WONG'S ARTICLE?

A. Yes, there is. In response to Professor Wong's article, *The Quarterly Review of Economics and Finance* published an article in 2003, authored by Thomas M. Zepp, which commented on the Wong article often cited by intervening witnesses. Relative to Dr. Wong's results, Dr. Zepp concluded in the Abstract on page 1 of his article: "Her weak results, however, do not rule out the possibility of a small firm effect for utilities."[57] Dr. Zepp also noted on

[57] Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-582.

page 582 that: "Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[58]

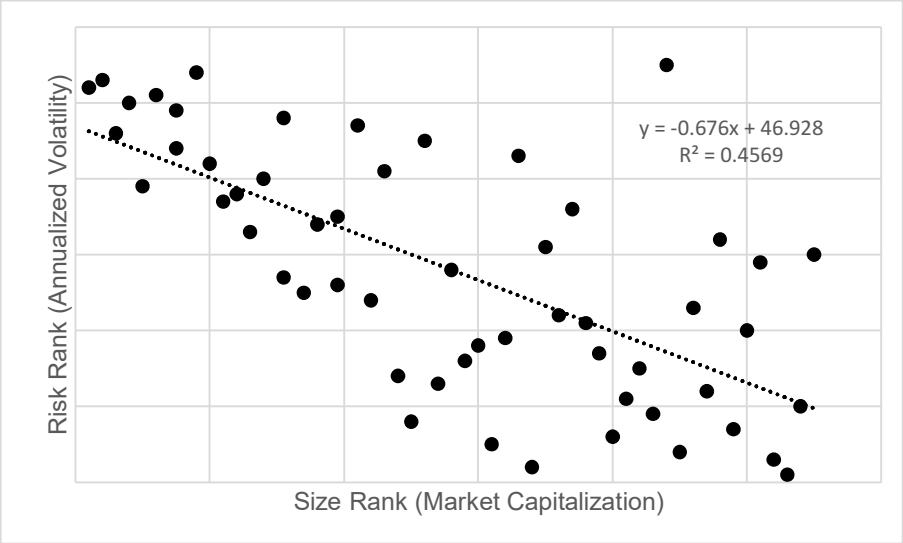
Q. HAVE YOU PERFORMED STUDIES LINKING SIZE AND RISK FOR UTILITY COMPANIES?

A. Yes, I have performed two studies that link size and risk for utility companies. My first study included the universe of electric, gas, and water companies included in *Value Line* Standard Edition. For each of the utilities, the annualized volatility (a measure of risk)[59] was calculated, and each company was ranked by its current market capitalization (a measure of size) as reported by *Value Line*. Ranking the companies by size (smallest to largest) and risk (most risky to least risky), results in the scatterplot shown on Chart 8, below:

[58] Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-583.

[59] Annualized volatility equals the standard deviation of returns over the period multiplied by the square root of 252, or the approximate number of trading days in a year.

Chart 8: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies[60]



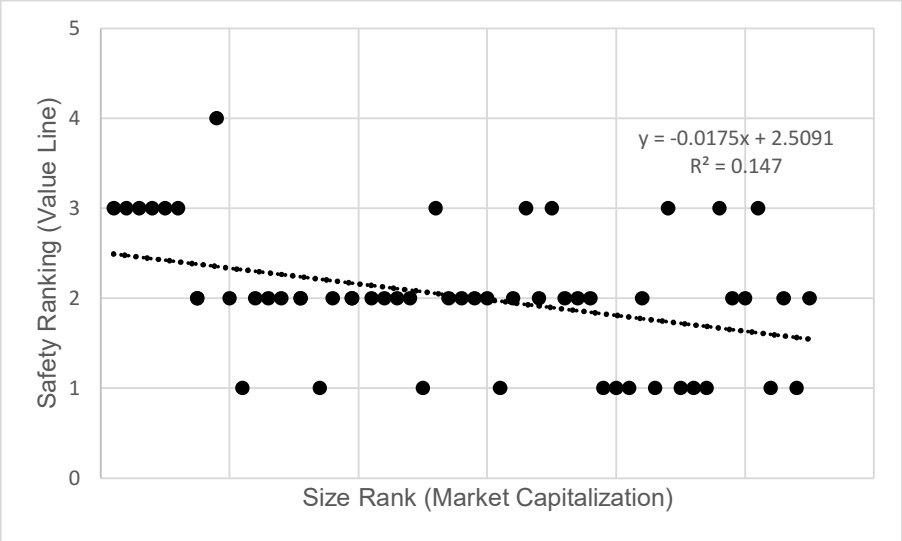
As shown in Chart 8 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

The second study used the same universe of companies, but instead of annualized volatility, I used the *Value Line* Safety Ranking, which is another measure of total risk.[61] After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 9, below:

[60] Source: *Value Line*

[61] *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

Chart 9: Relationship Between Size and Safety Ranking for the *Value Line* Universe of Utility Companies[62]



Similar to the first study, as company size decreases, Safety Ranking degrades, indicating a link between size and risk for utilities. This study is also significant at the 95% confidence level. The assertion that size and risk are not linked for utility companies should be dismissed by the Commission.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO UGI GAS'S GREATER BUSINESS RISK RELATIVE TO THE GAS UTILITY PROXY GROUP?

A. Yes. In the absence of other empirical methods, I compared UGI Gas's and the Gas Utility Proxy Group's relative size, as measured by market capitalization on October 31, 2025.

[62] Source: *Value Line*.

Table 13: Size as Measured by Market Capitalization for the Company and the Gas Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater Than the Company
UGI Gas	$3,901.539	
Gas Utility Proxy Group Median	$ 4,801.525	1.2x
*From page 1 of Schedule DWD-9.		

The Company's market capitalization was at $3.90 billion as of October 31, 2025, compared with the median market capitalization of the Utility Proxy Group of $4.80 billion as of October 31, 2025. The Gas Utility Proxy Group's market capitalization is 1.2 times the size of UGI Gas's market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect UGI Gas's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024 period. The average size premium for the Gas Utility Proxy Group with a market capitalization of $4.80 billion falls in the 5th decile, while UGI Gas's market capitalization of $4.80 billion places the Company in the 6th decile. The size premium spread between the 5th decile and the 6th decile is 0.26%. Even though a 0.26% upward size adjustment is indicated, I conservatively applied a size premium of 0.05% to UGI Gas's indicated range of common equity cost rates.

Q. DOES THIS COMMISSION CONSIDER SIZE IN DETERMINING THE AUTHORIZED ROE?

A. Yes. In Docket No. R-2019-3008212, the Commission stated:

> Based on the evidence of record, we agree with the recommendation of the ALJs that the Company be awarded a DCF cost of common equity which

> is one standard deviation about the average of the mean and median proxy group ROE from the Company's DCF analysis. In so doing, we recognize that the Company's size is a factor in assessing its ability to attract capital. Accordingly, we shall reject Citizens' Exception No. 10, I&E's Exception No. 4, and the OCA's Exception No. 7, consistent with the following discussion.
>
> We are not convinced by the arguments of I&E and the OCA that the ALJs erred in awarding a size adjustment to Citizens'. Rather, we are of the same position as the ALJs that the Company's witness Mr. D'Ascendis offered persuasive record evidence that there is a general inverse relationship between size and risk, such that smaller utilities like Citizens' face greater risk.[63]

Q. WHAT WOULD BE THE ROE RESULT USING THE COMMISSION'S METHOD IN THIS CASE?

A. The average of the mean and median DCF model result is 10.53%, as shown on page 1 of Schedule DWD-3. The standard deviation of those results is 1.51%. Adding the standard deviation to the average of the mean and median DCF result would indicate an ROE of 12.04% for UGI Gas, which is higher than my ultimate recommendation in this case. In view of this, my size adjustment should be considered conservative.

B. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

[63] Pennsylvania Public Utility Commission, Docket No. R-2019-3008212, Opinion and Order, at 103.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free…[Flotation costs] must be recovered through a rate of return adjustment.[64]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during

[64] Morin, at 329.

the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be taken into account. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees, and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on their invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[65] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[66] Consequently, it is proper to include a flotation cost

[65] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

[66] Morin, at 339.

adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. WHAT IS THE IMPACT TO INVESTORS IF THE RECOVERY OF FLOTATION COSTS IS DENIED?

A. Denying recovery of issuance costs penalizes the investors that fund the utility operations. As shown on page 2 of Schedule DWD-11, because of flotation costs, an authorized return of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.65% (i.e., below the required return).[67]

Q. DO YOU AGREE THAT FLOTATION COSTS CAN BE RECOVERED AS AN EXPENSE RATHER THAN AN ADJUSTMENT TO THE ROE?

A. No, I do not. The reason being is due to opportunity cost. When an entity issues equity or debt, the net proceeds of that capital is generally used to finance rate base, which is entitled to a return of (depreciation) and a return on (the weighted average cost of capital). Because the cost of issuing the capital would otherwise go to financing rate base, the costs of that capital would need to be recovered on an ongoing basis.

Q. HAVE OTHER REGULATORY COMMISSIONS ALLOWED FLOTATION COSTS IN THE ALLOWED ROE?

A. Yes, they have. For example, in Peoples Gas System, Inc.'s ("PGS") recent 2023 rate proceeding, the Florida Public Service Commission stated the following regarding my proposed flotation cost adjustment:

> In PGS's last rate case in 2008, we did not make a specific adjustment for flotation costs, but in our order we stated that we have traditionally recognized

[67] Schedule DWD-11, page 2 is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

> a reasonable adjustment for flotation costs in the determination of the investor required return...We find witness D'Ascendis's method to determine the flotation cost is credible and provided persuasive evidence for his recommendation to include a flotation cost of 9 basis points.[68]

Given the above, I recommend this Commission also correctly include flotation costs in the allowed ROE.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by UGI Corp. Based on the issuance costs shown on page 1 of Schedule DWD-11, an adjustment of 0.12% is required to reflect the flotation costs applicable to the Gas Utility Proxy Group.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 0.05% business risk adjustment and the 0.12% flotation cost adjustment to the indicated range of common equity cost rates between 10.17% and 11.35% results in a range of common equity cost rates between 10.34% and 11.52%.[69]

IX. CONCLUSION

Q. WHAT IS YOUR RECOMMENDED ROE FOR UGI GAS?

A. Given the discussion above and the results of my analytical models, I conclude that an appropriate ROE for the Company is 10.75%.

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[68] *In re: Petition for rate increase by Peoples Gas System, Inc.*, Docket No. 20230023-GU, Order Granting in Part and Denying in Part Peoples Gas System, Inc.'s Petition for a Rate Increase, at 68 (December 27, 2023).

[69] A credit risk adjustment is not necessary in this proceeding, as UGI Gas's long-term issuer rating is equivalent to the average long-term issuer rating of the Gas Utility Proxy Group.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.75% FAIR AND REASONABLE TO UGI AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS UGI GAS'S PROPOSED CAPITAL STRUCTURE CONSISTING OF 45.75% LONG-TERM DEBT AND 54.25% COMMON EQUITY FAIR AND REASONABLE?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

for

Dylan W. D'Ascendis

Dylan W. D'Ascendis, CRRA, CVA
Partner
Framingham, MA Office

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 17 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Goat Lake Hydro, Inc.	12/24	Goat Lake Hydro, Inc.	Docket No. TA7-521	Rate of Return
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	09/25	EPCOR Water Arizona, Inc.	Docket No.WS-01303A-24-0130	Annual Formula Rate Adjustment Mechanism
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
Union Pacific Railroad Co – dba Keene Water System	03/25	Union Pacific Railroad Co – dba Keene Water System	Docket No. A25-03-016	Rate of Return
Southwest Gas Corporation	07/24	Southwest Gas Corporation	Docket No. A24-09-001	Return on Equity
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
City of Edmonton, Canada				
EPCOR Water Services, Inc.	05/24	EPCOR Water Services, Inc.	Performance Based Regulation Application	Cost of Capital

Sponsor	Date	Case/Applicant	Docket No.	Subject
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/25	Artesian Water Company, Inc.	Docket No. 25-0436	Rate of Return
Delmarva Power & Light Co.	09/24	Delmarva Power & Light Co.	Docket No. 24-1044 (Gas)	Return on Equity
Tidewater Utilities, Inc.	08/24	Tidewater Utilities, Inc.	Docket No. 24-0991	Rate of Return
Delmarva Power & Light Co.	07/24	Delmarva Power & Light Co.	Docket No. 24-0868	Alternative Forms of Rate Regulation
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	08/24	Washington Gas Light Company	Formal Case No. 1180	Rate of Return
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	03/25	Peoples Gas System, Inc.	Docket No. 20250029-GU	Return on Equity
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Kaupulehu Waste Water Company	02/25	Kaupulehu Waste Water Company	Docket No. 2023-0456	Rate of Return
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/25	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 25-0084 (Gas)	Return on Equity
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/25	Atmos Energy Corporation	26-ATMG-026-RTS	Rate of Return
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
PPL Corporation	05/25	Kentucky Utilities Company / Louisville Gas & Electric Company	2025-00113 / 00114	Rate of Return
Atmos Energy Corporation	09/24	Atmos Energy Corporation	2024-00276	Rate of Return
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy Corporation	06/25	Atmos Energy Corporation	Docket No. 2025-UN-59	Rate of Return
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	5/25	Unitil Corporation	Docket No. DE 25-025	Return on Equity
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	06/25	Middlesex Water Company	Docket No. WR25060372	Rate of Return
Atlantic City Electric Company	11/24	Atlantic City Electric Company	Docket No. ER24110854	Rate of Return
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER23020091	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/25	Carolina Water Service, Inc.	Docket No. W-354, SUB 450	Rate of Return
Aqua North Carolina Inc.	04/25	Aqua North Carolina Inc.	Docket No. W-218, Sub 629	Rate of Return
Pluris Hampstead, LLC	09/24	Pluris Hampstead, LLC	Docket No. W-1305, Sub 38	Rate of Return
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	07/25	Aqua Ohio, Inc.	Case No. 25-0594-WW-AIR	Rate of Return
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Oklahoma Corporation Commission				
Summit Utilities Oklahoma, Inc.	6/25	Summit Utilities Oklahoma, Inc.	Docket No. PUD25-000028	Return on Equity
Pennsylvania Public Utility Commission				
The York Water Company	05/25	The York Water Company	Docket Nos. R-2025-3053442 & R-2025-3053573	Rate of Return
Valley Energy, Inc.	04/25	C&T Enterprises	Docket No. R-2025-3054393	Rate of Return
Wellsboro Electric Company	04/25	C&T Enterprises	Docket No. R-2025-3054392	Rate of Return
Citizens' Electric Company of Lewisburg	04/25	C&T Enterprises	Docket No. R-2025-3054394	Rate of Return
FirstEnergy	04/24	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	06/25	Oncor Electric Delivery Co. LLC	Docket No. 58306	Return on Equity
Aqua Texas, Inc.	06/25	Aqua Texas, Inc.	Docket No. 58124	Rate of Return
CSWR TX Utility Operating Co, LLC	12/24	CSWR TX Utility Operating Co, LLC	Docket No. 57386	Rate of Return
BVRT Utility Holding Co., LLC	07/24	Texas Water Utilities, LP	Docket No. 56664	Rate of Return
Texas Water Utilities, LP	06/24	Texas Water Utilities, LP	Docket No. 56665	Rate of Return
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Texas Division	11/24	Atmos Energy Corporation – Mid-Texas Division	Docket No. OS-24-00019196	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy Corporation – West Texas Division	10/24	Atmos Energy Corporation – West Texas Division	Docket No. OS-24-00018879	Return on Equity
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	07/25	Washington Gas Light Company	PUR-2025-00091	Return on Equity
Aqua Virginia, Inc.	07/25	Aqua Virginia, Inc.	PUR-2025-00071	Rate of Return
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

UGI GAS STATEMENT NO. 9

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 9

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 28, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and professional experience.

A. They are set forth in my resume attached as UGI Gas Exhibit DTE-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2027 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2025 ("HTY") and future test year ending September 30, 2026 ("FTY").

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit DTE-1 contains a list of those proceedings.

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the UGI Gas Exhibits: DTE-1 and DTE-2. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related items. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests as indicated on the master list accompanying this filing.

II. TAX ADJUSTMENTS

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which

includes a presentation for the FPFTY. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the HTY and the FTY. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with adjusted actual book results from the HTY and adjusted FTY results. UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31, include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), Pennsylvania and Local taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the Commission, Office of Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully

Projected), Schedule D-31. The net adjustment of $950,000 is brought forward to Schedule D-3, page 2, line 54.

B. INCOME TAXES

Q. Please discuss the Company's claim for income tax expense.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Gas Exhibit A (Fully Projected), Schedule D-33. Income tax expense is calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state income tax purposes. UGI Gas is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas continues to flow through the repairs tax benefit over the tax useful lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 19 and 20.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 19. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Schedule D-33, line 1 shows revenue at present and proposed rates, while line 2 shows operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI Gas's capital structure

recommended in the direct testimony of Dylan A. D'Ascendis (UGI Gas Statement No. 8) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from operating income before interest and taxes to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9, which appears as ($150,731) on line 10. Next, the statutory state corporate net income tax rate was applied (as further described below in Section G of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Regarding the pro forma federal income tax expense, lines 14 through 19 show the calculation at current and proposed rates. Next, line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates, with the total calculated amount for income taxes, before the application of other adjustments, shown on line 29, which shows the net income tax expense. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Gas?

A. As shown on Schedule D-33 at line 31, the *pro forma* combined income tax expense at present rates is $50.2 million and the *pro forma* income tax expense at proposed rates for the FPFTY is $76.4 million. As explained below in Section E, this figure is not required

to be reduced by a consolidated income tax adjustment. Moreover, the pro forma income tax at present rates and the pro forma income tax revenue increase calculated in Schedule D-33 appear in Schedule D-1, which comprises the Company's claimed income tax expense.

Q. Has the Company reflected the amortization of Excess Deferred Federal Income Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its income tax expense claim?

A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on line 25 of Schedule D-33. The total amortization was approximately $5.2 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30, 2027. This amount is deducted from rate base. The total shown on line 9 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was further reduced by the state regulatory liability associated with UGI Gas's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $716.8 million, which includes the amount related to EDFIT.

Q. Does the Company's reduction to rate base include EDFIT?

A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 9 of Schedule C-6.

Q. Has the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2025-3059523, UGI Gas chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between accelerated tax depreciation

versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Gas has chosen to flow through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

Q. Has UGI Gas adopted the new IRS safe harbor accounting method guidance under Revenue Procedure (Rev. Proc.) 2023-15 for determining qualified repairs deductions?

A Yes, effective for tax year September 30, 2024, UGI Gas adopted the safe harbor method under Rev. Proc 2023-15 for purposes of determining the applicable repairs deduction for tax purposes. These results are the basis for the estimated repairs deductions used in this rate case. The adoption of the new guidance only clarifies what expenditures qualify as tax deductions. There has been no change in the Company's accounting treatment of repair deductions.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a federal consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is also my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. Moreover, it is my understanding that the requirements of Section 1301.1(b) no longer apply pursuant to Section 1301.1(c) as of December 31, 2025. Thus, the Company has not calculated a hypothetical consolidated tax adjustment for purposes of Section 1301.1(b).

F. DEVELOPMENT TAX CREDITS

Q. Does UGI Gas claim a Development Tax Credit on its tax return?

A. Yes, UGI Gas claims a development tax credit on its federal income tax return under Internal Revenue Code Section 41. Qualifying activities for the Development Tax Credit are those that are intended to develop or improve the functionality, performance, reliability, or quality of a new or existing business product, process, technique, formula, invention or software. The activity must be technological in nature, have technical uncertainty and involve a process of experimentation. The credit was first claimed on the Company's federal income tax return for the year ended September 30, 2022, which was filed in 2023. For the purpose of this case, prior years' results were used to estimate the future benefit of the tax credit anticipated in the FPFTY. The benefit of $275,000 is included with the investment tax credit on line 30, of Schedule D-33.

G. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the Pennsylvania corporate net income tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which reduced the state corporate net income tax rate from the then-current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% was effective for tax years beginning in calendar year 2023. Thus, the initial reduction applied to Fiscal Year End September 30, 2024.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 8.49%), FTY (i.e., 7.99%) and FPFTY (i.e., 7.49%). As explained above, the initial reduction applied to our HTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state corporate net income tax rate.

Q. How is the Company applying the Pennsylvania corporate net income tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, the Company's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Manage 1 direct report.

JBS USA, Greeley, CO ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2022-3037368
UGI Gas Base Rate Case	Docket No. R-2024-3052716

UGI GAS

EXHIBIT DTE-2

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2026					$ 708,090
10/31/2026	3,000	335	91.78%	2,753	710,843
11/30/2026	926	305	83.56%	774	711,617
12/31/2026	1,214	274	75.07%	912	712,529
1/31/2027	614	243	66.58%	409	712,938
2/28/2027	646	215	58.90%	380	713,318
3/31/2027	1,728	184	50.41%	871	714,189
4/30/2027	750	154	42.19%	316	714,506
5/31/2027	926	123	33.70%	312	714,818
6/30/2027	3,633	93	25.48%	926	715,743
7/31/2027	2,638	62	16.99%	448	716,192
8/31/2027	1,863	31	8.49%	158	716,350
9/30/2027	7,585	1	0.27%	21	**$ 716,371**

UGI GAS STATEMENT NO. 10

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Sherry A. Epler

Topics Addressed: **Test Year Sales and Revenues**
Tariff Changes

Dated: January 28, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc. ("UGI"). UGI has both a Gas Division ("UGI Gas"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Gas?

A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate administration, including certain interactions with natural gas suppliers under UGI Gas's supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background.

A. Please see my resume, UGI Gas Exhibit SAE-1, which is attached to my testimony.

Q. Please provide your professional experience.

A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment history.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2025 ("HTY"), future test year ending September 30, 2026 ("FTY"), and fully projected future test year ending September 30, 2027 ("FPFTY"); and (2) certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness John D. Taylor, who is employed as Managing Partner by Atrium Economics, LLC (UGI Gas Statement No. 11), is sponsoring allocation of the proposed revenue increase and rate design, in addition to his other testimony topics, using the projected sales and revenue figures discussed in my testimony.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas Exhibit SAE-2 (10 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and Normalized 12-Month Ending Trends of Use Per Customer for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year, Future Test Year, and Historic Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit SAE-8 (No Notice Service ("NNS") Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly Balancing Service ("MBS") Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-

Merchant Function Charge ("MFC") Calculation), certain portions of UGI Gas Exhibit F (Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEAR SALES AND REVENUE

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by incorporating annualizing and normalizing adjustments to the Company's 2027 fiscal year sales and revenue budgets to reflect end of FPFTY conditions for ratemaking purposes. The development of the initial sales and revenue budgets which were utilized as the starting point prior to adjustments is described in the testimony of Vivian K. Ressler (UGI Gas Statement No. 4). Where similar adjustments are made across rate class groups, the methodology applied to develop normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values is the same for all three periods to present sales and revenue on a comparable ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY is included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching occurs on a regular basis between residential Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized

Use/Customer." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2025, were then utilized to mathematically derive the separate Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer regression value).

Actual sales were normalized for Rate R-Non-Heating and Rate RT-Non-Heating, in total, for the 12-month period ended September 30, 2025, to eliminate potential switching impacts that could distort use per customer analyses. These data were used to project combined Rate R/RT-Non-Heating use per customer in total. Weather normalized sales for Rate RT-Non-Heating customers for the 12 months ended September 30, 2025, were then utilized to mathematically derive the separate Rate R-Non-Heating customer values (from the combined Rate R/RT-Non-Heating use per customer value).

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rates N/NT/DS basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." To separate the combined Rate N/NT/DS-Commercial Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Heating use per customer was established on the basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12 months ended September 30, 2025, as this class is much smaller in number than the Rate

N-Commercial Heating class. Rate DS-Commercial Heating use per customer was then established based on budgeted 2027 sales for Rate DS-Commercial Heating, as Rate DS budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS Commercial Heating values were then utilized to mathematically derive the Rate N-Commercial Heating use per customer values (from the combined Rates N/NT/DS-Commercial Heating use per customer value).

Actual sales were normalized for Rate N-Commercial Non-Heating, Rate NT-Commercial Non-Heating and Rate DS-Commercial Non-Heating, in total, to reflect the 12 months ended September 30, 2025, in order to project combined Rates N/NT/DS-Commercial Non-Heating use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Commercial Non-Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Non-Heating was based on weather normalized sales for Rate NT-Commercial Non-Heating, for the 12 months ended September 30, 2025, and Rate DS-Commercial Non-Heating was based on budgeted 2027 sales for Rate DS-Commercial Non-Heating, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate N-Commercial Non-Heating use per customer values (from the combined Rates N/NT/DS-Commercial Non-Heating use per customer value).

Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate DS-Industrial to reflect the 12 months ended September 30, 2025, in order to project combined Rates N/NT/DS-Industrial use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined

Rate N/NT/DS-Industrial value into respective Rate N, Rate NT and Rate DS values, Rate NT-Industrial was based on weather normalized sales for Rate NT-Industrial for the 12 months ended September 30, 2025. Rate DS-Industrial was based on budgeted 2027 sales for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate N-Industrial use per customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days ("HDDs") of 5,218. This annual normal HDD calculation is derived from a composite, sales-weighted value (by system demand) for each of the Company's four delivery regions, and the respective normal heating degree values. As proposed in this proceeding, and discussed in the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11, normal HDDs are now defined based upon an average over a 10-year period with the most recent update of the 10-year period ending December 31, 2024. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 10-year normal HDDs. Please see the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11 for supporting detail on the determination of Normal HDD values and the frequency of Normal HDD updates.

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2027, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2027 budget to develop FPFTY sales and revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is

provided on subsequent worksheets labeled 4(b) through 4(m). In total, these adjustments reflect a decrease to sales of 4,382 MMcf and a decrease to revenue of $49.761 million, inclusive of Purchased Gas Cost ("PGC") revenues.

Q. Please explain the "Adjustment for Customer/Contract Changes" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Customer/Contract Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY; it is inclusive of any large transportation contract customer changes related to customers served under Rates LFD, XD, and IS. In particular, among other adjustments, this adjustment includes a net decrease of 3,925 Residential Heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 1,338 Commercial Heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2027.

Q. How were these adjustments calculated?

A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, these adjustments decrease sales by 834 MMcf and decrease projected revenues by $11.756 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on UGI Gas Exhibit SAE-4(b)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Please explain the adjustment titled "Adjustment for Customer/Contract Changes – Large Transport and Interruptible Detail" as shown on UGI Gas Exhibit SAE-4(b)(1).

A. Adjustments for large transportation customers are developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. The adjustments reflect annualizing anticipated increases or reductions from original individual customer budgeted sales and revenues. Given there were no known changes since the development of the original budget, there are no quantified adjustments to the original budget for the Large Transport and Interruptible customers shown on UGI Gas Exhibit SAE-4(b)(1).

Q. Please explain your next adjustment, "Adjustment for Normalized & Annualized Use/Customer" shown on UGI Gas Exhibit SAE-4(a) and detailed on UGI Gas Exhibit SAE-4(c).

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes usage per customer to projected end-of-test-year levels. Specifically, in developing usage per customer projections for the Company's core Residential Heating rate groups (Rates R and RT), the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) HDDs; (3) lagged HDDs; and (4) weighted time trend. While use per customer, HDDs, and lagged HDDs capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the weighted time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time (*e.g.*,

conservation). These trends can vary, but as a comprehensive variable, "trend" will capture the impacts of conservation, including but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying, and tracking all variables over time, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by HDDs to reflect a "weighted trend," which more accurately reflects that the trends' impacts are directly related to usage during heating time periods.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same base method that the Company has utilized in prior rate cases, updated for the use of a common data set period beginning October 2003 through, now, September 2025. October 2003 is the earliest common data set available for the entire service territory, given the timing and data availability of historic service and former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and UGI CPG.

For the Company's core Commercial Heating rate groups (inclusive of Rates N, NT, and DS), the Company utilized the same regression method as presented in UGI Gas's 2019, 2020, 2022, and 2025 Gas Base Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per

customer; (2) HDDs; and (3) lagged HDDs. For the Commercial Heating group, the Company used the period beginning October 2012 through, now, September 2025 for regression modeling, or the entire period during which common non-residential rate structures existed for UGI Gas and its former subsidiaries.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs, including normal annual HDDs and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In total, the result is a net sales decrease, from the fiscal 2027 budget, of 3,308 MMcf, and a net revenue decrease, from the fiscal 2027 budget, of $37,090 million, inclusive of PGC revenues.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company has continued to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends. Consequently, the multi-year regression period more accurately projects usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last nine base rate cases of UGI Gas and its predecessor entities.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per customer graphs that illustrate the results of both the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short-term normalized ("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month during the 12 month period ending September 30, 2025. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values, thus capturing the ongoing base trend in declining use per customer.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit SAE-4(a) and detailed on UGI Gas Exhibit SAE-4(d).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit SAE-4(a) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2025. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $1.938 million.

Q. Please explain the following three adjustments shown in summary on UGI Gas Exhibit SAE-4(a): "Adjustment for MFC," "Adjustment for USP," and "Adjustment for GPC."

A. The "Adjustment for MFC" annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2025. The MFC Adjustment increases projected revenues by $0.039 million.

The "Adjustment for USP" annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2025. The Adjustment for USP also updates the sales volume for Customer Assistance Program ("CAP") customers in the USP Revenue calculation with end of Fiscal Year 2025 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2024 data. The USP adjustment decreases revenues by $0.480 million.

The "Adjustment for GPC" annualizes the Gas Procurement Cost ("GPC") revenues to reflect the impact of all volume adjustments to the original Fiscal Year 2027 planned budget. The GPC adjustment decreases revenues by $0.257 million. Additional details for these three adjustments are provided in UGI Gas Exhibit SAE-4(e), UGI Gas Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Excess Take" shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI Gas Exhibit SAE-4(h) and reflects the assumption that large transportation customers will

evaluate new service elections and will make the necessary adjustments to avoid Excess Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by $1.7 million.

Q. Please explain "Adjustment for STAS" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for STAS" shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI Gas Exhibit SAE-4(i) and annualizes the revenue for the State Tax Adjustment Surcharge ("STAS") for the FPFTY based on the STAS Rider rate in effect as of December 1, 2025. This adjustment increases revenues by $0.116 million.

Q. Please explain the "Adjustment for EEC Rider" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Rider" annualizes the revenue from the Energy Efficiency and Conservation ("EE&C") Rider ("EEC Rider") for the FPFTY based on the EEC Rider rate in effect as of December 1, 2025. This adjustment decreases revenues by $0.001 million and is detailed on UGI Exhibit SAE-4(j).

Q. Please explain the "Adjustment for EEC Conservation Impact" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Conservation Impact" annualizes the impact to revenues from UGI Gas's ongoing EE&C programs and associated reduced energy consumption as a result of measures implemented as part of the EE&C programs. This adjustment decreases FPFTY sales by 240 MMcf and decreases revenues by $3.000 million as detailed on UGI Gas Exhibit SAE-4(k).

Q. Please explain the "Adjustment for GDE Rider" on UGI Gas Exhibit SAE-4 (a).

A. The "Adjustment for GDE Rider" annualized the revenue for the Gas Delivery Enhancement ("GDE") Rider for the FPFTY based on GDE Rider rate in effect as of December 1, 2025. This adjustment decreases revenues by $0.185 million and is detailed on UGI Gas Exhibit SAE-4(l).

Q. Please explain the "Adjustment for DSIC" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for DSIC**"** annualizes Distribution System Improvement Charge ("DSIC") revenue based on the application of the 0.33% DSIC E-Factor rate in effect as of December 1, 2025, to FPFTY revenues. The FPFTY budget utilized a rate of 0.0%. This adjustment applies a 0.33% DSIC rate in order to annualize the DSIC to end of FPFTY conditions. The 0.33% rate is currently projected to be effective at the end of the FTY, and that 0.33% rate will remain in place through the FPFTY period. This allows the Company to properly quantify DSIC revenues, which will be rolled into the new base rates established in this proceeding as a result of re-setting the DSIC rate to zero pursuant to 66 Pa. C.S. § 1358(b)(1). This adjustment increases revenues by $2.615 million and is shown in detail on UGI Gas Exhibit SAE-4(m).

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes. Pursuant to the terms of the Revenue Sharing Incentive Mechanism in Section 11 of the UGI Gas tariff, these revenues are appropriately treated as below the line for ratemaking purposes and, thus, have been excluded.

III. DEVELOPMENT OF SALES AND REVENUES FOR THE FTY AND HTY

Q. How were normalized and annualized sales and revenues determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for developing the normalized and annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the adjustments that were made in the development of the FPFTY sales and revenues were also made in the development of the FTY sales and revenues, with the exception of the adjustments for the EEC Conservation Impact that are contained in the FPFTY but not the FTY.

Q. How were normalized and annualized sales and revenues determined for the HTY?

A. Historic sales and revenues serve as the starting point for developing the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the Weather Normalization Adjustment ("WNA"), EEC Conservation Impact, GDE Rider, and DSIC. The "Adjustment for WNA" in the HTY removes the revenues associated with the actual WNA revenue recorded in the HTY revenues and margins in order to not double count certain weather-related impacts, as the Adjustment for Normalized & Annualized Use/Customer fully incorporates weather related usage impacts. The EEC Conservation Impact is not required, as the actual HTY sales and revenue reflect such impacts. The adjustments for the GDE Rider and the DSIC are discussed above.

Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice Service)?

A. For the reasoning stated below, the Company is proposing to retain the current Rate NNS service rates at this time and not recalculate those rates. Rate NNS is a daily balancing service offered by the Company. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The revenue generated by Rate NNS charges is reflected as a credit to PGC rates, because the capacity used for this service is otherwise paid for by PGC customers.

Q. How has UGI Gas historically approached the updating of Rate NNS?

A. As part of the settlement of its 2019 Gas Base Rate Case, the parties agreed to a methodology for calculating Rate NNS (see Joint Petition for Approval of Unopposed Settlement of All Issues, paragraph No. 53, filed on July 22, 2019, at Docket Nos. R-2018-3006814, *et al.*, which was approved by the Commission's Opinion and Order entered on October 4, 2019, in that proceeding). In cases since the 2019 Gas Base Rate Case, UGI Gas has used the methodology specified to calculate a rate – consistently a rate decrease – and has proposed that rate decrease in its filed case. In each of those cases, UGI Gas has met strong opposition to its proposal. If the Company were to update the tariffed Rate NNS charge to reflect current cost elements in this case, using the 2019 Gas Base Rate Case methodology, the Company would be proposing a decrease to Rate NNS. However,

as noted above, the Company is proposing to retain the current Rate NNS rate. However, as noted above, the Company is proposing to retain the current Rate NNS rate.

Q. Why is the Company proposing to retain the current Rate NNS rate in this case?

A. UGI Gas believes that the use of the service by customers over time indicates that the current rate, which has been in place since 2019, is appropriately priced for the value it delivers to participating customers, while also providing stable affordability benefits to PGC customers. Importantly, the Company's actions in this regard recognize the historic cost assignment methodology differences between the Company and certain of the public advocates. UGI Gas believes its Rate NNS approach in this proceeding balances the interests of different customer classes.

Q. Has the Company shown the development of the recalculated Rate NNS charge, even though it is not proposing to change Rate NNS?

A. UGI Gas Exhibit SAE-8 shows the recalculation of the Rate NNS charge. Again, this recalculation was developed based on the same methodology used in the Company's 2019 Gas Base Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate would be $0.1700 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to the current NNS rate of $0.2200 per Mcf/d of elected NNA, which was established in the Company's 2022 Gas Base Rate Case (see Paragraph 44 in the Recommended Decision issued on July 28, 2022 at Docket Nos. R-2021-3030218, *et al.*); the current rate was also retained in the Company's 2025 Gas Base Rate Case at Docket No. R-2024-3052716, in Paragraph 55 of the Commission-approved Joint Petition for

Settlement of All Issues dated July 10, 2025. This current rate is proposed to be retained as part of this initial filing.

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the Company's annual 1307(f) proceeding.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in subsequent months.

Q. Has the Company proposed any changes to the Rate MBS rates?

A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result of the settlement in the Company's 2019 Gas Base Rate Case, storage demand charges were included in the calculation of Rate MBS on a 100% load factor basis and the Company is continuing that inclusion in the proposed rates presented. The MBS rate is updated annually on December 1st each year, using 12 months of data ending in September, for the average monthly imbalance utilized in development of the rate. The MBS rates most recently updated for December 1, 2025, are: $0.0177/Mcf for Rates DS and IS; $0.0103/Mcf for Rate LFD; and $0.0104/Mcf for Rate XD. As seen on UGI Gas Exhibit

SAE-9, the proposed MBS rates will be: $0.0198/Mcf for Rates DS and IS; $0.0113/Mcf for Rate LFD; and $0.0116/Mcf for Rate XD. These Rate MBS increases are principally driven by increases to the average capacity charge.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the Company's annual 1307(f) proceeding.

Q. Please describe the GPC.

A. The GPC recovers costs associated with gas procurement that were unbundled from base rates.

Q. Is the Company proposing to update its GPC in this proceeding?

A. No. The Company proposes to continue the $0.0660/Mcf blended rate that was approved in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on October 8, 2020, in that proceeding).

Q. Please describe the MFC.

A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be uncollectible.

Q. Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.37%, and the MFC for the commercial class will be 0.47%. Please see UGI Gas Exhibit SAE-10 for additional details.

Q. Please describe the USP Rider.

A. The USP Rider recovers those costs associated with the provision of universal service offerings approved by the Commission in the Company's Universal Service and Energy Conservation Plan.

Q. Is the Company proposing any changes to the USP Rider?

A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider F – Universal Service Program "USP" to update the threshold number of customers enrolled in CAP that is used in the calculation of the offset applied to recoverable CAP costs. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would arguably have occurred if not for CAP. The Company proposes to set the CAP enrollee threshold equal to the number of CAP participants as of September 30, 2026, to provide an enrollee figure that reflects the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

IV. TARIFF CHANGES

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement number, Notice language, Issue and Effective dates, and page numbers as necessary per this case. Apart from the proposed rate schedule changes, a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 63 to UGI Gas Tariff No. 7 and Proposed Supplement No. 63 to UGI Gas Tariff No. 7S. More significant proposed changes to the tariffs include:

- Rule 8.4, Billing and Payment, has clarifying language added to explain that Budget Billing will be reviewed and adjusted on a quarterly basis .
- Section 8.14 was added to specify the acceptable and Applicable Forms of Payment that customers may remit to the Company for payment of public utility service.
- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- Rider C, Weather Normalization Adjustment, applicability has been updated to continue as a pilot ending on October 31, 2032, in place of the existing October 31, 2027, date. In Calculation of Adjustment Amount, subsection (d), the Weather Normalization Adjustment NHDD has been changed to the Delivery Region's 10-year average in place of the existing 15-year average for the given day. Additionally, NHDD has been changed to being updated at every rate case in place of the existing 5 years.
- Rider D – MFC has been set to 2.37% for PGC Residential Customers and 0.47% for Non-Residential PGC Customers, as described above.

- Section 15. Price to Compare ("PTC") has been updated to reflect changes to the MFC.
- Rider F – Universal Service Program has been revised so that the CAP credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2026, in place of the existing September 30, 2025 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b)(1).
- Rule 16 – USP Rider has been updated to reflect that the 9.2% adjustment element contained in the Annual Reconciliation shall apply to the actual number of CAP enrollees as of September 30, 2026, in order to appropriately track related costs for recovery between the Rider and base rates. Additionally, language has been added to allow the USP Rider to apply on a fully negotiated basis for certain Rate XD customers to contribute to Rider USP and otherwise lower USP costs borne by the Company's residential customers.
- Rule 22 - References to outdated Effective Date in heading removed.
- Rate LFD has clarifying language added for Annual Minimum Bill, which allows the Company and customer to reach agreement on a higher Annual Minimum Bill amount. Updated residential and commercial purchase of receivables rates due to the change in the MFC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

UGI Utilities, Inc., Reading, PA

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

Education

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-2021-3023618	UGI Electric Division Base Rate Case
Docket No. R-2021-3030218	UGI Gas Division Base Rate Case
Docket No. R-2022-3037368	UGI Electric Division Base Rate Case
Docket No. R-2024-3052716	UGI Gas Division Base Rate Case

UGI GAS

EXHIBIT SAE-2

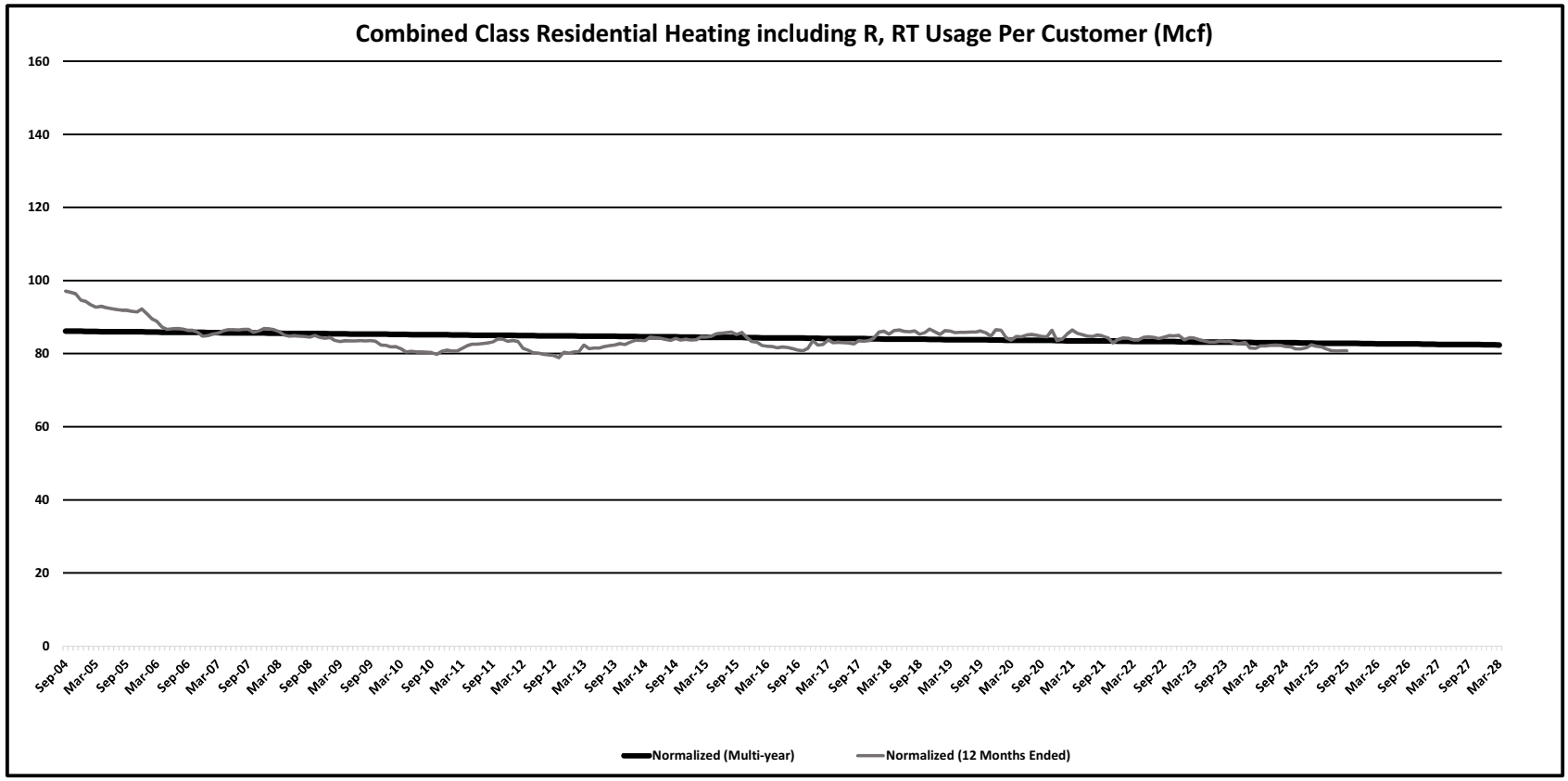
UGI Utilities, Inc. - Gas Division
10 Year Normal Heating Degree Days (2015-2024)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average *
Jan	1,247	1,139	966	1,159	1,153	932	1,030	1,231	829	994	1,069
Feb	1,292	923	722	776	908	799	978	876	753	782	881
Mar	974	586	878	912	834	607	658	684	745	611	749
Apr	420	475	270	579	329	504	397	459	320	349	410
May	93	227	214	67	126	234	214	102	175	101	155
Jun	38	27	38	32	30	21	21	17	34	12	27
Jul	8	4	3	4	2	0	6	1	1	1	0
Aug	13	4	23	3	9	4	3	4	6	15	8
Sep	51	57	94	63	39	101	63	90	79	39	68
Oct	392	326	237	373	275	317	190	386	299	287	309
Nov	525	595	694	780	773	514	728	593	685	569	647
Dec	640	982	1,096	891	928	946	765	970	760	963	895
Totals	5,692	5,345	5,236	5,639	5,406	4,980	5,050	5,411	4,685	4,724	5,218

*Average adjusted for rounding of 10 year calculation and normal representation of Heating Degree Days falling consecutively through normal year

UGI GAS

EXHIBIT SAE-3(a) – (b)


Combined Class Residential Heating including R, RT Usage Per Customer (Mcf)
160
140
120
100
80
60
40
20
0
Sep-04
Mar-05
Sep-05
Mar-06
Sep-06
Mar-07
Sep-07
Mar-08
Sep-08
Mar-09
Sep-09
Mar-10
Sep-10
Mar-11
Sep-11
Mar-12
Sep-12
Mar-13
Sep-13
Mar-14
Sep-14
Mar-15
Sep-15
Mar-16
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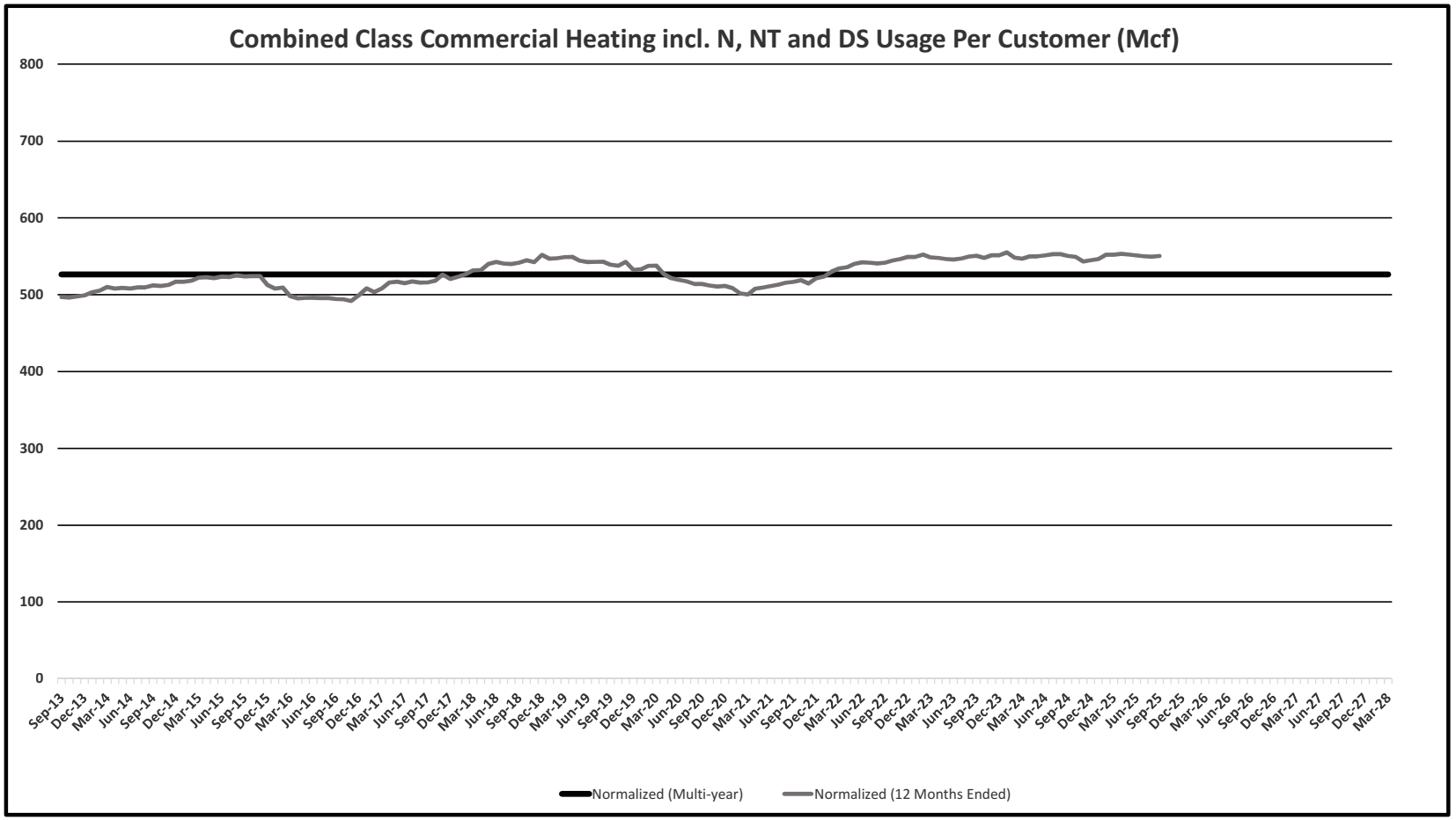
Sep-22
Mar-23
Sep-23
Mar-24
Sep-24
Mar-25
Sep-25
Mar-26
Sep-26
Mar-27
Sep-27
Mar-28
Normalized (Multi-year)
Normalized (12 Months Ended)


Combined Class Commercial Heating incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13
Dec-13
Mar-14
Jun-14
Sep-14
Dec-14
Mar-15
Jun-15
Sep-15
Dec-15
Mar-16
Jun-16
Sep-16
Dec-16
Mar-17
Jun-17
Sep-17
Dec-17
Mar-18
Jun-18
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Dec-18
Mar-19
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Mar-21
Jun-21
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Jun-22
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Dec-25
Mar-26
Jun-26
Sep-26
Dec-26
Mar-27
Jun-27
Sep-27
Dec-27
Mar-28
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (m)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2027 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2027	343,586	1,270,313	795,899	
Adjustment for Customer/Contract Changes	(834)	(11,756)	(5,856)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,308)	(37,090)	(16,560)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		1,938	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		39	39	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		(480)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(257)	(257)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(h)
Adjustment for STAS		116	116	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Rider		(1)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for EEC Conservation Impact	(240)	(3,000)	(1,467)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for GDE		(185)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Adjustment for DSIC		2,615	2,615	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(m)
Fully Projected Future Test Year 2027	339,204	1,220,551	772,828	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other *	[10] Grand Total
1	FPFTY Revenues (Unadjusted)	$ 8,302	$ 744,900	$ 62,495	$ 10,191	$ 204,625	$ 9,584	$ 71,572	$ 36,322	$ 122,323	$ 1,270,313
2	FPFTY PGC Revenues	$ (2,392)	$ (341,620)	$ (5,371)	$ (5,349)	$ (111,591)	$ (5,636)	$ (521)	(836)	(1,096)	(474,414)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,909	$ 403,280	$ 57,123	$ 4,842	$ 93,034	$ 3,947	$ 71,051	$ 35,486	$ 121,226	$ 795,899
4	FPFTY Average Effective Customers (Unadjusted)	19,610	537,257	81,742	3,100	46,767	627	20,567	1,305	985	711,960
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 0.301	$ 0.751	$ 0.699	$ 1.562	$ 1.989	$ 6.296	$ 3.455	$ 27.192	$ 123.073	$ 1.118
6	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	706,232
7	Change in Customers during FPFTY (L6 - L4)	(432)	(3,925)	-	(19)	(1,338)	(14)	-	-	-	(5,728)
8	Annualization of Margin (L5 * L7)	$ (130)	$ (2,946)	$ -	$ (30)	$ (2,662)	$ (88)	$ -	$ -	$ -	$ (5,856)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.423	$ 1.386	$ 0.765	$ 3.287	$ 4.375	$ 15.285	$ 3.480	$ 27.833	$ 124.186	$ 1.784
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (183)	$ (5,442)	$ -	$ (62)	$ (5,854)	$ (214)	$ -	$ -	$ -	$ (11,756)
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (53)	$ (2,496)	$ -	$ (33)	$ (3,193)	$ (126)	$ -	$ -	$ -	$ (5,900)
12	Total FPFTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(7)	(332)	-	(5)	(472)	(19)	-	-	-	(834)

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FPFTY Revenues (Unadjusted)	$ 60,378	$ 39,075	$ 2,294	$ 20,576	$ 122,323
2	FPFTY PGC Revenues	(1,096)	-	-	-	(1,096)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 59,282	$ 39,075	$ 2,294	$ 20,576	$ 121,226
4	FPFTY Average Effective Customers (Unadjusted)	638	54	57	236	985
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 92.918	$ 723.603	$ 40.253	$ 87.186	$ 123.073
6	FPFTY Customers (Fully Adjusted)	638	54	57	236	985
7	Change in Customers during FPFTY (L6 - L4)	-	-	-	-	-
8	Annualization of Margin	$ -	$ -	$ -	$ -	$ -
9	Average Annual Revenue Per Customer (L1 / L4)	$ 94.637	$ 723.603	$ 40.253	$ 87.186	$ 124.186
10	Annualization of Total FPFTY Revenue	$ -	$ -	$ -	$ -	$ -
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	-	-	-	-	-

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Reconciliation Adj. *	[11] Total
1	FPFTY (Unadjusted) Use/Customer ("UPC") - MCF	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40			
2	FPFTY UPC (Fully Adjusted) - MCF	15.90	82.70	76.50	238.90	322.40	655.60	691.80	6,795.40			
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.90)	(3.10)	(16.50)	(30.10)	(675.00)	(9.90)	0.00			
4	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	-	706,232
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	(6)	(1,013)	(253)	(51)	(1,367)	(414)	(204)	-	-	-	(3,308)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ (81)	$ (14,271)	$ (1,815)	$ (565)	$ (15,196)	$ (4,598)	$ (881)	$ -		$ 317	$ (37,090)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 14.0834	$ 14.0834	$ 7.1620	$ 11.1127	$ 11.1127	$ 11.1127	$ 4.3263	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ (36)	$ (6,416)	$ (1,604)	$ (219)	$ (5,880)	$ (1,779)	$ (876)	$ -			$ (16,811)
9	Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	$ 3.3651	$ -		
10	PGC Revenue (L5 * L11)	$ (39)	$ (6,839)	$ -	$ (343)	$ (9,228)	$ (2,792)	$ -	$ -		$ (179)	$ (19,420)
11	PGC Unit Rate	$ 6.7486	$ 6.7486		$ 6.7486	$ 6.7486	$ 6.7486					
12	EE&C Revenue Adjustment (L5 * L13)	$ (1)	$ (197)	$ (49)	$ (1)	$ (35)	$ (11)	$ (5)	$ -			$ (300)
13	EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0449	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ (4)	$ (645)	$ (161)	$ -	$ -	$ -	$ -	$ -	$ -		$ (810)
15	USP Unit Rate	$ 0.6363	$ 0.6363	$ 0.6363	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (1)	$ (175)		$ (2)	$ (52)	$ (16)					$ (245)
17	MFC Unit Rate	$ 0.1728	$ 0.1728		$ 0.0378	$ 0.0378	$ 0.0378					
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
19	DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
20	Total Margin Adjustment (L8 + L16 + L18)	$ (37)	$ (6,591)	$ (1,604)	$ (221)	$ (5,932)	$ (1,795)	$ (876)	$ -		$ 496	$ (16,560)
21	Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3382	$ 4.3382	$ 4.3004	$ -	$ -		

Notes:

* Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for PGC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FPFTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
PGC Revenue Adjustment	$89	$203	$312	$375	$321	$280	$137	$70	$46	$32	$34	$37	$1,938

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for MFC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FPFTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes-Rate R	2,133	4,910	7,406	8,816	7,519	6,622	3,285	1,684	1,101	727	761	834	
Total PGC Volumes-Rate N	801	1,801	2,876	3,568	3,060	2,629	1,249	635	411	342	375	401	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R Adj Rate	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
MFC Rate N Adj Rate	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	
Rate R Revenue Variance	$2	$4	$6	$7	$6	$5	$3	$1	$1	$1	$1	$1	
Rate N Revenue Variance	$0	$0	$0	$1	$1	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$2	$4	$6	$7	$6	$6	$3	$1	$1	$1	$1	$1	$39

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for USP

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original FPFTY Budget USP Calculation	$1,503	$3,460	$5,226	$6,209	$5,291	$4,649	$2,303	$1,182	$779	$516	$538	$591	$32,247
Updated FPFTY Budget USP Calculation	$1,501	$3,455	$5,219	$6,200	$5,284	$4,642	$2,299	$1,180	$778	$515	$537	$590	$32,202
Variance to Original FPFTY Budget Calculation	($2)	($5)	($7)	($9)	($7)	($7)	($3)	($2)	($1)	($1)	($1)	($1)	($46)
Original FPFTY Budget USP Rate	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	
FPFTY USP Rate	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	
USP Rate Variance	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	
Total Rate R Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
Total Rate R excl CAP Volumes	2,327	5,357	8,091	9,613	8,192	7,197	3,565	1,830	1,205	799	833	915	49,925
USP Rate Revenue Variance	($20)	($47)	($70)	($84)	($71)	($63)	($31)	($16)	($10)	($7)	($7)	($8)	($434)
Total Revenue Variance	($22)	($52)	($78)	($92)	($79)	($69)	($34)	($18)	($12)	($8)	($8)	($9)	($480)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for GPC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
GPC Rate FPFTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FPFTY Budget	(171)	(396)	(619)	(762)	(652)	(563)	(271)	(136)	(87)	(68)	(75)	(88)	(3,888)
Revenue Variance	($11)	($26)	($41)	($50)	($43)	($37)	($18)	($9)	($6)	($4)	($5)	($6)	($257)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for STAS

	@ 0% Unadjusted 2027 TOTAL	@.01% Adjusted 2027 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ -	$ 1	$ 1
Residential-Heating	$ -	$ 73	$ 73
Residential-RT	$ -	$ 6	$ 6
Total R/RT	$ -	$ 79	$ 79
Commercial-Non Htg	$ -	$ 1	$ 1
Commercial- Htg	$ -	$ 18	$ 18
Industrial	$ -	$ 0	$ 0
Com/Ind NT	$ -	$ 7	$ 7
Total N/NT	$ -	$ 27	$ 27
Total DS	$ -	$ 4	$ 4
Total LFD	$ -	$ 6	$ 6
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ -	$ 116	$ 116

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for EEC Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget FPFTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
FPFTY R/RT Rate	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	
R/RT Rate Variance	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	
R/RT Rate Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
R/RT Revenue Adjustment	$32	$74	$112	$133	$113	$100	$49	$25	$17	$11	$12	$13	$690
Original Budget FPFTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
FPFTY N/NT Rate	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	
N/NT Rate Variance	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	
N/NT Rate Volumes	1,588	3,234	4,997	6,090	5,240	4,514	2,291	1,257	938	760	815	855	32,580
N/NT Revenue Adjustment	($16)	($33)	($51)	($62)	($53)	($46)	($23)	($13)	($10)	($8)	($8)	($9)	($332)
Original Budget FPFTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
FPFTY DS Rate	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	
DS Rate Variance	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	($21)	($35)	($54)	($70)	($62)	($52)	($30)	($18)	($13)	($11)	($11)	($13)	($389)
Original Budget FPFTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
FPFTY LFD Rate	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	
LFD Rate Variance	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	$2	$3	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2	$30
Total Revenue Adjustment	($2)	$9	$10	$4	$0	$5	($2)	($3)	($4)	($6)	($6)	($7)	($1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 10/01/2025)

Yearly Gas Savings by Rate Class 2026 - 2041 (Cumulative MMBtus)

Rate Class Description	Fiscal Year 2026	2027	2028	2029	2030	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY27 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	187,035	198,006	206,266	214,128	223,043	205,696	1.033	199,124	611,318	**(0.3)**
Nonresidential (N/NT)	35,354	38,780	41,988	46,016	48,158	42,059	1.033	40,716	65,129	**(0.6)**
Total	**222,389**	**236,786**	**248,254**	**260,144**	**271,201**	**247,755**		**239,840**	**676,447**	

Description	[1] Rate R Residential-Htg	[2] Rate RT Residential Htg-RT	[3] Rate N Commercial-Htg	[4] Rate NT Commercial Htg-NT	[5] Rate N Industrial	[6] Rate NT Industrial -NT	[7] Total
FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	82.7	79.4	322.4	674.9	655.6	2,053.9	
FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	82.4	79.1	321.8	674.3	655.0	2,053.3	
Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
End of Year FPFTY Customers	533,332	77,986	45,429	18,631	613	456	676,447
Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(174)	(25)	(28)	(12)	(0)	(0)	(240)
Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (2,447)	$ (182)	$ (316)	$ (50)	$ (4)	$ (1)	$ (3,000)
Total Unit Revenue Adjustment (L6 / L5)	14.0834	7.1620	11.1127	4.3263	11.1127	4.3263	12.5084
Distribution Margin Adjustment (L5 * L9)	$ (1,100)	$ (161)	$ (122)	$ (50)	$ (2)	$ (1)	$ (1,436)
Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	
PGC Revenue (L5 * L11)	$ (1,172)	$ -	$ (192)	$ -	$ (3)	$ -	$ (1,367)
PGC Unit Rate	$ 6.7486		$ 6.7486		$ 6.7486		
EE&C Revenue Adjustment (L5 * L13)	$ (34)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (40)
EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	
USP Revenue Adjustment (L5 * L15)	$ (111)	$ (16)					$ (127)
USP Unit Rate	$ 0.6363	$ 0.6363					
MFC Revenue/Margin Adjustment (L5 * L17)	$ (30)		$ (1)		$ (0)		$ (31)
MFC Unit Rate	$ 0.1728		$ 0.0378		$ 0.0378		
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	
Total Margin Adjustment (L8 + L16 + L18)	$ (1,130)	$ (161)	$ (123)	$ (50)	$ (2)	$ (1)	$ (1,467)
Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3004	$ 4.3382	$ 4.3004	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for GDE Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget FPFTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FPFTY DS Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
DS Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	($2)	($4)	($6)	($8)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($2)	($45)
Original Budget FPFTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FPFTY LFD Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
LFD Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	($11)	($12)	($14)	($15)	($13)	($13)	($11)	($10)	($10)	($10)	($10)	($10)	($139)
Total Revenue Adjustment	($14)	($16)	($20)	($23)	($21)	($19)	($15)	($13)	($11)	($11)	($11)	($11)	($185)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for DSIC

	@ 0% Unadjusted 2027 TOTAL	@0.33% Adjusted 2027 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ -	$ 20	$ 20
Residential-Heating	$ -	$ 1,412	$ 1,412
Residential-RT	$ -	$ 199	$ 199
Total R/RT	$ -	$ 1,631	$ 1,631
Commercial-Non Htg	$ -	$ 15	$ 15
Commercial- Htg	$ -	$ 280	$ 280
Industrial	$ -	$ 7	$ 7
Com/Ind NT	$ -	$ 233	$ 233
Total N/NT	$ -	$ 534	$ 534
Total DS	$ -	$ 118	$ 118
Total LFD	$ -	$ 193	$ 193
Total XD-F	$ -	$ 64	$ 64
Total Interruptible	$ -	$ 73	$ 73
Grand Total	$ -	$ 2,615	$ 2,615

UGI GAS

EXHIBIT SAE-5(a) – (l)

UGI Utilities Inc.- Gas Division
Future Test Year 2026 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2026	343,090	1,256,178	787,256	
Adjustment for Customer/Contract Changes	(981)	(11,976)	(5,772)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,141)	(35,047)	(15,964)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		2,994	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		60	60	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		480	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(235)	(235)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for STAS		205	205	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for EEC Rider		(7)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for GDE		(184)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(k)
Adjustment for DSIC		(338)	(338)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(l)
Future Test Year 2026	338,968	1,210,430	763,512	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other *	[10] Grand Total
1	FTY Revenues (Unadjusted)	$ 8,535	$ 733,593	$ 62,205	$ 10,210	$ 203,505	$ 9,705	$ 71,281	$ 35,926	$ 121,219	$ 1,256,178
2	FTY PGC Revenues	$ (2,462)	$ (336,525)	$ (5,310)	$ (5,371)	$ (111,100)	$ (5,704)	$ (521)	(834)	(1,095)	(468,922)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 6,073	$ 397,068	$ 56,895	$ 4,840	$ 92,405	$ 4,000	$ 70,760	$ 35,092	$ 120,124	$ 787,256
4	FTY Average Effective Customers (Unadjusted)	20,245	531,109	81,742	3,121	46,668	637	20,567	1,304	984	706,377
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 0.300	$ 0.748	$ 0.696	$ 1.551	$ 1.980	$ 6.280	$ 3.440	$ 26.911	$ 122.077	$ 1.114
6	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
7	Change in Customers during FTY (L6 - L4)	(456)	(4,001)	-	(18)	(1,460)	(12)	-	-	-	(5,947)
8	Annualization of Margin (L5 * L7)	$ (137)	$ (2,991)	$ -	$ (28)	$ (2,891)	$ (75)	$ -	$ -	$ 351	$ (5,772)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.422	$ 1.381	$ 0.761	$ 3.272	$ 4.361	$ 15.235	$ 3.466	$ 27.551	$ 123.190	$ 1.778
10	Annualization of Total FTY Revenue (L7 * L9)	$ (192)	$ (5,526)	$ -	$ (59)	$ (6,367)	$ (183)	$ -	$ -	$ 351	$ (11,976)
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (55)	$ (2,535)	$ -	$ (31)	$ (3,476)	$ (107)	$ -	$ -	$ -	$ (6,205)
12	Total FTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(7)	(338)	-	(5)	(515)	(16)	-	-	(99)	(981)

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FTY Revenues (Unadjusted)	$ 60,462	$ 38,765	$ 2,276	$ 19,716	$ 121,219
2	FTY PGC Revenues	(1,095)	-	-	-	(1,095)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 59,367	$ 38,765	$ 2,276	$ 19,716	$ 120,124
4	FTY Average Effective Customers (Unadjusted)	637	55	58	234	984
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 93.197	$ 704.820	$ 39.233	$ 84.258	$ 122.077
6	FTY Customers (Fully Adjusted)	638	54	57	235	984
7	Change in Customers during FTY (L6 - L4)	1	(1)	(1)	1	-
8	Annualization of Margin	$ 37	$ (177)	$ -	$ 491	$ 351
9	Average Annual Revenue Per Customer (L1 / L4)	$ 94.917	$ 704.820	$ 39.233	$ 84.258	$ 123.190
10	Annualization of Total FTY Revenue	$ 37	$ (177)	$ -	$ 491	$ 351
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	21	(366)	-	245	(99)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	FTY (Unadjusted) Use/Customer ("UPC") - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
2	FTY UPC (Fully Adjusted) - MCF	15.90	83.00	76.50	239.80	321.40	719.10	691.80	6,783.40		
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.60)	(3.10)	(15.60)	(31.10)	(608.70)	(9.90)	0.00		
4	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	(6)	(843)	(253)	(48)	(1,406)	(380)	(204)	-	-	(3,141)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ (84)	$ (11,878)	$ (1,815)	$ (538)	$ (15,624)	$ (4,228)	$ (881)	$ -	$ -	$ (35,047)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 14.0834	$ 14.0834	$ 7.1620	$ 11.1127	$ 11.1127	$ 11.1127	$ 4.3263	$ -	$ -	
8	Distribution Margin Adjustment (L5 * L9)	$ (38)	$ (5,340)	$ (1,604)	$ (208)	$ (6,046)	$ (1,636)	$ (876)	$ -	$ -	$ (15,748)
9	Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	$ 3.3651	$ -	
10	PGC Revenue (L5 * L11)	$ (40)	$ (5,692)	$ -	$ (327)	$ (9,488)	$ (2,567)	$ -	$ -	$ -	$ (18,114)
11	PGC Unit Rate	$ 6.7486	$ 6.7486		$ 6.7486	$ 6.7486	$ 6.7486				
12	EE&C Revenue Adjustment (L5 * L13)	$ (1)	$ (164)	$ (49)	$ (1)	$ (36)	$ (10)	$ (5)	$ -	$ -	$ (267)
13	EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0449	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ (4)	$ (537)	$ (161)	$ -	$ -	$ -	$ -	$ -	$ -	$ (702)
15	USP Unit Rate	$ 0.6363	$ 0.6363	$ 0.6363	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (1)	$ (146)		$ (2)	$ (53)	$ (14)				$ (216)
17	MFC Unit Rate	$ 0.1728	$ 0.1728		$ 0.0378	$ 0.0378	$ 0.0378				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
20	Total Margin Adjustment (L8 + L16 + L18)	$ (39)	$ (5,486)	$ (1,604)	$ (210)	$ (6,099)	$ (1,650)	$ (876)	$ -	$ -	$ (15,964)
21	Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3382	$ 4.3382	$ 4.3004	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for PGC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FTY	$6.6061	$6.6061	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.1425	$0.1425	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
PGC Revenue Adjustment	$414	$948	$309	$372	$318	$278	$136	$70	$45	$32	$34	$37	$2,994

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for MFC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FTY	$6.6061	$6.6061	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.1425	$0.1425	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes-Rate R	2,109	4,855	7,323	8,718	7,435	6,548	3,248	1,665	1,089	719	752	824	
Total PGC Volumes-Rate N	799	1,799	2,874	3,566	3,058	2,627	1,248	634	410	341	374	401	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R Adj Rate	$0.0036	$0.0036	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
MFC Rate N Adj Rate	$0.0008	$0.0008	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	
Rate R Revenue Variance	$8	$18	$6	$7	$6	$5	$3	$1	$1	$1	$1	$1	
Rate N Revenue Variance	$1	$1	$0	$1	$1	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$8	$19	$6	$7	$6	$6	$3	$1	$1	$1	$1	$1	$60

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for USP

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original FTY Budget USP Calculation	$1,444	$3,324	$5,020	$6,103	$5,201	$4,569	$2,263	$1,162	$766	$507	$529	$581	$31,469
Updated FTY Budget USP Calculation	$1,442	$3,319	$5,013	$6,094	$5,194	$4,563	$2,260	$1,160	$765	$507	$528	$580	$31,425
Variance to Original FTY Budget Calculation	($2)	($5)	($7)	($9)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($1)	($44)
Original FTY Budget USP Rate	$0.6257	$0.6257	$0.6257	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	
FTY USP Rate	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	
USP Rate Variance	$0.0106	$0.0106	$0.0106	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	
Total Rate R Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
Total Rate R excl CAP Volumes	2,304	5,304	8,012	9,520	8,113	7,127	3,530	1,813	1,194	791	825	907	49,440
USP Rate Revenue Variance	$24	$56	$85	$101	$86	$76	$37	$19	$13	$8	$9	$10	$524
Total Revenue Variance	$22	$52	$78	$92	$79	$69	$34	$18	$12	$8	$8	$9	$480

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GPC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
GPC Rate FTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FTY Budget	(156)	(361)	(568)	(700)	(599)	(517)	(248)	(125)	(80)	(62)	(69)	(81)	(3,565)
Revenue Variance	($10)	($24)	($37)	($46)	($40)	($34)	($16)	($8)	($5)	($4)	($5)	($5)	($235)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for STAS

	Unadjusted 2026 TOTAL	@ 0.01% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (1)	$ 1	$ 2
Residential-Heating	$ (51)	$ 73	$ 124
Residential-RT	$ (5)	$ 6	$ 11
Total R/RT	$ (56)	$ 80	$ 136
Commercial-Non Htg	$ (1)	$ 1	$ 2
Commercial- Htg	$ (13)	$ 20	$ 33
Industrial	$ (0)	$ 1	$ 1
Com/Ind NT	$ (5)	$ 7	$ 13
Total N/NT	$ (20)	$ 29	$ 49
Total DS	$ (3)	$ 4	$ 7
Total LFD	$ (7)	$ 6	$ 13
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (86)	$ 120	$ 205

UGI Utilities Inc.- Gas Division
Future Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EEC Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
FTY R/RT Rate	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	
R/RT Rate Variance	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	
R/RT Rate Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
R/RT Revenue Adjustment	$32	$73	$111	$132	$112	$99	$49	$25	$17	$11	$11	$13	$684
Original Budget FTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
FTY N/NT Rate	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	
N/NT Rate Variance	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	
N/NT Rate Volumes	1,586	3,231	4,995	6,088	5,239	4,512	2,290	1,256	938	759	815	855	32,563
N/NT Revenue Adjustment	($16)	($33)	($51)	($62)	($53)	($46)	($23)	($13)	($10)	($8)	($8)	($9)	($332)
Original Budget FTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
FTY DS Rate	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	
DS Rate Variance	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	($21)	($35)	($54)	($69)	($62)	($52)	($30)	($18)	($13)	($11)	($11)	($13)	($388)
Original Budget FTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
FTY LFD Rate	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	
LFD Rate Variance	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	$2	$3	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2	$30
Total Revenue Adjustment	($2)	$8	$9	$3	($1)	$4	($2)	($4)	($4)	($6)	($6)	($7)	($7)

UGI Utilities Inc.- Gas Division
Future Test Year Period- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GDE Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FTY DS Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
DS Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	($2)	($4)	($6)	($8)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($2)	($45)
Original Budget FTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FTY LFD Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
LFD Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	($11)	($12)	($14)	($15)	($13)	($13)	($11)	($10)	($10)	($10)	($10)	($10)	($139)
Total Revenue Adjustment	($13)	($16)	($20)	($23)	($21)	($19)	($15)	($13)	($11)	($11)	($11)	($11)	($184)

UGI Utilities Inc.- Gas Division
Future Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for DSIC

	Unadjusted 2026 TOTAL	@0.33% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$23	$21	($3)
Residential-Heating	$1,601	$1,422	($179)
Residential-RT	$230	$205	($26)
Total R/RT	$1,855	$1,647	($208)
Commercial-Non Htg	$18	$16	($2)
Commercial- Htg	$344	$306	($39)
Industrial	$15	$13	($2)
Com/Ind NT	$264	$234	($30)
Total N/NT	$641	$569	($72)
Total DS	$133	$118	($15)
Total LFD	$223	$198	($25)
Total XD-F	$84	$74	($9)
Total Interruptible	$79	$70	($9)
Grand Total	$3,015	$2,677	($338)

UGI GAS

EXHIBIT SAE-6(a) – (k)

UGI Utilities Inc.- Gas Division
Historic Test Year 2025 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2025	321,629	1,137,255	718,427	
Adjustment for Customer/Contract Changes	(1,938)	(10,270)	(5,921)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(656)	(4,503)	(1,093)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for WNA		(16,327)	(16,327)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for PGC		51,422	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for MFC		907	907	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for USP		7,370	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for GPC		(86)	(86)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for Excess Take		(2,199)	(2,199)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for STAS		43	43	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for EEC Rider		16	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(k)
Historic Test Year 2025	319,035	1,163,630	693,752	

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other *	[10] Grand Total
1	HTY Revenues net of WNA (Unadjusted)	$ 8,165	$ 619,588	$ 53,943	$ 8,618	$ 170,650	$ 7,954	$ 65,540	$ 50,460	$ 136,011	$ 1,120,928
2	HTY PGC Revenues	$ (2,233)	$ (279,839)	$ (4,739)	$ (4,442)	$ (91,044)	$ (4,543)	$ (505)	(16,078)	(15,406)	(418,829)
3	HTY Revenues net of PGC and WNA - Margin (Unadjusted)	$ 5,932	$ 339,749	$ 49,204	$ 4,175	$ 79,606	$ 3,411	$ 65,035	$ 34,382	$ 120,605	$ 702,099
4	HTY Average Effective Customers (Unadjusted)	21,010	525,925	81,167	3,136	45,320	676	20,780	1,301	978	700,293
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 0.282	$ 0.646	$ 0.606	$ 1.331	$ 1.757	$ 5.046	$ 3.130	$ 26.427	$ 123.318	$ 1.003
6	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
7	Change in Customers during HTY (L6 - L4)	(533)	(6,638)	1,182	(31)	(342)	(3)	(160)	(6)	(3)	(6,534)
8	Annualization of Margin (L5 * L7)	$ (150)	$ (4,288)	$ 717	$ (41)	$ (601)	$ (15)	$ (501)	$ (159)	$ (882)	$ (5,921)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.389	$ 1.178	$ 0.665	$ 2.748	$ 3.765	$ 11.767	$ 3.154	$ 38.786	$ 139.071	$ 1.601
10	Annualization of Total HTY Revenue (L7 * L9)	$ (207)	$ (7,820)	$ 786	$ (85)	$ (1,288)	$ (35)	$ (505)	$ (233)	$ (882)	$ (10,270)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (57)	$ (3,532)	$ 69	$ (44)	$ (687)	$ (20)	$ (4)	$ (74)	$ -	$ (4,349)
12	Total HTY UPC (Unadjusted) - MCF	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(8)	(539)	91	(7)	(118)	(3)	(111)	(42)	(1,200)	(1,938)

Notes:
* Column [9] further detailed on UGI Gas Exhibit SAE-6(b)(1)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	HTY Revenues (Unadjusted)	$ 67,832	$ 39,433	$ 2,984	$ 25,762	$ 136,011
2	HTY PGC Revenues	(11,173)	(267)	(23)	(3,943)	(15,406)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 56,659	$ 39,167	$ 2,961	$ 21,819	$ 120,605
4	HTY Average Effective Customers (Unadjusted)	626	56	58	238	978
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 90.510	$ 699.407	$ 51.051	$ 91.675	$ 123.318
6	HTY Customers (Fully Adjusted)	632	56	58	229	975
7	Change in Customers during HTY (L6 - L4)	6	-	-	(9)	(3)
8	Annualization of Margin	$ 322	$ -	$ -	$ (1,204)	$ (882)
9	Average Annual Revenue Per Customer (L1 / L4)	$ 108.358	$ 704.168	$ 51.441	$ 108.243	$ 139.071
10	Annualization of Total HTY Revenue	$ 322	$ -	$ -	$ (1,204)	$ (882)
11	Annualization of HTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for HTY Sales - MMCF	129	-	-	(1,329)	(1,200)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
2	HTY UPC (Fully Adjusted) - MCF	15.90	83.20	76.60	231.00	307.60	1,184.80	691.10	7,065.70		
3	Change in UPC - MCF (L2 - L1)	0.00	2.00	(0.20)	(3.60)	(37.40)	33.60	(2.60)	36.00		
4	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	-	1,039	(16)	(11)	(1,682)	23	(54)	47	-	(656)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ -	$ 13,549	$ (103)	$ (120)	$ (18,006)	$ 242	$ (218)	$ 154		$ (4,503)
7	Total Unit Revenue Adjustment (L6 / L5)	$ -	$ 13.0456	$ 6.2820	$ 10.7042	$ 10.7042	$ 10.7042	$ 4.0676	$ 3.3074	$ -	$ 6.8675
8	Distribution Margin Adjustment (L5 * L9)	$ -	$ 5,376	$ (85)	$ (43)	$ (6,456)	$ 87	$ (206)	$ 143		$ (1,184)
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.0611	$ -	
10	PGC Revenue (L5 * L11)	$ -	$ 6,861	$	(74)	$ (11,113)	$ 149				$ (4,176)
11	PGC Unit Rate	$ 6.6061	$ 6.6061	$	6.6061	$ 6.6061	$ 6.6061				
12	EE&C Revenue Adjustment (L5 * L13)	$ -	$ 188	$ (3)	$ (0)	$ (61)	$ 1	$ (2)	$ 4		$ 127
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ -	$ 650	$ (10)	$ -	$ -	$ -	$ -	$ -	$ -	$ 640
15	USP Unit Rate	$ 0.6257	$ 0.6257	$ 0.6257							
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ -	$ 156	$	(0)	$ (49)	$ 1				$ 107
17	MFC Unit Rate	$ 0.1500	$ 0.1500	$	0.0291	$ 0.0291	$ 0.0291				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ 318	$ (5)	$ (2)	$ (328)	$ 4	$ (10)	$ 7		$ (16)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Calculated Total Margin Adjustment (L8 + L16 + L18)	$ -	$ 5,850	$ (90)	$ (45)	$ (6,833)	$ 92	$ (216)	$ 150		$ (1,093)
21	Total Unit Margin Adjustment (L20 / L5)	$ -	$ 5.6330	$ 5.4755	$ 4.0620	$ 4.0620	$ 4.0620	$ 4.0315	$ 3.2186	$ -	$ 1.6664

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for WNA Revenues

			WNA Revenue/Margin
Rate R	Residential-Non Htg	$	(55)
Rate R	Residential-Htg	$	(10,180)
Rate RT	RT	$	(1,407)
Rate N	Commercial-Non Htg	$	(75)
Rate N	Commercial-Htg	$	(2,485)
Rate N	Industrial	$	(116)
Rate NT	NT Total	$	(2,010)
	Total	$	(16,327)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for PGC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual PGC Rate HTY	$4.5259	$4.5259	$5.6281	$5.6281	$5.6281	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
September HTY PGC Rate	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
PGC Rate Variance	$2.0802	$2.0802	$0.9780	$0.9780	$0.9780	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	2,556	5,444	10,628	13,898	11,035	6,706	4,082	1,875	1,069	982	1,079	947	60,302
PGC Revenue Adjustment	$5,318	$11,325	$10,394	$13,593	$10,792	$0	$0	$0	$0	$0	$0	$0	$51,422
Check	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for MFC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual PGC Rate HTY	$4.5259	$4.5259	$5.6281	$5.6281	$5.6281	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
September HTY PGC Rate	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
PGC Rate Variance	$2.0802	$2.0802	$0.9780	$0.9780	$0.9780	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes-Rate R	1,916	3,983	7,697	9,968	7,832	4,770	2,913	1,294	730	656	753	620	
Total PGC Volumes-Rate N	641	1,461	2,931	3,931	3,203	1,936	1,169	580	339	326	326	328	
Total PGC Volumes	2,556	5,444	10,628	13,898	11,035	6,706	4,082	1,875	1,069	982	1,079	947	60,302
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0472	$0.0472	$0.0222	$0.0222	$0.0222	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	$0.0092	$0.0092	$0.0043	$0.0043	$0.0043	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Rate R Revenue Variance	$90	$188	$171	$221	$174	$0	$0	$0	$0	$0	$0	$0	
Rate N Revenue Variance	$6	$13	$13	$17	$14	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$96	$201	$183	$238	$188	$0	$0	$0	$0	$0	$0	$0	$907

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for USP

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual HTY USP Rate	$0.4693	$0.4693	$0.5770	$0.5770	$0.5770	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	
September HTY USP Rate	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	
USP Rate Variance	$0.1564	$0.1564	$0.0487	$0.0487	$0.0487	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes	2,184	4,545	8,802	11,414	8,967	5,458	3,327	1,479	843	761	865	718	49,362
Total Rate R excl CAP Volumes	2,084	4,338	8,403	10,897	8,561	5,210	3,176	1,411	805	727	826	686	47,123
USP Rate Revenue Variance	$326	$678	$1,314	$1,704	$1,339	$815	$497	$221	$126	$114	$129	$107	$7,370
Total Revenue Variance	$326	$678	$1,314	$1,704	$1,339	$815	$497	$221	$126	$114	$129	$107	$7,370

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for GPC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
GPC Rate HTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to HTY	(76)	(106)	(143)	(159)	(144)	(139)	(119)	(78)	(109)	(72)	(72)	(90)	(1,308)
Revenue Variance	($5)	($7)	($9)	($10)	($10)	($9)	($8)	($5)	($7)	($5)	($5)	($6)	($86)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(366)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(2,199)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for STAS

		Unadjusted 2025 TOTAL	@-0.12% Adjusted 2025 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$	(10)	$ (10)	$ 0
Residential-Heating	$	(797)	$ (770)	$ 27
Residential-RT	$	(70)	$ (68)	$ 2
Total R/RT	$	(877)	$ (848)	$ 29
Commercial-Non Htg	$	(11)	$ (11)	$ 0
Commercial- Htg	$	(220)	$ (212)	$ 8
Industrial	$	(10)	$ (10)	$ 0
Com/Ind NT	$	(86)	$ (83)	$ 3
Total N/NT	$	(327)	$ (315)	$ 12
Total DS	$	(63)	$ (62)	$ 1
Total LFD	$	(84)	$ (83)	$ 1
Total XD-F	$	-	$ -	$ -
Total Interruptible	$	-	$ -	$ -
Grand Total	$	(1,351)	$ (1,308)	$ 43

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for EEC Rider

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget HTY R/RT Rate	$0.2001	$0.2001	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
HTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,184	4,545	8,802	11,414	8,967	5,458	3,327	1,479	843	761	865	718	49,362
R/RT Revenue Adjustment	($42)	($88)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($130)
Original Budget FTY N/NT Rate	$0.0277	$0.0277	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
HTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,317	2,731	5,244	6,917	5,568	3,408	2,231	1,139	813	745	752	742	31,608
N/NT Revenue Adjustment	$11	$23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34
Original Budget FTY DS Rate	$0.0978	$0.0978	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
HTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	543	836	1,385	1,722	1,385	966	678	418	300	286	309	321	9,149
DS Revenue Adjustment	($5)	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)
Original Budget FTY LFD Rate	$0.0049	$0.0049	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
HTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	2,078	2,123	2,659	3,098	2,472	2,329	2,011	1,720	1,553	1,513	1,578	1,621	24,754
LFD Revenue Adjustment	$62	$63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$125
Total Revenue Adjustment	$26	($9)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16

UGI GAS

EXHIBIT SAE-7(a) – (c)

Detail for Usage per Customer for FPFTY by Class as shown on UGI Gas Exhibit SAE-4(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.0	22,934	366,944
Rate R	15.9	19,178	305,721
Rate RT	16.3	3,756	61,223

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	82.3	611,318	50,311,471
Rate R	82.7	533,332	44,119,383
Rate RT	79.4	77,986	6,192,088
Rate RT Total	76.5	81,742	6,253,311

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	363.6	4,584	1,666,742
Rate N	238.9	3,081	736,180
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	526.2	65,162	34,288,244
Rate N	322.4	45,429	14,644,522
Rate NT	674.9	18,631	12,574,062
Rate DS	6,415.3	1,102	7,069,661
Rate Commercial NT Total	661.0	20,111	13,292,454

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,341.6	1,249	2,924,658
Rate N	655.6	613	401,902
Rate NT	2,053.9	456	936,578
Rate DS	8,812.1	180	1,586,178
Rate NT Total	691.8	20,567	14,229,032
Rate DS Total	6,795.4	1,305	8,868,009

Detail for Usage per Customer for FTY by Class as shown on UGI Gas Exhibit SAE-5(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.0	23,545	376,720
Rate R	15.9	19,789	315,497
Rate RT	16.3	3,756	61,223

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	82.5	605,094	49,920,255
Rate R	83.0	527,108	43,728,167
Rate RT	79.4	77,986	6,192,088
Rate RT Total	76.5	81,742	6,253,311

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	363.6	4,606	1,674,742
Rate N	239.8	3,103	744,179
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	526.2	64,941	34,171,954
Rate N	321.4	45,208	14,528,893
Rate NT	674.9	18,631	12,574,062
Rate DS	6,414.7	1,102	7,068,999
Rate Commercial NT Total	661.0	20,111	13,292,454

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,341.6	1,260	2,950,416
Rate N	719.1	625	449,431
Rate NT	2,053.9	456	936,578
Rate DS	8,739.7	179	1,564,406
Rate NT Total	691.8	20,567	14,229,032
Rate DS Total	6,783.4	1,304	8,845,576

Detail for Usage per Customer for HTY by Class as shown on UGI Gas Exhibit SAE-6(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.0	24,144	386,304
Rate R	15.9	20,447	326,043
Rate RT	16.3	3,697	60,261

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	82.7	597,939	49,449,555
Rate R	83.2	519,287	43,204,587
Rate RT	79.4	78,652	6,244,969
Rate RT Total	76.6	82,349	6,305,230

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	363.6	4,603	1,673,651
Rate N	231.0	3,094	714,839
Rate NT	485.4	1,486	721,304
Rate DS	10,326.4	23	237,507

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	526.2	64,781	34,087,762
Rate N	307.6	44,978	13,835,770
Rate NT	674.9	18,687	12,611,856
Rate DS	6,846.0	1,116	7,640,136
Rate Commercial NT Total	660.9	20,173	13,333,161

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,341.6	1,276	2,987,882
Rate N	1,184.8	673	797,359
Rate NT	2,053.9	447	918,093
Rate DS	8,156.6	156	1,272,430
Rate NT Total	691.1	20,620	14,251,254
Rate DS Total	7,065.7	1,295	9,150,073

UGI GAS

EXHIBIT SAE-8

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 0.1690

2/ Weekend Load Reduction Factor (%) 13.4%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.134)) * WE
WD = 1.15 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.134)) + 2] * WE] / 7
7.75 * WE / 7
Step 2 WE = 0.90 * AVERAGE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.134)) - 2) * WE] - (3 * AVERAGE)
3.75 * WE - (3 * AVERAGE)
0.38 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.38 x Average) / (7 x AVERAGE)] x 0.169
0.05 x 0.169
0.0085

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0085 x 20
0.1700

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages

2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Oct 2024 through Sep 2025

3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days

4/ Assumes levelized deliveries on all days

UGI GAS

EXHIBIT SAE-9

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.4940	(A)
2/	Anticipated Average Monthly Imbalance %	0.9401%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.7%	(C)
LFD	58.6%	(C)
XD Firm	57.5%	(C)
Transportation System Average	51.4%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0198	(E)
LFD	0.0113	(E)
XD Firm	0.0116	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Oct 2024 through Sep 2025
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

UGI GAS

EXHIBIT SAE-10

UGI Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

		Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$ 22,053,717		
Allocator 1/		93.47%	6.24%
Uncollectible Revenue Requirement		$ 20,612,599	$ 1,376,805
Total Proposed Revenue		$ 869,313,264	$ 292,438,718
MFC % 2/		2.37%	0.47%

1/ The allocator is based on a 3-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS STATEMENT NO. 11

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:
Cost of Service
Revenue Allocation
Rate Design
Weather Normalization Adjustment

Dated: January 28, 2026

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I. WITNESS IDENTIFICATION AND BACKGROUND

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company") Gas Base Rate Case.

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Gas's fully allocated cost of service study ("ACOSS"), which is found in UGI Gas Exhibit D. The ACOSS determines the embedded costs of serving UGI Gas's distribution customers associated with the Pennsylvania Public Utility Commission ("Commission") jurisdiction. I also support the apportionment, or allocation, of the class revenue increase, and the Company's rate design proposal. Finally, I am supporting the Company's Weather Normalization Adjustment ("WNA") proposal.

Q. Please describe your educational background and professional experience.

A. UGI Gas Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

Q. Please summarize the content of your testimony.

A. My testimony consists of this introduction section (I) and the following six additional sections: (II) Purpose and Principles of Cost Allocation, (III) UGI Gas's Allocated Cost of Service Study, (IV) Principles of Sound Rate Design, (V) UGI Gas's Class Revenues, (VI) UGI Gas's Rate Design, and (VII) WNA Mechanism.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Gas Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. Also, I am sponsoring portions of Book I and Book II, Section 53.53 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation. Related to the WNA proposal, I'm sponsoring the following exhibits:

- UGI Gas Exhibit JDT-2, Normal Heating Degree Days Report;
- UGI Gas Exhibit JDT-3, WNA Data Report; and
- UGI Gas Exhibit JDT-4, WNA Mechanism Policy Factors.

II. ALLOCATED COST OF SERVICE STUDY OVERVIEW

Q. What is the general purpose and use of an ACOSS in regulatory proceedings?

A. The purpose of an ACOSS is to allocate the gas distribution utility's overall fully projected future test year ("FPFTY") costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers cause the utility to incur the costs to provide

service. The requirement to develop the ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and commodity developed in the ACOSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Is the preparation of an ACOSS an exact science?

A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers, with such return on being reflective of a fair rate of return. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. Is there a guiding principle that supports the appropriate allocation of costs?

A. Yes, a fundamental foundational principle, cost causation, should be followed to produce accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs, so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. An important element in the selection and development of a reasonable ACOSS methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. To accomplish this, I reviewed UGI Gas's expense and plant accounts, operational data, usage information, and conducted interviews with UGI Gas employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for the utility's plant and expense elements.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the basis to conduct an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Gas's primary functional cost categories associated with natural gas distribution services include gas supply, storage, transmission, distribution, and customer. Indirect costs that support

these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. Please describe the types of costs contained in the customer, demand, and commodity costs categories.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to UGI Gas's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by UGI Gas for its customers.

Q. Please describe the cost allocation process.

A. The final step is to allocate each functionalized and classified cost element to the individual rate class. Costs are typically allocated on customer, demand, commodity, or revenue allocation factors. From a cost-of-service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore,

differences in the cost of meters are reflected by using a different average meter cost for each class of service. Notably, UGI Gas has performed direct assignment analysis of its most competitive negotiated rate customers who receive service under Rate XD, and those direct assignment results are reflected in the ACOSS presented in UGI Gas Exhibit D.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors that can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting UGI Gas's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study is conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory

environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

III. UGI GAS'S ALLOCATED COST OF SERVICE STUDY

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Gas has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model on a proprietary basis for its consulting engagements, and it has been used in multiple

jurisdictions. This is the same model I sponsored in the Company's last base rate case at Docket No. R-2024-3052716.

Q. Please describe the process of performing UGI Gas's ACOSS presented in this filing.

A. The detailed process description of UGI Gas's ACOSS analysis is presented in Exhibit D, providing a full scope of the process including the development of allocation factors that support various cost of service studies presented in this proceeding as discussed below.

Q. Please discuss the content of Exhibit D.

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(1) and, in particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1), Exhibit A.

Exhibit D consists of three sections detailing the process of developing the ACOSS. Section I – Introduction includes an introduction, the general purpose and process of the ACOSS, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. Section II – UGI Gas's Cost of Service Procedures presents the ACOSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section II.3) describes all internal and external allocation factors and the allocation processes used in the ACOSS. The last section, Section III – UGI Gas's Cost of Service Results depicts the results of the ACOSS, including revenue requirement apportionment, comparison of

cost of service with revenues under current and proposed rates, and development of rate of return by customer class under current and proposed rates.

Q. Please describe the content and schedules included in Exhibit D.

A. Exhibit D contains a narrative description of the ACOSS procedures, provides details on the allocation factors, and contains the following Schedules:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors

Q. What was the source of the cost data analyzed in UGI Gas's ACOSS?

All cost-of-service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and schedules contained in this general rate case filing for the FPFTY ending September 30, 2027. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are UGI Gas's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Gas's ACOSS, I included six rate classes:

- Rate R - General Service – Residential & Residential Transportation
- Rate N - General Service – Non-Residential & Non-Residential Transportation
- Rate DS - Delivery Service
- Rate LFD - Large Firm Delivery Service
- Rate XD Firm - Extended Large Firm Delivery Service
- Rate IS - Interruptible Service

Q. Do you propose any modification to the current customer classes?

A. No. I am not proposing any modifications to the existing customer classes. The current class structure aligns with the Company's approved tariff schedules and is consistent with the configuration adopted in the Company's most recent general rate case, Docket No. R-2024-3052716.

Q. How did you classify and allocate the cost of distribution mains?

A. I classified distribution mains as 100% demand related and allocated their costs in two steps. First, a portion of the costs was directly assigned to Rate XD Firm based on an analysis provided by the Company. Second, I allocated the remaining balance using the Average and Excess ("A&E") method.

Q. Please describe the methodology used for the costs directly assigned to the XD customers.

A. For each customer, a distribution system analysis is performed to determine which assets (including footage, diameter, material type, and vintage year) of the distribution system are utilized to serve each Rate XD customer. Using the Company's plant records, the costs and footage for these assets are summarized based on the footage assigned to the customer as a percentage of the total footage for that asset. A portion of this cost is allocated to each Rate XD customer based on the customer's throughput on that asset as a percent of the asset total. The calculated costs for all assets assigned to each Rate XD customer are summed to determine that customer's directly allocated costs. These customer-level costs are then summed across all Rate XD customers to develop the direct assignment for the Rate XD class.

Q. Please describe the A&E method.

A. The A&E method allocates costs based on a combination of average usage and peak usage levels. This method is used to allocate costs on both the consistent usage (average demand), and the additional capacity needed during peak times (excess demand). The average demand is determined by the average daily throughput volumes per customer class. The excess demand represents the additional capacity needed to meet the peak demand or maximum usage levels for each customer class. These two factors are weighted based on the system load factor, which is the ratio of average demand to peak demand for

the entire system. This factor determines the proportion of costs attributed to average daily usage versus peak capacity requirements.

Q. Can you explain the system load factor and its significance in this method?

A. The system load factor is calculated as follows:

Load Factor = Average Daily Throughput ÷ Peak Day Demand

It indicates the efficiency of the system's utilization. A higher load factor suggests that demand is relatively stable, reducing the need for excess capacity. This metric helps balance the cost allocation between average usage and peak demand. UGI Gas's firm service load factor for the FPFTY is 40.53%, which is the system load factor excluding interruptible load. Therefore, the allocation assigns 40.53% of the costs to average daily usage and 59.47% to peak demand.

Q. Why is the interruptible load excluded from the load factor calculations?

A. Interruptible load is excluded from the load factor calculations because it does not contribute to the system's peak day demand, which is a critical driver of infrastructure. In addition, interruptible customers are not assigned any excess load. Interruptible customers agree to reduce or halt their gas usage during periods of high demand, meaning they do not place the same capacity requirements on the distribution system as firm customers. Including interruptible load would misrepresent the true cost drivers and unfairly allocate costs to customers who do not rely on guaranteed peak capacity.

Q. Has the A&E method been approved by the Commission?

A. Yes. The A&E method was approved by the Commission in PECO Energy Company's rate case at Docket No. R-2020-3018929.

Q. Did you consider other classification or allocation methods?

A. Yes. I considered the customer/demand classification method and the Peak and Average ("P&A") allocation method. However, the Commission has not traditionally recognized the customer component of gas mains, which means the customer/demand classification method is not consistent with past Commission orders.[1] The P&A allocation method has also been evaluated for use in past Pennsylvania rate cases and applies a fixed 50/50 weighting instead of relying on the system load factor.

Q. How do the allocation results differ between the A&E method and the P&A method for UGI Gas in this case?

A. The allocation results for each method are presented below in Table 1. The A&E method allocates a higher percentage of costs to Rate R (46.8% vs. 44.7%) and Rate N (31.6% vs. 28.9%), reflecting its reliance on the system load factor. On the other hand, the P&A method allocates a higher percentage of costs to Rate LFD (15.4% vs. 11.7%) and Interruptible (4.3% vs. 3.5%), due to its 50/50 weighting of average demand within the peak portion. These differences illustrate how the P&A method allocates more costs to

[1] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order entered February 19, 2021), p. 217.

higher-load factor customers than the A&E method, despite those customers having more efficient use of the system.

Table 1 – Comparison of Mains Allocators of the Company's ACOSS

	Rate R	Rate N	Rate DS	Rate LFD	Interruptible
A&E	46.8%	31.6%	6.4%	11.7%	3.5%
P&A	44.7%	28.9%	6.7%	15.4%	4.3%

Q. Does UGI Gas's ACOSS include gas commodity costs?

A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a neutral impact on the study's results, resulting in a net-zero effect.

Q. Please summarize the results of the Company's ACOSS.

A. Table 2 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Gas Exhibit D. The ACOSS shows an overall revenue requirement of $1,234.7 million and a resulting deficiency of $99.4 million. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve.

Table 2 - Summary Results of the Company's ACOSS ($000)[2]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Rate R	$ 794,595	$ 895,723	$ (101,128)	12.7%	5.2%	0.89	0.96
Rate N	269,032	292,438	(23,405)	8.7%	6.5%	0.92	0.99
Rate DS	36,024	34,197	1,827	-5.1%	9.3%	1.05	1.14
Rate LFD	58,792	54,870	3,922	-6.7%	9.6%	1.07	1.16
Rate XD Firm	39,155	26,027	13,128	-33.5%	17.0%	1.45	1.56
Rate IS	22,953	16,665	6,288	-27.4%	14.3%	1.37	1.48
Total Base	**1,220,551**	**1,319,920**	**(99,369)**	**8.1%**	**6.5%**	**0.93**	**1.00**
Other Revenues	14,131	14,131	-				
Total Company	**1,234,682**	**1,334,051**	**(99,369)**				

The ACOSS shows that Rate R and Rate N classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. In other words, to set each classes' revenues equal to their cost to serve indicated in the ACOSS, Rate R and Rate N would require an increase in revenues, while all other classes would require a decrease. Additionally, Table 2 provides helpful insights into UGI Gas's class financial metrics, such as the current Rate of Return and corresponding Relative Rate of Return and Current Revenue to Cost Ratio with the corresponding Parity Ratio.

Q. Have you prepared more detailed reports of UGI Gas's ACOSS results?

A. Yes, additional details are included in Exhibit D. Schedule 4 "Account Balances and Allocation Methods" of Exhibit D includes revenue requirement information by FERC account provided by UGI Gas and shows assigned functions, categories, and allocation factors. Schedule 3 "Cost of Service Allocation Study Detail by Account" of Exhibit D

[2] See Exhibit D, Schedule 1, lines 13, 52, 57, 24, 26, and 27.
Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

presents the resulting allocations by customer class of UGI Gas's proposed revenue requirement based on the results of the computations included in the ACOSS.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. The rate design principles below draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3] Each of these principles plays an important role in analyzing the rate design proposals of UGI Gas and provides a roadmap that helps guide utilities and regulators when considering how to achieve utility rates that are fair, efficient, practical, and reasonable. The foundation of rates should include:

- Fairness: Rates should be fair to all customer classes, avoiding undue discrimination.
- Efficiency: Rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use.
- Simplicity: Rates should be simple and understandable for customers.
- Stability/Gradualism: Rates should provide bill stability for customers and revenue stability for the utility.
- Reflective of Costs: Rates should reflect the cost of providing service to different customer classes.

[3] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

- Revenue Sufficiency: Rates should generate enough revenue to cover the utility's costs, including a reasonable return on investment.

In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[4] where the Commonwealth Court indicated that cost of service is the "polestar" of ratemaking but that other factors, including those listed above, can be considered as well.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information are evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

V. UGI GAS'S REVENUE APPORTIONMENT

Q. Please describe the approach used by UGI Gas to allocate its proposed $99.4 million revenue increase among its customer rate classes.

A. UGI Gas's proposed allocation of the revenue increase is informed by the results of the ACOSS and reflects a deliberate effort to move all rate classes closer to the overall system

[4] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

rate of return, thereby reducing the subsidies that currently exist between classes. This approach is consistent with long-standing regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement in that case.

The benchmark option evaluated under UGI Gas's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. This is shown above in Table 2 where the changes in each classes' revenues would be set to their deficiency or surplus. It was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue, given the large increase required to move some classes to parity. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. To accomplish this, the Company first reflected the slight rate decreases for competitively negotiated classes XD and IS in the mechanics of the calculations, resulting from incorporating the current Distribution System Improvement Charge ("DSIC") rider into base rates. Second, Rate N was assigned an increase to move them to parity, equivalent to 1.18 times the system increase. Finally, Rates DS and LFD were assigned increases that correct approximately two-thirds of the class's over-earning relative to the system-average rate of return. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the reduction in the subsidies occurring between classes. In addition, the Company's proposal results in keeping the residential average monthly bill increase under

$10, and with these considerations, the Company is proposing the revenue changes shown in Table 3 below.

Table 3 – Proposed Class Revenue Apportionment
Base Distribution Margin ($000)[5]

Customer Classes	Current Revenues	Proposed Revenues	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio
Rate R	$ 794,595	$ 869,272	$ 74,677	9.4%	7.4%	0.97
Rate N	269,032	$ 292,418	23,386	8.7%	8.2%	1.00
Rate DS	36,024	$ 36,732	708	2.0%	9.4%	1.07
Rate LFD	58,792	$ 59,528	736	1.3%	9.4%	1.08
Rate XD Firm	39,155	$ 39,090	(64)	-0.2%	16.4%	1.44
Rate IS	22,953	22,879	(73)	-0.3%	13.7%	1.37
Total Base	**$ 1,220,551**	**$ 1,319,920**	**$ 99,369**	**8.1%**	**8.2%**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes, moving classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement and reduction in class rate subsidies is desirable, as it brings class revenues and rates closer to the indicated cost of service for each rate class.

Table 4 below compares the current and proposed rates of returns and parity ratios. The Company's proposal moves the return for all rate classes closer to the Company's proposed return. Likewise, parity ratios move closer to the desired 1.0 level.

[5] See Exhibit D, Schedule 1, lines 10, 52, 58, 61, 70, and 72.

Table 4 - Comparison of Relative Rate of Return by Rate Class
Base Distribution Margin ($000)[6]

Customer Classes	Current Revenues	Proposed Revenues	Current Return	Proposed Return	Current Parity Ratio	Proposed Parity Ratio
Rate R	$ 794,595	$ 869,272	5.2%	7.4%	0.96	0.97
Rate N	$ 269,032	$ 292,418	6.5%	8.2%	0.99	1.00
Rate DS	$ 36,024	$ 36,732	9.3%	9.4%	1.14	1.07
Rate LFD	$ 58,792	$ 59,528	9.6%	9.4%	1.16	1.08
Rate XD Firm	$ 39,155	$ 39,090	17.0%	16.4%	1.56	1.44
Rate IS	$ 22,953	$ 22,879	14.3%	13.7%	1.48	1.37
Total Base	**$ 1,220,551**	**$ 1,319,920**	**6.5%**	**8.2%**	**1.00**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current subsidies, proposed subsidies, and the reduction in subsidies for all customer classes resulting from the Company's proposed revenue apportionment.

Table 5 - Comparison of Current and Proposed Subsidies ($000)[7]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Rate R	$ (34,867)	$ (26,451)	$ 8,416
Rate N	(23)	(20)	3
Rate DS	4,965	2,535	2,430
Rate LFD	9,160	4,658	4,502
Rate XD Firm	13,654	13,063	590
Rate IS	7,112	6,215	897
Total Company	$ -	$ -	$ -

[6] Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.
[7] See Exhibit D, Schedule 1, lines 35 and 63. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

VI. UGI GAS'S RATE DESIGN

Q. Please summarize the rate design changes UGI Gas has proposed in this rate proceeding.

A. In general, UGI Gas's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide natural gas distribution service to those customers. UGI Gas has proposed the following rate design changes to its current tariff schedules:

- Rate R – Increase in the monthly customer charge from $16.25 to $23.00, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate N – Increase in the monthly customer charge from $36.42 to $39.00, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate DS – Increase in the monthly customer charge from $300 to $353, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate LFD – Increase in the volumetric charge from $1.3831 per Mcf to $1.4173 per Mcf.
- Rate XD Firm – Decrease equivalent to the DSIC rider amount.
- Rate IS – Decrease equivalent to the DSIC rider amount.

Q. Has the Company prepared a detailed comparison of the Company's current and proposed rates and resulting revenues by rate class?

A. Yes. UGI Gas Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, Statement No. 10, presents a detailed comparison of current and proposed revenues for each of UGI Gas's rate classes.

Q. What billing determinants were used to develop the Company's proposed base rates in this proceeding?

A. Consistent with the Settlement Agreement approved by the Commission in Docket Nos. R-2024-3052716 et al., the Company evaluated the use of a ten-year historical period and determined that a ten-year historical average of heating degree days ("HDDs") ending December 31, 2024, is a more appropriate basis for both base-rate billing determinants and WNA calculations. In support of this conclusion, I am sponsoring the Normal Heating Degree Days Report in UGI Gas Exhibit JDT-2, which evaluates long-term weather trends and normalization alternatives and recommends adoption of a ten-year historical average to reflect more recent weather conditions. Specifically, this analysis was undertaken pursuant to the settlement agreement approved by the Commission on September 11, 2025, at Docket Nos. R-2024-3052716, et al. which established the following requirement:

> UGI Gas will include in its filing a report and recommendation on the use of a rolling ten-year historical average period to be used to calculate its normal heating degree day amounts for purposes of the WNA, as well as the use of a ten-year historical average period for purposes of determining projected sales and billing determinants in base rates. (p.12)

As set forth in UGI Gas Exhibit JDT-2, the Company proposes that the 10-year normals be updated in conjunction with each future rate case filing. This would replace the Company's current practice, wherein it used 15 years of weather data updated every five years, with the last update – the one that supported the rates established in Docket R-2024-3052716 – based on data ending on December 31, 2019.

Q. What factors drove the change in billing determinants in this case compared to prior rate cases?

A. Two primary factors contributed to the change in billing determinants in this case. First, as I just described, in the prior proceedings, the Company relied on a fifteen-year historical average ending in 2019. Under the Company's current methodology, it was required to update its normal weather in this proceeding. Updating that methodology alone, by advancing the fifteen-year period to include more recent data, would have replaced approximately one-third of the historical observations with newer years that generally reflect lower heating degree days. As a result, even without a change to a ten-year historical average of HDDs, normalized billing determinants would have declined due to the inclusion of warmer recent weather.

Second, in compliance with the Settlement Agreement, the Company evaluated and ultimately is proposing the use of a ten-year historical average ending December 31, 2024. As demonstrated in Exhibit JDT-2, a ten-year period more closely aligns with observed recent weather patterns and the long-term downward trend in heating degree days, while avoiding the overstatement of heating demand that can occur when older, colder years remain embedded in the normalization period.

Q. How does the ACOSS support the proposed increases to customer charges?

A. Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue

requirement. Table 6 below provides the information related to the current and proposed customer charges for Rates R, N, and DS, compared to the customer-related unit cost per customer per month.

Table 6 - Customer Charge Current, Proposed, and ACOSS Unit Cost Results ($)[8]

Customer Classes	Current Basic Facilities Charge	Proposed Basic Facilities Charge	Customer Related Unit Cost	Demand and Customer Related Unit Cost
Rate R	16.25	23.00	54.03	79.04
Rate N	36.42	39.00	70.69	224.16
Rate DS	300.00	353.00	542.90	2,201.57

As seen in the above table, the proposed increases in customer charges are still under the customer-related unit cost identified in the ACOSS. These include the customer portion of distribution facilities, as well as customer service and billing costs.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed customer charges and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related operations and maintenance ("O&M") expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a Rate R customer charge of $23.00, which is below the $54.03 within Table 6 above, and represents meter reading, customer service, and

[8] See Exhibit D, Schedule 2, lines 118 and 119.

billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $23.00. Similarly, the Company is proposing customer charge increases to Rate N and Rate DS that are still well below the customer related unit cost for these rates.

Q. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A. These proposed customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low-income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric charges, which has the effect of causing some customers to pay too much while others pay too little. The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the

system. These costs, such as the expense of reading meters and billing, occur regardless of whether natural gas is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure the Company's recovery of a greater portion of its fixed costs of providing service. Inasmuch as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily recognize fixed cost charges and are used to these pricing structures in their everyday lives. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well.

Q. Please expand on why an increase in the Rate R customer charge would benefit low-income customers.

A. There is often a common misconception that low-income customers are low-usage customers. This is not a correct characterization of low-income customers on the Company's system who are indeed higher-use customers. According to the Company's historical residential customer billing data[9], the average use for confirmed low-income customers not enrolled in the Customer Assistance Program ("CAP")[10] is 86.7 Mcf/year.

[9] Based on three full years (2022, 2023 and 2024) of residential customer billing data. This dataset included individual monthly usage levels for each customer, along with key identifying attributes that enabled segmentation of the residential class for comparative purposes.

[10] Customers with Confirmed Low-Income indicator as of January 2025. Confirmed Low Income indicator is applied when a customer provides proof of income and is subsequently enrolled in CAP, participated in Low Income Usage Reduction Program ("LIURP"; 200% Federal Poverty Income Guidelines ("FPIG")) or received an Operation Share grant (250% FPIG) or a Low Income Home Energy Assistance Program ("LIHEAP") grant (150% FPIG) within prior 12 months.

This is 14% higher than the average of the Company's residential non-low-income customer use of 76.0 Mcf/year.

Also, all else being equal, higher customer charges necessitate lower variable charges. The collection of costs through fixed or volumetric charges is only the means of collecting the revenue to cover costs for a specific customer class. The amount of total revenue that must be recovered does not change. Higher usage customers pay more when more fixed customer costs are embedded in the volumetric rates. This creates a social equity concern, as customers who can afford to reduce their usage through energy efficiency investments can decrease their bills by making such investments, while those customers who cannot afford to make energy efficiency investments will see increases in their bills. Examples of those who could possibly afford to reduce their usage include higher-income households who can undertake more expensive energy efficiency measures. While some environmental advocates may prefer that households stop using natural gas altogether, families still use gas as an economic energy source for basic human needs such as keeping themselves warm, cooking, and caring for themselves.

Further, recovering fixed costs in volumetric charges places regressive burdens on low-income households who have to make decisions to reduce their gas usage, which impacts their quality of life. Families use gas as an economic energy source for basic human needs such as keeping themselves warm, to cook, and care for themselves. For many households, particularly low-income customers, a substantial portion of natural gas consumption reflects non-discretionary usage necessary to meet basic human needs and

cannot be meaningfully reduced through "just use less" through price signals, absent the ability to invest in more efficient equipment or building improvements.

Lastly, considerations relating to the intersection of income and rate design would be amiss if they did not include discussions relating to UGI Gas's low-income programs. UGI Gas has available a continuum of low-income targeted programs, beyond CAP, including facilitating Low-Income Home Energy Assistance Program ("LIHEAP"), and offering Low-Income Usage Reduction Program ("LIURP") and weatherization assistance, as well as Operation Share to address customers experiencing economic hardship.

Q. Have you conducted an analysis of the difference between the current $16.25 monthly residential customer charge and the proposed $23.00 a month charge on low-income customers?

A. Yes. Table 7 compares the amount a confirmed non-CAP low-income customer with an average usage of 86.7 Mcf/year would pay between the customer charge and the volumetric charge under the Company's proposal (Scenario A) of increasing the monthly customer charge to $23.00, and Scenario B, which keeps the monthly customer charge unchanged at $16.25.

Table 7 – Comparison of Annual Charges for Average CAP Customer[11]

Average LI Customer (non-CAP)	Scenario A	Scenario B	B - A	% change
Customer Charges	$ 276.00	$ 195.00	$ (81.00)	-41.5%
Distribution Charges	592.61	680.78	$ 88.18	13.0%
Total Annual Charges	**$ 868.61**	**$ 875.78**	$ 7.18	0.8%

The comparison shows that while the Company's proposal increases the annual customer charges by $81.00 or 41.5%, the increase is offset by the $88.18 or 13.0% lower distribution charges. In other words, by not changing the current customer charge, customers may face higher overall costs because of the increase in distribution charges. This suggests that any policy or pricing adjustment leading to keeping the customer charge unchanged would shift more costs to the variable distribution component, increasing the financial burden on low-income customers, close to 1%, over a year. As previously stated, a volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the utility's system; and (4) needlessly inflate bills in the winter months. The important policy point in this discussion is that it makes no economic sense to send the wrong economic price signals to all customers in order to supposedly benefit a small subset of low-income

[11] Scenario A uses a monthly customer charge of $23.00 and distribution charges of $6.8383/Mcf, as proposed by the Company. Scenario B uses the current monthly customer charge of $16.25 and distribution charges of $7.8558/Mcf, which would be necessary to recover Rate R's proposed revenue.

customers. It is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP.

VII. WNA MECHANISM

Q. What is the Company's proposal regarding WNA in this proceeding?

A. UGI Gas is requesting the Commission to extend the current WNA pilot mechanism for an additional five (5) years after its current expiration in October 2027. This request follows the settlement agreement approved by the Commission on September 11, 2025, at Docket Nos. R-2024-3052716, et al. which established the following:

> UGI Gas's WNA Pilot will end on October 31, 2027, unless affirmatively extended or otherwise permitted by Commission order. Should UGI Gas request a continuation or modification of the WNA for the period on or after November 1, 2027, it may file a stand-alone Petition or incorporate into a base rate proceeding to be filed no later than January 31, 2026. (p.12)

Q. Has the Commission recently approved similar WNA mechanisms?

A. Yes. For example, in its most recent Final Order in the Columbia Gas of Pennsylvania ("Columbia") case, issued in December 2025, the Commission explicitly approved the continuation of Columbia's WNA mechanism "to allow it a reasonable opportunity to earn up to its Commission-authorized revenue requirement."[12]

[12] Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2024-3067174, Final Order at 301 (Dec. 4, 2025).

Q. Has the Company complied with the WNA stipulations from the settlement agreements in prior rate cases?

A. Yes. As mentioned above, I am sponsoring the Normal Heating Degree Days Report in UGI Gas Exhibit JDT-2, which supports utilizing a 10-year weather history, and was agreed upon in Docket No. R-2024-3052716, et al. In addition, as explained by Company witness Brian J. Meilinger, UGI Gas Statement No. 12, the Company has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716, et al. Lastly, UGI Gas Exhibit JDT-3 provides the WNA data requested by the parties in the settlement agreements in Dockets No. R-2021-3030218 and No. R-2024-3052716.[13]

Q. How does the use of a ten-year historical average for billing determinants relate to the Company's WNA?

A. The use of a ten-year historical average serves a consistent and complementary role in both base-rate development and WNA operation. Base rates are established using billing determinants normalized to the same ten-year weather baseline against which actual weather will later be compared under the WNA. Maintaining this consistency ensures that the WNA functions as intended by adjusting revenues solely for deviations between actual weather and the normalized weather assumptions embedded in rates.

[13] The Company has filed five reports with the Commission since November 30, 2023, containing WNA data from April 2023 through October 2025. These reports are available at https://www.puc.pa.gov/pcdocs/1807398.pdf, https://www.puc.pa.gov/pcdocs/1835933.pdf, https://www.puc.pa.gov/pcdocs/1857431.pdf, https://www.puc.pa.gov/pcdocs/1885030.pdf, and https://www.puc.pa.gov/pcdocs/1904492.pdf

As explained in Exhibit JDT-2, using different weather baselines for rate-setting and WNA calculations could introduce misalignment and unintended over or under recovery. By applying the same ten-year historical average for both purposes, the Company preserves methodological integrity and ensures that customers and the Company are treated fairly when weather conditions differ from normal.

Q. Does the use of a ten-year historical average eliminate the need for a WNA?

A. No. While a ten-year historical average better reflects recent weather conditions, actual heating degree days will continue to vary from year to year in ways that cannot be predicted with certainty. Accordingly, the WNA remains an important mechanism to address year-to-year weather variability by reconciling revenues to the normalized assumptions used to set rates, thereby protecting both customers and the Company from the financial effects of abnormal weather.

Using a ten-year historical average also improves the definition of "normal" weather by placing greater weight on more recent conditions. As a result, deviations between actual weather and normalized assumptions are expected to be smaller, on average, than under a longer historical period that includes older, less representative data. This improved alignment is expected to reduce the magnitude of WNA surcharges or credits over time, while preserving the WNA's role in addressing unavoidable weather variability.

Q. Please describe the Company's proposed WNA.

A. After adopting the modifications to the current WNA pilot pursuant to the Commission-approved settlement at Docket No. R-2024-3052716, UGI Gas's WNA mechanism functions as follows:

i) It adjusts the usage in customer bills based on deviations from normal weather, as measured by Heating Degree Days ("HDDs"), by comparing actual HDDs ("AHDDs") to normal HDDs ("NHDDs") based on a 15-year weather history.

ii) It includes a 3% deadband, meaning no adjustment is made unless the weather deviates by more than ±3% from normal. This prevents minor weather variations from triggering bill changes and ensures that adjustments occur only when there are material deviations.

iii) It applies to Residential (excluding CAP customers) and Small Commercial classes.

iv) It applies during the heating season months of October through April. By excluding non-heating season usage and focusing on the weather-sensitive portion of consumption, the mechanism is carefully targeted and limited in scope. Specifically, the WNA no longer applies in May.

Q. Why is a WNA mechanism necessary for UGI Gas's rate structure?

A. UGI Gas's current rate design recovers significant fixed costs through volumetric charges. Weather-driven usage swings can cause under-recovery in warm winters and over-recovery in cold winters. The WNA stabilizes this to provide the Company a reasonable

opportunity to recover its authorized revenue requirement while protecting customers from additional charges in colder than normal winters.

Q. Can you elaborate on the relationship between fixed costs and usage-based recovery in UGI Gas's current rate design?

A. UGI Gas's current rate design recovers a significant portion of its fixed costs, such as infrastructure, maintenance, and administrative expenses, through volumetric charges based on customer usage. Because revenues are recovered through volumetric rates established using billing determinants that reflect normal weather conditions, periods of warmer-than-normal weather result in lower-than-expected gas usage and corresponding under-recovery of fixed costs, even though those costs do not vary with consumption. Conversely, colder-than-normal weather can lead to over-recovery. This mismatch creates volatility for both customers and the utility. The WNA mechanism helps address this by normalizing revenues to reflect normal weather conditions, ensuring that fixed costs are recovered more consistently with what was authorized by the Commission when it approved current rates.

Q. What portion of UGI Gas's fixed costs is recovered through its current volumetric distribution charges?

A. As shown on UGI Gas Exhibit E – Proof of Revenue, at current rates, approximately 72% of base rate distribution revenues for Rate R is recovered through the volumetric distribution charge. For Rate N, approximately 81% of base rate distribution revenue is

recovered through the volumetric distribution charge. This clearly indicates that even though UGI Gas's distribution costs are fixed, there is a risk of over- or under-recovery, for the vast majority of costs, resulting in the need for the WNA.

Q. Are there alternative rate designs which more closely align fixed cost recovery with distribution charges and minimize potential under- and over-recovery due to weather?

A. Yes. Straight-Fixed-Variable ("SFV") rate design would accomplish that goal.

Q. How would a transition toward a SFV rate design help mitigate under- and over-recovery risks?

A. A transition to a SFV rate design would reduce UGI Gas's reliance on usage-based charges to recover fixed costs. Under the current structure, a significant portion of fixed costs, such as infrastructure and maintenance, are recovered through volumetric rates, making revenues highly sensitive to weather-driven consumption changes. SFV shifts recovery of fixed costs to a fixed monthly charge, ensuring that these costs are collected consistently regardless of seasonal usage fluctuations. This approach mitigates under-recovery risks during mild winters and over-recovery during colder-than-normal periods, providing greater revenue stability and aligning cost recovery with cost causation principles.

Q. How does UGI Gas's proposed WNA align with the factors the Commission may consider when evaluating this alternative ratemaking mechanism?

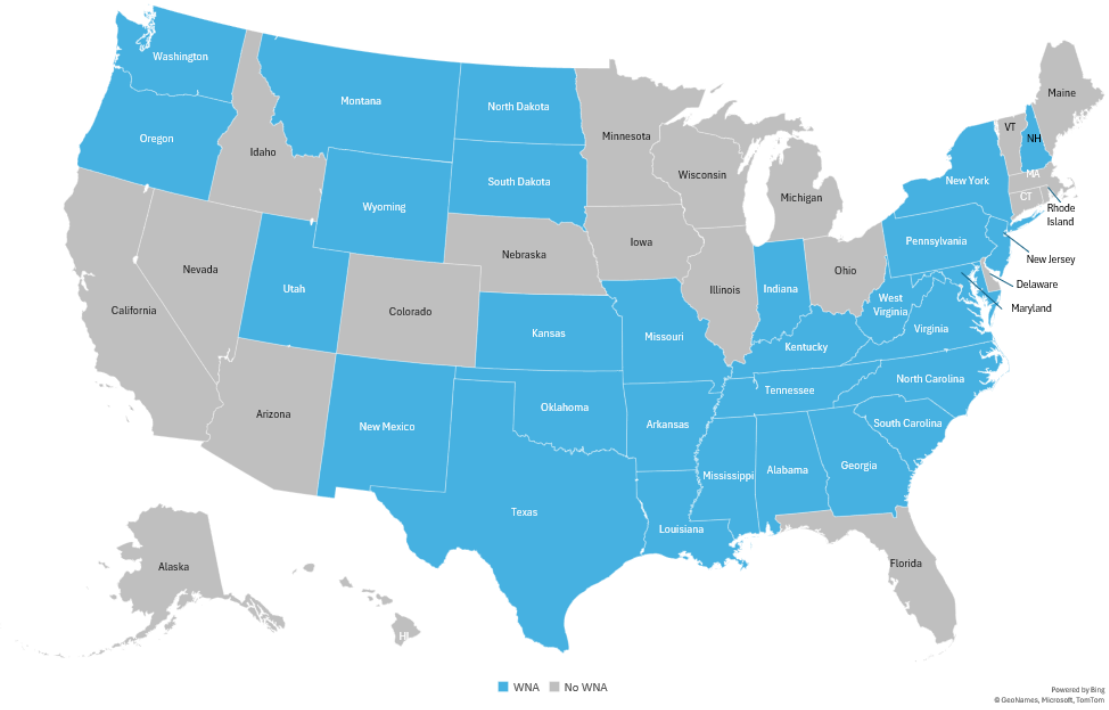
A. Exhibit JDT-4 details how UGI Gas's proposed WNA aligns with each of the fourteen items identified within the Statement of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883. However, it is important to note that the Statements of Policy language[14] suggests that the Commission intends to consider these elements, but not all of them may be relevant or deemed required in order to determine whether a proposal is just and reasonable.

Q. Are WNAs common alternative ratemaking mechanisms in the utility industry?

A. Yes. WNA mechanisms are widely used across the United States to stabilize customer bills and utility revenues during weather conditions that deviate from normal. The map that follows shows that 29 states with a total of 67 gas utilities have adopted similar mechanisms.

[14] "the Commission may consider, among other relevant factors, the following:" Docket M-2015-2518883 PA Bulletin Dated July 1, 2020 (https://www.puc.pa.gov/pcdocs/1633016.pdf)

Figure 1 – WNA in the United States



Q. Why should the Commission approve the continuation of UGI Gas's WNA pilot?

A. The continuation of UGI Gas's WNA pilot is reasonable because it supports the Company's ability to recover its Commission-authorized revenue requirement, which is based on prudently planned, just and reasonable costs incurred to provide safe and reliable service. In its most recent decision in Columbia's case, issued on December 2025, the Commission has recognized the role of weather normalization mechanisms in addressing weather-related revenue volatility by allowing the continuation of Columbia's WNA pilot. Further, as designed, the Company has already taken into consideration and adopted many modifications intended to provide greater transparency and more protections to customers,

as well as reasonable limitations previously supported by the parties and the Commission. For these reasons, UGI Gas's proposed WNA should be approved as filed.

VIII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Gas's ACOSS, class revenues, and rate design.

A. I recommend that the Commission approve the following:

- The Company's proposed ACOSS, as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system, and as a guide to evaluate and set UGI Gas's class revenues and rate design in this proceeding.
- The Company's proposed apportionment of revenues to its rate classes, because it reasonably balances the various criteria that the Company considered in the revenue apportionment process and moves classes towards their cost to serve.
- The rate design proposed by the Company, including the proposed customer charge increases, because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.
- The Company's proposal to extend the WNA pilot program through October 2032, along with alignment in the use of a 10-year period for defining normal weather for

the WNA, sales and billing determinants in this case, which address weather-driven revenue fluctuations, as the alternative ratemaking mechanism to recovering distribution fixed costs through a fixed charge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board
- Public Service Commission of West Virginia

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.

- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the development of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

TRANSACTION EXPERIENCE

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

FINANCIAL ANALYSIS AND MARKET RESEARCH

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost-of-service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

UGI GAS

EXHIBIT JDT-2

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

Normal Heating Degree Days ("NHDDs") Report and Recommendation

This report and recommendation was prepared in compliance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al., which established the following:

> (…) UGI Gas will include in its filing a report and recommendation on the use of a rolling ten-year historical average period to be used to calculate its normal heating degree day amounts for purposes of the WNA, as well as the use of a ten-year historical average period for purposes of determining projected sales and billing determinants in base rates.

I. Use of a ten-year historical average NHDD for base-rate billing determinants

Based on the analysis prepared by Atrium Economics of historic HDD data from 1975–2024, shown in Figure 1,[1] adopting a ten-year historical average is recommended. The long-term regression line demonstrates a persistent downward trend in HDDs, reflecting a period of ongoing warming over the last several decades, and provides useful directional context for evaluating normalization alternatives. Compared with 15-year average normals from two different recent periods (2005–2019[2] and 2010–2024) utilized by UGI Gas, the 10-year normal (2015–2024) more closely aligns with the current climate trajectory and the most recent observed weather patterns. Importantly, the 10-year historical average produces results that are closely aligned with the central tendency implied by the regression trend.

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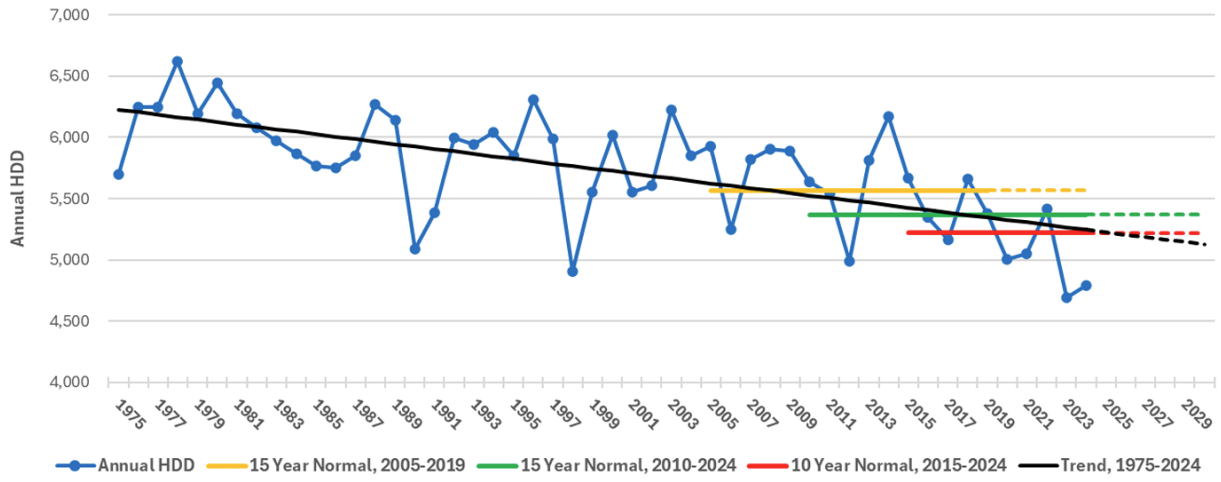
[1] Based on the composite average for the UGI Gas distribution system which is calculated as the weighted average of HDD data for the following weather stations: Wilkes-Barre/Scranton International Airport (KAVP) 22.2%, Bradford Regional Airport (KBFD) 16.3%, Reading Regional Airport (KRDG) 15.2%, Harrisburg International Airport (KMDT) 15.2%, Lancaster Airport (KLNS) 15.2%, Allentown Lehigh Valley International Airport (KABE) 15.2%, and Clearfield–Lawrence Airport (KFIG) 0.7%. The 50-year dataset utilized was obtained from AccuWeather.

[2] Period used to set NHDDs in the prior rate case for billing determinants as well as initial WNA NHDDs.

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

Figure 1 – Historic Annual HDD & Normalization Alternatives[3]



Using a longer period may overstate heating demand and inflate projected sales, leading to normalized usage assumptions that are not reflective of the conditions that customers are likely to experience during the fully projected future projected test year ("FPFTY") period. Therefore, a ten-year historical normal is more appropriate, more current, and more consistent with the observed trend of warming weather.

II. Use of a rolling ten-year historical average for WNA NHDD

Although the analysis above supports the conclusion that a ten-year average better represents recent warming trends, applying a rolling ten-year average specifically for WNA calculations is not recommended unless the same rolling approach is also used to determine base-rate billing determinants.

If base rates are set using a fixed ten-year normal (e.g., 2015–2024) while WNA calculations later transition to a different rolling ten-year period (e.g., 2016–2025), the WNA would compare actual weather to a baseline inconsistent with the rate-setting baseline. This misalignment could result in over- or under-correction relative to the assumptions embedded in customer rates, which

[3] Chart interpretation for grayscale / black-and-white printing:

- Annual HDD values are shown by the solid line with circular markers.
- The trend (1975–2024) is shown by a smooth solid line that slopes downward from left to right.
- The shorter horizontal reference lines near the right side of the chart are explained as follows:
  - The highest horizontal line corresponds to the 15-year normal for 2005–2019.
  - The middle horizontal line corresponds to the 15-year normal for 2010–2024.
  - The lowest horizontal line corresponds to the 10-year normal for 2015–2024.

is contrary to the WNA's objective of reconciling actual weather to the same normalized weather conditions used in establishing base rates.

Maintaining a consistent HDD baseline for both functions aligns with the overarching utility ratemaking "matching principle," which requires that the utility align revenue requirements and billing determinants within the same period and under the same assumptions when setting rates.[4] Therefore, rather than using a rolling period or defining a fixed frequency for recalculation, the Company recommends recalculating the NHDD ten-year average based on the most recently completed ten-year period that ended during the historic test year ("HTY"). In this case, that would be the ten-year period ending December 31, 2024.

III. Conclusion

In accordance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al.:

- It is recommended that the Company adopt a ten-year historical average HDD for determining projected sales and billing determinants in base rates, as the Figure 1 graph clearly demonstrates that a ten-year period reflects recent warming trends and closely tracks the directional signal indicated by the long-term regression analysis making it a reasonable and supportable normalization period.
- It is not recommended to adopt a rolling ten-year historical average for WNA calculations unless the Commission also intends to adopt the use of a rolling period for base-rate normalization between rate cases. Using different normals for rate-setting and WNA reconciliation could introduce inconsistency and unintended outcomes.

This approach maintains methodological integrity, aligns with observed weather trends, and complies with the Settlement’s reporting requirements.

[4] National Regulatory Research Institute, *Future Test Years: Evidence from State Utility Commissions*, Report No. 13-10, at 5 (Oct. 2013), available at https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361

UGI GAS

EXHIBIT JDT-3

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Total Number of Bills	657,848	690,784	702,630	637,189	757,679	644,611	723,767
R/RT and N/NT	Number of Bills with WNA	494,845	335,446	609,400	605,793	709,079	588,357	503,561
R/RT and N/NT	Billed WNA Volume Adj (ccf)	3,349,172	2,246,101	13,453,826	24,268,267	20,479,847	9,423,352	1,105,684
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 1,536,159	$ 1,021,184	$ 6,152,516	$ 10,999,357	$ 9,194,818	$ 4,311,784	$ 487,940
R/RT	Total Number of Bills	591,744	621,058	631,171	573,017	680,249	580,105	650,634
R/RT	Number of Bills with WNA	447,992	301,310	550,669	547,010	639,251	532,148	455,315
R/RT	Billed WNA Volume Adj (ccf)	2,153,568	1,439,549	8,647,924	15,124,980	12,723,261	6,098,146	566,866
R/RT	Billed WNA Revenue Adj ($)	$ 1,080,819	$ 716,506	$ 4,334,131	$ 7,543,041	$ 6,319,132	$ 3,049,904	$ 283,485
N/NT	Total Number of Bills	66,104	69,726	71,459	64,172	77,430	64,506	73,133
N/NT	Number of Bills with WNA	46,853	34,136	58,731	58,783	69,828	56,209	48,246
N/NT	Billed WNA Volume Adj (ccf)	1,195,604	806,552	4,805,902	9,143,287	7,756,586	3,325,206	538,818
N/NT	Billed WNA Revenue Adj ($)	$ 455,340	$ 304,678	$ 1,818,385	$ 3,456,316	$ 2,875,687	$ 1,261,880	$ 204,455

Data Presented By Calendar Month

Region	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	692	987	1,166	998	858	447	181
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	594	982	846	800	791	341	206
UGI Gas - North	Calendar Month - Normal Heating Degree Days	837	1,130	1,313	1,154	1,027	605	303
UGI Gas - North	Calendar Month - Actual Heating Degree Days	725	1,088	1,001	878	942	459	299
UGI Gas - South	Calendar Month - Normal Heating Degree Days	632	905	1,066	911	744	365	130
UGI Gas - South	Calendar Month - Actual Heating Degree Days	555	933	775	701	673	273	129
UGI Gas - West	Calendar Month - Normal Heating Degree Days	781	1,067	1,230	1,056	896	498	220
UGI Gas - West	Calendar Month - Actual Heating Degree Days	712	1,102	948	823	876	423	249

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Bill Count Total	661,595	682,807	699,952	639,135	760,059	640,522	722,158
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	495,114	263,607	612,172	607,639	710,022	583,773	246,153
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	74.8%	38.6%	87.5%	95.1%	93.4%	91.1%	34.1%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	21,005	60,755	243	92	531	311	247,613
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	3.2%	8.9%	0.0%	0.0%	0.1%	0.0%	34.3%
R/RT and N/NT	Bill Count without WNA Charges/Credits	145,476	358,445	87,537	31,404	49,506	56,438	228,392
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	22.0%	52.5%	12.5%	4.9%	6.5%	8.8%	31.6%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Total Number of Bills	679,115	672,095	750,421	666,627	712,202	673,107	669,970
R/RT and N/NT	Number of Bills with WNA	5,354	72	5	15	211,543	456,224	460,215
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(18,930)	723	(1,020)	1,221	568,839	2,700,175	4,775,793
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (7,892)	$ 22	$ (393)	$ 454	$ 258,355	$ 1,280,999	$ 2,267,281
R/RT	Total Number of Bills	610,673	604,474	673,177	598,915	640,299	605,796	602,536
R/RT	Number of Bills with WNA	4,668	64	1	14	187,839	412,231	413,761
R/RT	Billed WNA Volume Adj (ccf)	(6,314)	(1,522)	36	(99)	324,373	1,828,070	3,242,561
R/RT	Billed WNA Revenue Adj ($)	$ (3,158)	$ (790)	$ 10	$ (50)	$ 164,836	$ 946,337	$ 1,678,848
N/NT	Total Number of Bills	68,442	67,621	77,244	67,712	71,903	67,311	67,434
N/NT	Number of Bills with WNA	686	8	4	1	23,704	43,993	46,454
N/NT	Billed WNA Volume Adj (ccf)	(12,616)	2,245	(1,057)	1,320	244,467	872,105	1,533,232
N/NT	Billed WNA Revenue Adj ($)	$ (4,735)	$ 812	$ (402)	$ 504	$ 93,519	$ 334,662	$ 588,432

Data Presented By Calendar Month

Region	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	35	3	10	96	376	692	987
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	51	0	5	107	320	724	786
UGI Gas - North	Calendar Month - Normal Heating Degree Days	104	42	65	202	523	837	1,130
UGI Gas - North	Calendar Month - Actual Heating Degree Days	111	8	32	159	407	773	843
UGI Gas - South	Calendar Month - Normal Heating Degree Days	11	0	2	54	306	632	905
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	0	0	47	261	647	728
UGI Gas - West	Calendar Month - Normal Heating Degree Days	54	13	26	147	453	781	1,067
UGI Gas - West	Calendar Month - Actual Heating Degree Days	80	1	18	144	408	691	763

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Bill Count Total	0	0	0	0	727,098	668,042	663,445
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	0	0	184,540	431,193	470,364
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	25.4%	64.5%	70.9%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	0	0	55,602	7,234	3,747
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	7.6%	1.1%	0.6%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	0	0	486,956	229,615	189,334
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	67.0%	34.4%	28.5%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Total Number of Bills	724,592	681,980	682,512	725,300	721,146	679,265	734,574
R/RT and N/NT	Number of Bills with WNA	681,099	645,482	646,595	664,738	586,262	30,534	499
R/RT and N/NT	Billed WNA Volume Adj (ccf)	17,463,903	19,299,656	25,201,442	10,508,920	6,187,180	451,727	(15,683)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 8,167,157	$ 9,077,681	$ 11,847,340	$ 4,906,085	$ 2,918,063	$ 199,054	$ (6,443)
R/RT	Total Number of Bills	651,291	613,382	613,650	652,736	648,873	611,382	660,330
R/RT	Number of Bills with WNA	614,798	583,134	583,894	601,058	531,639	27,271	314
R/RT	Billed WNA Volume Adj (ccf)	10,942,912	12,481,667	16,251,546	6,519,900	4,057,503	191,750	(2,927)
R/RT	Billed WNA Revenue Adj ($)	$ 5,664,520	$ 6,461,106	$ 8,412,549	$ 3,375,181	$ 2,100,742	$ 99,280	$ (1,548)
N/NT	Total Number of Bills	73,301	68,598	68,862	72,564	72,273	67,883	74,244
N/NT	Number of Bills with WNA	66,301	62,348	62,701	63,680	54,623	3,263	185
N/NT	Billed WNA Volume Adj (ccf)	6,520,991	6,817,989	8,949,897	3,989,020	2,129,677	259,977	(12,756)
N/NT	Billed WNA Revenue Adj ($)	$ 2,502,636	$ 2,616,575	$ 3,434,791	$ 1,530,905	$ 817,321	$ 99,773	$ (4,895)

Data Presented By Calendar Month

Region	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	1,166	1,031	858	447	181	35	3
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	1,026	860	648	378	111	8	0
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,313	1,193	1,027	605	303	104	42
UGI Gas - North	Calendar Month - Actual Heating Degree Days	1,133	920	754	474	157	56	8
UGI Gas - South	Calendar Month - Normal Heating Degree Days	1,066	941	744	365	130	11	0
UGI Gas - South	Calendar Month - Actual Heating Degree Days	944	771	559	304	82	1	0
UGI Gas - West	Calendar Month - Normal Heating Degree Days	1,230	1,091	896	498	220	54	13
UGI Gas - West	Calendar Month - Actual Heating Degree Days	1,052	879	675	420	141	36	2

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Bill Count Total	731,791	680,203	676,080	730,279	728,083	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	688,451	643,676	639,931	666,340	587,492	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	94.1%	94.6%	94.7%	91.2%	80.7%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	508	3	369	899	175	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	42,832	36,524	35,780	63,040	140,416	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	5.9%	5.4%	5.3%	8.6%	19.3%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
R/RT and N/NT	Total Number of Bills	728,175	669,948	751,839	652,863	690,188	742,545	647,127
R/RT and N/NT	Number of Bills with WNA	128	(2)	288,385	559,418	427,644	415,714	426,511
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(6,104)	(4,027)	1,723,324	8,405,258	2,957,527	(3,100,199)	(3,255,501)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (2,527)	$ (1,704)	$ 795,006	$ 3,968,165	$ 1,388,659	$ (1,431,770)	$ (1,513,534)
R/RT	Total Number of Bills	653,863	603,292	674,662	588,776	621,163	667,793	582,802
R/RT	Number of Bills with WNA	39	(4)	259,212	508,986	385,192	373,211	384,270
R/RT	Billed WNA Volume Adj (ccf)	(1,295)	(1,207)	996,923	5,538,982	1,887,330	(1,812,212)	(1,975,349)
R/RT	Billed WNA Revenue Adj ($)	$ (675)	$ (621)	$ 516,234	$ 2,868,153	$ 977,916	$ (937,443)	$ (1,022,233)
N/NT	Total Number of Bills	74,312	66,656	77,177	64,087	69,025	74,752	64,325
N/NT	Number of Bills with WNA	89	2	29,173	50,432	42,452	42,503	42,241
N/NT	Billed WNA Volume Adj (ccf)	(4,809)	(2,820)	726,400	2,866,276	1,070,197	(1,287,987)	(1,280,152)
N/NT	Billed WNA Revenue Adj ($)	$ (1,852)	$ (1,082)	$ 278,772	$ 1,100,013	$ 410,743	$ (494,327)	$ (491,302)

Data Presented By Calendar Month

Region	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	10	96	376	692	987	1,166	998
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	19	48	315	627	1,030	1,266	999
UGI Gas - North	Calendar Month - Normal Heating Degree Days	65	202	523	837	1,130	1,313	1,154
UGI Gas - North	Calendar Month - Actual Heating Degree Days	43	79	406	681	1,061	1,364	1,103
UGI Gas - South	Calendar Month - Normal Heating Degree Days	2	54	306	632	905	1,066	911
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	25	244	516	912	1,173	891
UGI Gas - West	Calendar Month - Normal Heating Degree Days	26	147	453	781	1,067	1,230	1,056
UGI Gas - West	Calendar Month - Actual Heating Degree Days	25	74	388	655	1,021	1,310	1,019

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
R/RT and N/NT	Bill Count Total	0	0	766,628	629,649	703,828	730,792	653,438
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	323,925	546,068	319,684	32,920	22,900
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	42.3%	86.7%	45.4%	4.5%	3.5%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	1,074	38	107,240	386,799	388,472
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.1%	0.0%	15.2%	52.9%	59.5%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	441,629	83,543	276,904	311,073	242,066
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	57.6%	13.3%	39.3%	42.6%	37.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
R/RT and N/NT	Total Number of Bills	716,321	709,895	709,872	713,760	735,660	705,888	701,197
R/RT and N/NT	Number of Bills with WNA	522,521	637,555	484,433	19,813	57	18	(25)
R/RT and N/NT	Billed WNA Volume Adj (ccf)	9,366,210	12,277,590	6,286,389	45,793	(12,712)	(2,385)	(3,696)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 4,406,295	$ 5,750,700	$ 2,950,691	$ 21,098	$ (5,680)	$ (1,002)	$ (1,347)
R/RT	Total Number of Bills	644,559	639,457	638,553	642,608	661,589	635,194	631,059
R/RT	Number of Bills with WNA	470,537	576,765	439,236	17,805	9	18	(20)
R/RT	Billed WNA Volume Adj (ccf)	6,060,757	7,757,939	4,018,315	20,549	(10,066)	(1,113)	(2,077)
R/RT	Billed WNA Revenue Adj ($)	$ 3,137,726	$ 4,016,147	$ 2,080,248	$ 11,410	$ (4,836)	$ (514)	$ (1,075)
N/NT	Total Number of Bills	71,762	70,438	71,319	71,152	74,071	70,694	70,138
N/NT	Number of Bills with WNA	51,984	60,790	45,197	2,008	48	-	(5)
N/NT	Billed WNA Volume Adj (ccf)	3,305,453	4,519,651	2,268,074	25,244	(2,646)	(1,272)	(1,619)
N/NT	Billed WNA Revenue Adj ($)	$ 1,268,569	$ 1,734,552	$ 870,443	$ 9,688	$ (844)	$ (488)	$ (272)

Data Presented By Calendar Month

Region	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	858	447	181	35	3	10	96
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	667	425	219	31	3	43	38
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,027	605	303	104	42	65	202
UGI Gas - North	Calendar Month - Actual Heating Degree Days	748	496	318	61	18	116	175
UGI Gas - South	Calendar Month - Normal Heating Degree Days	744	365	130	11	0	2	54
UGI Gas - South	Calendar Month - Actual Heating Degree Days	553	318	114	15	0	11	8
UGI Gas - West	Calendar Month - Normal Heating Degree Days	896	498	220	54	13	26	147
UGI Gas - West	Calendar Month - Actual Heating Degree Days	698	464	268	39	1	65	87

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
R/RT and N/NT	Bill Count Total	709,220	714,780	708,205	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	535,815	638,314	465,363	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	75.5%	89.3%	65.7%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	26	2,067	8,174	0	0	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.3%	1.2%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	173,379	74,399	234,668	0	0	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	24.4%	10.4%	33.1%	0.0%	0.0%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Total Number of Bills	762,059
R/RT and N/NT	Number of Bills with WNA	281,147
R/RT and N/NT	Billed WNA Volume Adj (ccf)	803,710
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 374,502
R/RT	Total Number of Bills	684,790
R/RT	Number of Bills with WNA	253,447
R/RT	Billed WNA Volume Adj (ccf)	497,914
R/RT	Billed WNA Revenue Adj ($)	$ 257,422
N/NT	Total Number of Bills	77,269
N/NT	Number of Bills with WNA	27,700
N/NT	Billed WNA Volume Adj (ccf)	305,796
N/NT	Billed WNA Revenue Adj ($)	$ 117,080

Data Presented By Calendar Month

Region	Reporting Item	2025 OCT
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	341
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	398
UGI Gas - North	Calendar Month - Normal Heating Degree Days	473
UGI Gas - North	Calendar Month - Actual Heating Degree Days	530
UGI Gas - South	Calendar Month - Normal Heating Degree Days	279
UGI Gas - South	Calendar Month - Actual Heating Degree Days	309
UGI Gas - West	Calendar Month - Normal Heating Degree Days	429
UGI Gas - West	Calendar Month - Actual Heating Degree Days	469

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Bill Count Total	770,361
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	225,621
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	29.3%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	83,898
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	10.9%
R/RT and N/NT	Bill Count without WNA Charges/Credits	460,842
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	59.8%

UGI GAS

EXHIBIT JDT-4

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	**Statement of Policy**	**Company's Response**
1	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	UGI Gas's WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. The Company recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.
2	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company's gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company's ability to make prudent investments necessary to maintain safe and reliable service.
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer's anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 10-year

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	**Statement of Policy**	**Company's Response**
	customer's anticipated consumption levels.	average rather than a 15-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions. Please refer to UGI Gas Exhibit JDT-2.
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	UGI Gas's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.
5	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.
6	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.
7	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.	In accordance with the Settlement Agreement in Docket Nos. R-2024-3052716, et al., the current WNA mechanism does not apply to low-income customers enrolled in the Company's Customer Assistance Program ("CAP").
8	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	**Statement of Policy**	**Company's Response**
		called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.
9	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months of October through April, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.
10	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	The WNA does not impact the Company's rate case frequency nor it effects regulatory lag.
11	If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).	The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through April. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.

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#	Statement of Policy	Company's Response
12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	UGI Gas's WNA includes several consumer protections to ensure fairness and transparency, as follows: a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and outside of the deadband the WNA results in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. b. No Cross-Subsidization: The WNA is customer-specific. c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts. d. Customer Transparency and Education: UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.
13	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. As indicated above, UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.
14	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudency and reasonableness would have been reviewed and deemed appropriate to support reliability driven

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	**Statement of Policy**	**Company's Response**
		initiatives. The proposed WNA would help minimize the volatility of the recovery of these costs.

UGI GAS STATEMENT NO. 12

BRIAN J. MEILINGER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 12

Direct Testimony of
Brian J. Meilinger

Topics Addressed: **Universal Service Programs**
Strategic Initiatives
Low-Income Customer Counts
Weather Normalization Adjustment ("WNA") Communications Revisions

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian J. Meilinger. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed, and what is your current position?

A. I am employed by UGI Utilities, Inc. ("UGI") as Director, Customer Programs & Public Relations. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC"). In this role, I am responsible for directing the Company's Energy Efficiency & Conservation, Universal Service, Community Relations, and Public Relations Departments.

Q. What is your educational and professional background?

A. I graduated from Ursinus College with a B.A. in Economics & Business Administration and Saint Joseph's University with an MBA in Finance. I started my employment with UGI in 2012. My full resume is attached as UGI Gas Exhibit BJM-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company").

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the significant efforts that UGI Gas has undertaken to make sure that its customers have access to affordable utility service. Customer affordability is a core focus at UGI Gas. This is evident from the success of the Company's many customer programs, as well as the Company's commitment to voluntarily donate $1 million annually per year for the next three years (FY27, FY28, and FY29) to Operation Share. I will discuss these efforts in greater detail below.

Q. How is your direct testimony organized?

A. My direct testimony (1) describes how UGI's Universal Service Programs have helped customers afford their utility bills, (2) provides an overview of strategic initiatives to drive increased customer participation in Universal Service Programs and address customer affordability concerns, including the Company's commitment to donate $1 million annually to Operation Share for the next three years; (3) provides data regarding the Company's low-income customer counts, and (4) addresses the Company's compliance with paragraph 58(a) of the Joint Petition for Approval of Settlement of All Issues at Docket No. R-2024-3052716 ("2025 Settlement") regarding Weather Normalization Adjustment ("WNA") pilot communications.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, UGI Gas Exhibit BJM-1 provides a list of the proceedings in which I have testified.

II. UNIVERSAL SERVICE PROGRAMS

Q. Does UGI Gas have a Universal Service and Energy Conservation Program ("USECP")?

A. Yes. The USECP is a comprehensive plan that covers the Company's universal service programs. In accordance with the Commission's Universal Service and Energy Conservation Reporting Requirements at 52 Pa. Code §§ 54.71 – 54.78 and §§ 62.1 – 62.8, UGI Gas submits a USECP every five years for the Commission's review and approval.

Q. Did UGI Gas recently file its USECP for the five-year period January 1, 2026, through December 31, 2030?

A. Yes. The Company filed its 2026-2030 USECP on April 1, 2025, at Docket Nos. M-2025-3054362 and M-2025-3054366. The parties submitted comments on October 6, 2025, and reply comments on November 10, 2025.

Q. Is UGI Gas proposing any changes to its USECP as a part of this base rate proceeding?

A. No. However, UGI Gas intends to update its USECP with the $1 million donation to Operation Share through 2029 as described in my testimony.

Q. Can you please provide an overview of the Company's USECP?

A. The Company offers four programs under its USECP that assist low income customers: (1) Customer Assistance Program ("CAP"); (2) the Hardship Fund (i.e., Operation Share); (3) Low Income Usage Reduction Program ("LIURP"); and (4) the Customer Assistance Referral and Evaluation Services ("CARES").

CAP provides discounted monthly bills and arrearage forgiveness for low-income customers at or below 150% Federal Poverty Income Guidelines ("FPIG"). CAP payments are calculated based on a percentage of a customer's monthly income, also known as a Percentage of Income ("PIP") amount, or a CAP participant's average monthly bill, if lower. For gas heating customers, maximum monthly CAP payments are set at 4% of income for customers with household incomes between 0-50%, and 6% of income for customers with household incomes between 51-150% FPIG. CAP participants with no income are placed on the monthly minimum payment which is $25 for gas heating and $15 for non-heating gas service.

Operation Share provides grants of up to $600 for eligible customers with household incomes up to 250% FPIG who are having difficulty paying their bill. In special circumstances, the Company may provide exceptions to the maximum grant amount of $600. In order to qualify for a grant, the following criteria must be met:

- Customer must have a residential account with their premise being the customer's primary residence;
- The customer must have an active heating or non-heating account;
- A customer must not have received the maximum Operation Share grant amount in the prior 12 months, unless in situations of special circumstance as determined by the Company;
- A customer must have an outstanding balance;
- A customer must provide proof of identification and adequate information to demonstrate the inability to pay their bill;
- Customers whose service has been terminated must contact the UGI Credit Department to discuss their options as Community Based Organizations ("CBOs") cannot provide benefits on an inactive account.

The Company's LIURP offers weatherization services to low-income customers with household incomes up to 200% FPIG. To qualify, a customer must have above

average annual usage, defined as exceeding the average residential threshold by 30%, or 877 CCF. Additionally, a customer must not have received LIURP in the prior 7 years and must have twelve months of continuous service.

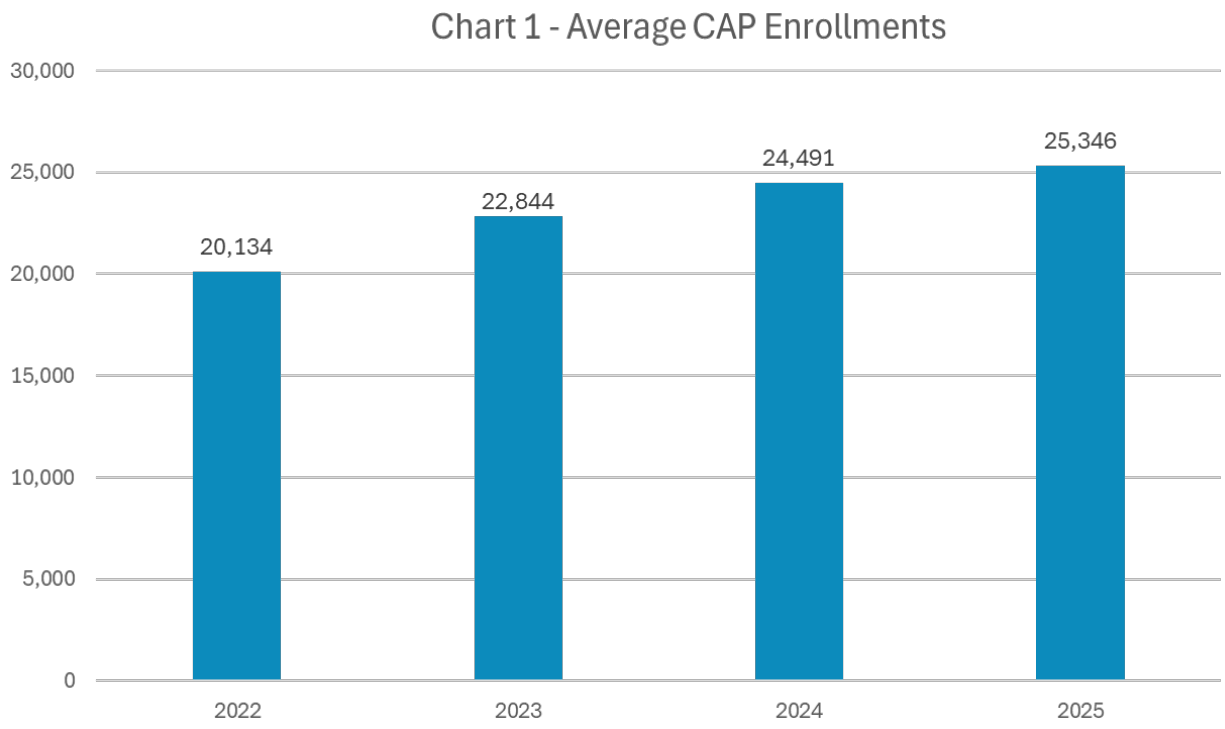
CARES offers customers referral services to other community support programs which may include, but are not limited to LIHEAP, budget counseling, State Weatherization, Office of Aging, etc. There are no income requirements to participate in CARES.

Q. Has the Company's CAP helped low-income customers afford their utility bills?

A. Yes. The Company's CAP has performed well both in terms of increasing customer enrollments and helping make customers' bills more affordable.

Q. How has the Company's CAP enrollment increased from prior years?

A. The Company's average CAP enrollment for 2025 was 25,346 customers, which represents a 3% increase over 2024, and a 26% increase over 2022 CAP average enrollment of 20,134. Please see Chart 1 below for details regarding the growth in UGI Gas CAP enrollments since 2022.



The significant growth in CAP enrollments is a direct result of the Company's efforts to reach as many low-income customers as possible. For instance, the Company undertook a project to assess, identify, and engage with low-income customers in 2023-2024. The Company utilized the services of Experian to help identify potential low-income customers and then performed targeted marketing via email and direct mail with a call to action to visit the Company's CAP landing page to screen for program eligibility. This campaign resulted in approximately 780 customers enrolling in CAP.

Q. How has CAP worked to make customers' bills more affordable?

A. In 2024, the Company provided its CAP customers with approximately $3.8 million of Pre-Program Arrearage ("PPA") forgiveness and $10.6 million CAP Shortfall and in 2025, $3.7 million and $15.9 million respectively. The PPA component of CAP is a benefit to customers, as it provides arrearage forgiveness over a 36-month time period if customers

continue making timely and in full monthly CAP payments. For instance, a customer entering CAP with $2,500 of arrearage would have $69.44 ($2,500/36) forgiven each month assuming the customer continues making monthly CAP payments in full. CAP Shortfall is another significant benefit, as customers are not responsible for monthly costs incurred above the CAP bill. For example, a CAP customer on the Percent of Income Plan with a $50 per month CAP bill that incurs a usage-based bill calculated at $150, would not be responsible for the entire bill amount, just the $50.

Q. What are the Company's plans to continue building upon the growth in CAP customer enrollments?

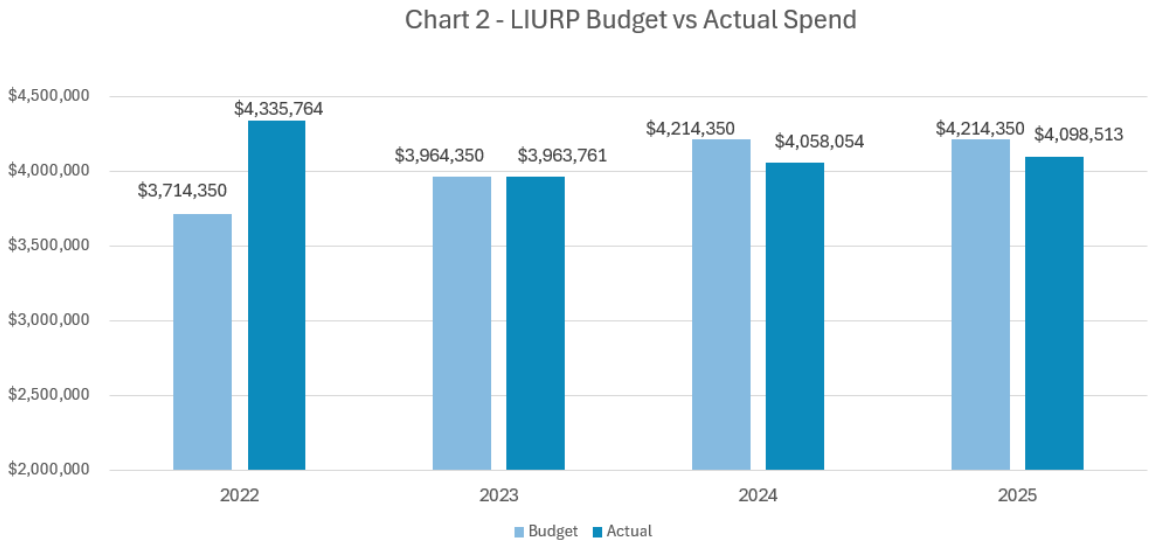
A. The Company continues to focus on increasing customer enrollment in CAP through its marketing efforts that include ongoing general outreach efforts throughout the year and twice a year personalized outreach via email and direct mail to customers who are self-certified low income and to LIHEAP recipients that are not currently enrolled in CAP. The Company is also continuing its Low Income Customer Assessment and Outreach Pilot through 2028 as further described in section III below.

Q. How has the Company's LIURP helped customers?

A. The Company has successfully partnered with 15 weatherization CBOs and contractors to maximize its PUC-approved budgets. Since 2022, the following results were achieved which indicate that UGI Gas has been highly effective at achieving spending to budget:

- 2022: 117% of budget utilization (rollover of unspent budget from prior year)
- 2023: 100% of budget utilization

- 2024: 96% of budget utilization
- 2025: 97% budget utilization



During the 2022-2025 timeframe, the Company's weatherization contractors completed 2,133 LIURP jobs, or an average of 533 per year. As part of the 2025 Settlement, Paragraph 60(a), the Company has agreed to increase its budget effective January 1, 2026, by $1,000,000 from $4,214,350 to $5,214,350 with any unspent budget rolling over to the next year wherein it will make best efforts to spend it within the first six months of the following year. In addition, UGI Gas will comply with the final order issued in the LIURP rulemaking proceeding at Docket No. L-2016-2557886.

Q. Has the Company's Operation Share Program helped customers?

A. Yes. During the 2022-2025 timeframe, the Company has issued nearly 12,000 Operation Share grants for approximately $4.2 million to customers needing assistance. Furthermore, as part of the UGI Gas 2025 Settlement, Paragraph 62(a), the Company increased its Operation Share commitment by $500,000 from $584,500 to $1,084,500 and

was permitted to increase the annual budget reallocation limitation across the geographic footprint of its former three rate districts from 5% to 50% (Paragraph 62(b)). Collectively, these settlement provisions provide an increased budget and greater flexibility to reallocate budgets and avoid stranded funding by region, which has occurred in the past.

Q. Has UGI Gas undertaken any additional voluntary efforts to support its low-income customers?

A. Yes. In November 2025, in an attempt to offset impacts to low-income customers due to LIHEAP funding delays resulting from the Federal Government shutdown, the Company made a one-time supplemental donation of $500,000, allocated between the Gas and Electric Divisions, to Operation Share for Fiscal Year 2026. I describe the LIHEAP funding delay in greater detail below. This additional donation brought UGI's contribution to Operation Share to more than $1.5 million for Fiscal Year 2026.

Q. Are there other programs available to assist payment-troubled customers?

A. Yes. In addition to the UGI Gas Universal Service Programs, there are external programs to support payment-troubled customers. These state and federally funded programs include, but are not limited to:

- The Low Income Home Energy Assistance Program ("LIHEAP") provides energy grants which help customers restore and/or maintain service, as well as repair or replace broken heating equipment. The LIHEAP season typically runs from November 1 through April 1. However, in some years, the season is extended pending funding availability. UGI Gas receives a weekly customer voucher file from the Department of Human Services ("DHS") which contains details of the grant amounts, typically up to a maximum of $1,000 per customer, who have gone through DHS's income verification processes and are determined to be at or below 150% FPIG. UGI Gas then applies these grant amounts to customer accounts.

- The Pennsylvania Weatherization Assistance Program ("WAP") reduces energy costs and increases comfort while ensuring homes are healthier and safer. WAP services include a variety of measures that are provided (when necessary) to allow the safe and effective installation of weatherization measures. It also provides client education on the proper use and maintenance of the installed weatherization measures and ways to reduce energy waste. The average expenditure per household is $7,669 depending on the results of a home audit.[1]

Q. How much assistance has LIHEAP provided over the past three seasons?

A. Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly $32 million. This funding has been instrumental in assisting low-income customers in maintaining and/or restoring natural gas service as well as emergency furnace repair or replacement. For the 2025-2026 LIHEAP season that had a delayed start date of early December, the Company has already facilitated the processing of approximately 10,106 grants for $2.6 million.

Q. What actions did the Company take to help offset the customer impacts that could have resulted from the delay in LIHEAP launching for the 2025/2026 season?

A. In addition to the proactive $500,000 supplemental Operation Share Company contribution mentioned earlier, the Company's efforts described below were designed to provide additional assistance to customers and minimize terminations during the delay in LIHEAP funding until the program resumed in December 2025.

Active Income Verified Low-Income Customers (150% FPIG):

- Effective November 1, 2025, UGI temporarily suspended field terminations for non-payment for CAP customers. The Company also worked to maximize any available Operation Share grants to assist with arrears. If an Operation Share grant had already been applied during the year, consistent with its USECP, the Company provided a one-time Operation Share grant in excess of the individual

[1] https://dced.pa.gov/programs/weatherization-assistance-program-wap/.

maximum of $600 to help maintain the customer's service as active. For this initiative, if a customer was behind in CAP payments totaling $900 or less, the maximum grant issued was $900. There were 2,703 Operation Share grants for approximately $598,000 issued to customers in need during the month of November.

- Effective November 1, 2025, UGI temporarily suspended field terminations of active customers in arrears who received LIHEAP within the last 12 months and were not enrolled in CAP. The Company continued its Dunning notices during this timeframe to encourage customers to contact the Company and enroll in a Universal Service Program.
    - The Company actively solicited these customers via auto dialer and by email requesting they immediately contact UGI to enroll in CAP to keep service active.
    - For these customers that received LIHEAP in the prior season, they were offered streamlined enrollment into CAP and did not have to provide proof of income to enroll.

Inactive Income Verified Low-Income Customers (150% FPIG & Already Terminated for Non-Payment):

- For inactive income verified low-income customers (150% FPIG) that contacted the UGI Call Center about their service that had been terminated for non-payment, UGI representatives reviewed options with the customer about enrolling in CAP. If the customer agreed to and was qualified to enroll in CAP, their service was reconnected, and an Operation Share grant was applied to their account. For inactive income verified low-income CAP customers (150% FPIG) that contacted the UGI Call Center about their service that was terminated for non-payment, the Company applied an Operation Share grant to their account to help offset their arrears and turn service back on.

Q. What impacts did these actions have in November and December 2025?

A. The success of the Company's efforts during the November and December 2025 timeframe was substantial. Company representatives worked approximately 250 hours of overtime to provide additional assistance to customers who may have been impacted by the Government Shutdown. Highlights are summarized below:

- 421 confirmed low income customers were enrolled in CAP and either reconnected or not terminated;
- 3,450 Operation Share grants, totaling $905,233 were issued in November and December 2025. This can be compared to 332 grants for $110,201 during this same time period in 2024.

III. STRATEGIC INITIATIVES

Q. What actions has the Company undertaken to maximize customer enrollment in Universal Service Programs?

A. As part of the 2025 Settlement, the Company implemented several noteworthy changes to its Universal Service Programs. First, the Company increased its LIURP budget substantially by $1,000,000 or approximately 24% from $4,214,350 in calendar year 2025 to $5,214,350 in calendar year 2026. For any unspent LIURP budget, those funds will rollover to the next year to be utilized within the first six months of the following year to the extent possible. Second, the Company substantially increased its Operation Share contribution by $500,000 or approximately 86% from $584,500 in Fiscal Year 2025 to $1,084,500 in Fiscal Year 2026 and added increased flexibility to reallocate program funding from a previous maximum of only 5% to now 50% of funding between the Company's former rate districts to minimize underspending and to assist customers in need. Third, the Company is undertaking expanded outreach efforts in 2026 through additional in person Winter Assistance Relief Mobilization ("WARM") events held at targeted locations each year, with a minimum of 6 events in Lancaster, 4 events in Wilkes Barre, and 3 events in Williamsport. Each year thereafter, the Company will target a

minimum of three new cities within its service territory as set forth in its tariff, which will be identified in consultation with its Universal Service Advisory Committee. Furthermore, the Company began engaging with various Mayor's offices throughout the UGI Gas service territory to provide the Company's Universal Service brochure in an effort to promote awareness of the Company's low-income assistance programs. Locations for outreach include Allentown, Bethlehem, Easton, Harrisburg, Hazleton, Lancaster, Lock Haven, Pottsville, Reading, Scranton, Wilkes-Barre, and Williamsport. Fourth, the Company is continuing its Low Income Customer Assessment and Outreach Pilot as agreed to in the UGI Gas 2025 Settlement (Paragraph 61(a)) with an annual budget not to exceed $120,000. The purpose of this Pilot is to engage in additional outreach to the Company's estimated low-income customers up to 150% FPIG identified by third-party consumer credit reporting agency Experian. UGI Gas intends to utilize email, direct mail, and digital ads for targeted marketing to these customers. Customers will be directed to a landing page where they can learn more about the process to pursue enrollment in the Company's CAP. Fifth, UGI Gas has adopted the PUC Common Application Form as of December 2025. Finally, the Company has been participating in the DHS data sharing process and has been analyzing this data and evaluating methods to use this information to further promote the availability of the UGI Gas Universal Service Programs. Examples include outreach to data sharing participants who have not yet enrolled in CAP, as well as utilizing the data sharing file to recertify customers for CAP.

Q. What does UGI intend to do to further address affordability concerns for its customers?

A. UGI recognizes the importance of supporting the affordability of utility bills for its low-income customers. That is why the Company is committing to contribute $1,000,000 annually to Operation Share in Fiscal Years 2027, 2028, and 2029. This multi-year commitment is unprecedented in the Company's history and will provide substantial assistance to low and moderate income customers with income levels up to 250% FPIG.

IV. CONFIRMED LOW-INCOME CUSTOMER COUNTS

Q. Did UGI previously identify inconsistencies with regulatory reporting of confirmed low-income customer counts on prior Universal Service Reports ("USR")?

A. Yes. During the 2025 UGI Gas Base Rate Case, it was discovered that the Company had inadvertently reported self-certified low-income customers up to 250% FPIG on prior USR filings; however, the Company should have reported only those customers up to 150% FPIG. Therefore, the Company's confirmed low-income customer counts on prior USR were affected by unintentional data inconsistencies that increased the number of customers included.

Q. Has UGI Gas taken steps to ensure that its internal tracking of the "confirmed low-income" designation for Universal Service Reporting and USECP purposes has become more accurate?

A. Yes. In 2025, the Company made information technology ("IT") system enhancements to ensure that future Universal Service Reports will include self-certified low-income customers up to 150% FPIG, not 250% FPIG as was previously reported in prior years.

This enhancement includes leveraging a more suitable data source, which directly supports the reporting questions being asked. However, significant time and effort to thoroughly vet and cleanse the data was required, which could not be achieved retrospectively. As a result, the 2025 USR confirmed low-income count may result in an overstatement of confirmed low-income counts. The Company anticipates that the confirmed low income counts that will be included on the 2026 Universal Service Report and filed in April 2027, will accurately reflect self-certified low-income customers up to 150% FPIG. Importantly, the Company's definition of "Confirmed Low Income" is now consistent with the PUC's regulations at 52 Pa. Code § 62.2, which defines a "confirmed low-income residential account" to include "[a]ccounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds, self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon ratepayer or occupant contact prior to termination)." However, 52 Pa. Code § 62.2 also defines a "low-income customer" as "[a] residential utility customer whose gross household income is at or below 150% of the Federal poverty guidelines. Gross household income does not include the value of food stamps or other noncash income."[2]

Q. How many confirmed low-income customers does UGI Gas have?

A. As of November 30, 2025, the Company had 68,867 confirmed low-income customers. This figure represents customers who have self-certified their income, participated in the

[2] https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter62/s62.2.html&d=reduce

Company's CAP, Operation Share, or LIURP, where income was verified to be at or below 150% FPIG, as well as those customers who have received LIHEAP in the prior 12 months. Of the 68,867 Confirmed Low Income customers referenced above, UGI Gas has 38,499 customers who have gone through the Company's income verification process, have been verified at or below 150% FPIG, and are eligible to participate in a Universal Service Program.

Regarding estimated low-income customers at or below 150% FPIG, as part of the 2026-2030 USECP filing supplemental data request[3] from the PUC, the Company reported 143,404 estimated low-income customers. This figure was developed in accordance with the PUC's Bureau of Consumer Services specified methodology, which derived the estimated number of low income customers by calculating the number of UGI Gas customers in each county of its service territory multiplied by the 2019-2023 American Community Survey 5 Year Estimates census data provided by the Bureau of Consumer Services for that county. However, this calculation methodology may overstate the estimated low-income customer counts due to the census percentages of low-income customers by county which does not necessarily correlate to UGI Gas' customer demographics. By comparison, the Company's Low Income Customer Assessment and Outreach Pilot[4] undertaken with Experian, identified an estimated low-income population of 98,785 customers at or below 150% FPIG in the fall of 2023. The Experian estimate uses actual demographic income data of UGI customers and identifies significantly less customers, at only 68% of the estimated low income customer count of 143,404.

[3] August 25, 2025, response at Docket No. M-2025-3054362
[4] UGI Gas 2022 Base Rate Case settlement paragraph 46(a).

Therefore, UGI Gas's estimated low-income customer counts based on census and published in the USR should be considered an over estimation and referenced with caution.

V. WNA COMMUNICATIONS REVISIONS

Q. Has the Company provided revisions to its communication materials as required in its 2025 Gas Rate Case Settlement?

A. Yes. Consistent with the Settlement requirements, the Company shared draft materials with the required parties, including updates to the Weather Normalization webpage on its public facing website and a new customer letter. The customer letter provides an individualized explanation of charges or credits for a specific billing month. As specified in the 2025 Settlement, the Company solicited feedback from interested USAC members and the statutory parties. All edits were consolidated and distributed, with suggestions either incorporated into the materials or feedback provided explaining why they were not included. A final meeting was held with the statutory parties to address any concerns regarding feedback. Approximately twenty website updates were completed in December 2025, including creation of a new FAQ page, and seven revisions were made to the customer letter which will be available in fiscal year 2026.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT BJM-1

Brian J. Meilinger
Director – Customer Programs & Public Relations

Work Experience

UGI Utilities, Inc.

2025 – Present	Director – Customer Programs & Public Relations
2021 – 2025	Sr. Manager – Customer Programs & Community Relations
2015 – 2021	Manager – Energy Efficiency & Conservation Programs
2012 – 2015	Sr. Analyst – Financial Planning & Analysis

Previous Testimony

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2024-3052716

Education

Master of Business Administration in Finance - Saint Joseph's University, Philadelphia, PA
Bachelor of Arts in Economics & Business Administration - Ursinus College, Collegeville, PA

BOOK V

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT A – REVENUE REQUIREMENT - FULLY PROJECTED
UGI GAS EXHIBIT A – REVENUE REQUIREMENT - FUTURE
UGI GAS EXHIBIT A – REVENUE REQUIREMENT– HISTORIC
UGI GAS EXHIBIT B – RATE OF RETURN
UGI GAS EXHIBIT E – PROOF OF REVENUE

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI GAS

EXHIBIT A

FULLY PROJECTED

Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)
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Fully Projected Future Period - 12 Months Ended September 30, 2027

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UGI Utilities, Inc. - Gas Division | **Schedule A-1**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2027 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 6,676,559		$ 6,676,559
2	Accumulated Depreciation		C-3	(1,736,046)		(1,736,046)
3	Net Plant in service	L 1 + L 2		4,940,513	-	4,940,513
4	Working Capital		C-4	66,523		66,523
5	Gas Inventory		C-5	23,662		23,662
6	Accumulated Deferred Income Taxes		C-6	(716,793)		(716,793)
7	Customer Deposits		C-7	(23,197)		(23,197)
8	Materials & Supplies		C-8	28,644		28,644
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 4,319,352	$ -	$ 4,319,352
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 815,579	$ 99,368	$ 914,947
11	Gas Cost Revenue		D-5	404,972		404,972
12	Other Operating Revenues		D-5	14,131		14,131
13	Total Revenues	Sum L 10 to L 12		1,234,682	99,368	1,334,050
14	Operating Expenses		D-1	(901,710)	(1,712)	(903,422)
15	OIBIT	L 13 + L 14		332,973	97,656	430,628
16	Pro Forma Income Tax at Present Rates		D-33	(50,156)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(26,286)	(76,442)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 282,817	$ 71,369	$ 354,186
19	RATE OF RETURN	L 18 / L 9		6.5477%		8.2000%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		6.5477%		
21	Rate of Return Required		B-7	8.2000%		
22	Change in ROR	L 21 - L 20		1.6523%		
23	Change in Operating Income	L 22 * L 9		$ 71,370		
24	Gross Revenue Conversion Factor		D-35	1.392298		
25	Change in Revenues	L 23 * L 24		$ 99,368		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, Col 3			12.18%	
27	Percent Increase -- Total Revenues	L 25 / L 13, Col 3			8.05%	

UGI Utilities, Inc. - Gas Division | **Schedule B-1**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 2**
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-27
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 6,218,576
2	Other Utility Plant	
3	Total Plant In Service	6,218,576
4	Construction Work In Progress (107)	123,341
5	Total Utility Plant	6,341,917
6	Accumulated Provision for Depreciation - Gas (108)	(1,618,836)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	
9	Net Utility Plant	4,905,226
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	714
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,168
13	Other Investments (124)	15
14	Total Other Property and Investments	1,897
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	15,093
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	108,551
18	Other Accounts Receivable (143)	13,706
19	Accum Provision for Uncollectible (144)	(14,810)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	3,596
22	Plant Materials & Operating Supplies (154)	23,722
23	Stores Expense - Undistributed (163)	2,470
24	Gas Stored - Current (164.1)	53,036
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	20,395
27	Accrued Utility Revenues (173)	24,907
28	Miscellaneous Current & Accrued Assets (174)	148
29	Derivative Instrument Assets (175)	2,244
30	Total Current and Accrued Assets	253,058
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	7,882
32	Other Regulatory Assets (182.3)	484,191
33	Other Preliminary Survey & Investigation Charges (183.2)	48
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	26,845
36	Def. Losses from Disposition of Utility Plt. (187)	-
37	Unamortized Loss on Reacquired Debt (189)	-
38	Accumulated Deferred Income Taxes (190)	-
39	O/U Collected Gas (191.4, 191.41)	-
40	Total Deferred Debits	518,966
41	TOTAL ASSETS AND OTHER DEBITS	$ 5,679,146

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-27
	PROPRIETARY CAPITAL	
42	Common Stock Issued (201)	$ 53,926
43	Preferred Stock Issued (204)	-
44	Premium on Capital Stock (207)	559,361
45	Capital Stock Expense (214)	-
46	Retained Earnings (215, 215.2, 216)	1,332,939
47	Accum Other Comprehensive Income (219)	(12,094)
48	Total Proprietary Capital	1,934,133
	LONG TERM DEBT	
49	Bonds (221)	-
50	Advances from Associated Companies (223)	-
51	Other Long-Term Debt (224)	2,040,706
52	Unamortized Premium on LTD (225)	-
53	Unamortized Discount on LTD (226)	-
54	Total Long-term Debt	2,040,706
	OTHER NON-CURRENT LIABILITIES	
55	Obligations under Capital Leases (227)	163
56	Accum. Prov for Injuries & Damages (228.2)	1,890
57	Accum. Prov for Pensions & Benefits (228.3)	0
58	Accum. Miscellaneous Operating Prov (228.4)	52,272
59	Asset Retirement Obligation (230)	111
60	Total Non-Current Liabilities	54,437
	CURRENT & ACCRUED LIABILITIES	
61	Notes Payable (231)	254,520
62	Accounts Payable (232)	97,314
63	Notes Payable to Assoc. Companies (233)	-
64	Accounts Payable to Assoc. Cos (234)	2,285
65	Customer Deposits (235)	23,852
66	Taxes Accrued (236)	(10,612)
67	Interest Accrued (237)	23,710
68	Tax Collections Payable (241)	755
69	Misc Current & Accrued Liabilities (242)	83,538
70	Obligations Under Capital Leases (243)	504
71	Derivative Instrument Liabilities (244)	6,278
72	Total Current & Accrued Liabilities	482,145
	OTHER DEFERRED CREDITS	
73	Customer Advances for Construction (252)	-
74	Other Deferred Credits (253)	22,505
75	Other Regulatory Liabilities (254)	270,522
76	Deferred ITC (255)	791
77	Accumulated Deferred Income Taxes (282)	821,359
78	Accumulated Deferred Income Taxes (283)	52,548
79	Total Other Deferred Credits	1,167,725
80	TOTAL LIABILITIES & OTHER CREDITS	$ 5,679,146

UGI Utilities, Inc. - Gas Division | **Schedule B-2**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-27	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 1,270,313	B-3
2	Other Operating Revenues	13,419	B-3
3	Total Revenues	1,283,732	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	734,438	B-4
5	Depreciation & Amortization Expense	164,574	D-2
6	Taxes Other Than Income Taxes	14,299	B-5
7	Total Operating Expenses	913,311	
8	Operating Income Before Income Taxes (OIBIT)	370,420	
	Income Taxes:		
9	State	8,900	B-5
10	Federal	41,256	B-5
11	Total Income Taxes	50,156	
12	**Net Utility Operating Income**	$ 320,264	

UGI Utilities, Inc. - Gas Division | **Schedule B-3**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Statement of Operating Revenues

Line No	Description	[1] Budget TYE 9-30-27
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 815,696
2	Comm & Ind (N/NT) (481)	295,972
3	Comm & Ind (DS) (489)	36,322
4	Lg Transport/Other (489)	99,453
5	Interruptible (489)	22,870
6	Sub-Total Gas Operating Revenues	1,270,313
	Other Operating Revenues	
7	Forfeited Discounts (487)	6,337
8	Miscellaneous Service Revenues (488)	3,178
9	Rent from Gas Properties (493)	2,292
10	Other Revenues (495)	1,612
11	Sub-Total Other Operating Revenues	13,419
12	**Total Operating Revenues**	$ 1,283,732

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	-
3	Total Gas Raw Materials Expenses		-
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	530,074
16	Other Gas Purchases	805.0	5
17	Purchases Gas Cost Adjustments	805.1	(81,826)
18	Gas Withdrawn from Storage-Debit	808.1	47,230
19	Purchased Gas Expenses	807.0	-
20	Gas Used for Other Utility Operations-Credit	812.0	2,169
21	Gas Delivered to Storage-Credit	808.2	(62,675)
22	Other Gas Supply Expenses	813.0	(5,256)
23	Gas Supply Operation Expenses		429,721
	Underground Storage Expense - Operation		
24	Operation Supervision and Engineering	814	-
25	Maps and Records	815	-
26	Wells Expenses	816	-
27	Lines Expenses	817	-
28	Measuring and Regulating Station Expenses	820	-
29	Purification Expenses	821	-
30	Gas Losses	823	-
31	Other Expenses	824	-
32	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
33	Maintenance Supervision and Engineering	830	-
34	Maintenance of Structures and Improvements	831	-
35	Maintenance of Reservoirs and Wells	832	-
36	Maintenance of Lines	833	-
37	Maintenance of Measuring & Regulating Station Equip.	835	-
38	Total Underground Maintenance Expenses		-

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Transmission Expense - Operations		
39	Operating Supervision and Engineering	850	-
40	System Control and Load Dispatching	851	-
41	Communication System Expenses	852	-
42	Mains Expenses	856	-
43	Measuring and Regulating Station Expenses	857	-
44	Other Expenses	859	-
45	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
46	Maintenance Supervision and Engineering	861	-
47	Maintenance of Structures and Improvements	862	-
48	Maintenance of Mains	863	-
49	Maintenance of Measuring and Regulating Station Equip.	865	-
50	Maintenance of Communication Equipment	866	-
51	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
52	Operation Supervision and Engineering	870	6,264
53	Distribution Load Dispatching	871	3,424
54	Compressor Station Fuel and Power (Major Only)	873	-
55	Mains and Services Expenses	874	34,590
56	Measuring and Regulating Station Expenses-General	875	2,194
57	Measuring and Regulating Station Expenses-Industrial	876	21
58	Measuring and Regulating Station Expenses-City Gate	877	456
59	Meter and House Regulator Expenses	878	3,661
60	Customer Installations Expenses	879	3,328
61	Other Expenses	880	7,219
62	Rents	881	651
63	Total Distribution Operation Expenses		61,808
	Distribution Expense - Maintenance		
64	Maintenance Supervision and Engineering	885	2,325
65	Maintenance of Structures and Improvements	886	-
66	Maintenance of Mains	887	21,659
67	Maintenance of Compressor Station Equipment	888	-
68	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	2,353
69	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	3,991
70	Maintenance of Measuring & Reg. Station Equip.-City G	891	105
71	Maintenance of Services	892	677
72	Maintenance of Meters & House Regulators	893	40
73	Maintenance of Other Equipment	894	592
74	Construction & Maintenance	895	-
75	Total Distribution Maintenance Expenses		31,741
	Customer Accounts Expense - Operations		
76	Supervision	901	873
77	Meter Reading Expenses	902	2,940
78	Customer Records & Collection Expenses	903	58,278
79	Uncollectable Accounts	904	20,671
80	Miscellaneous Customer Accounts Expenses	905	70
81	Total Administrative & General		82,832

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Customer Service & Information Expense		
82	Supervision	907	89
83	Customer Assistance Expenses	908	1,099
84	Informational & Instructional Advertising Expenses	909	1,358
85	Miscellaneous Customer Service & Informational Exp.	910	12,447
86	Total Cust. Service & Inform. Operations Exp		14,993
	Sales Expense		
87	Supervision	911	-
88	Demonstrating and Selling Expenses	912	758
89	Advertising Expenses	913	526
90	Miscellaneous Sales Expenses	916	-
91	Total Operation Sales Expenses		1,283
	Administrative & General - Operations		
92	Administrative and General Salaries	920.0	36,333
93	Office Supplies and Expenses	921.0	19,009
94	Outside Service Employed	923.0	20,445
95	Property Insurance	924.0	361
96	Injuries and Damages	925.0	11,158
97	Employee Pensions and Benefits	926.0	15,367
98	Regulatory Commission Expenses	928.0	2,296
99	General Advertising Expenses	930.1	171
100	Miscellaneous General Expenses	930.2	1,616
101	Rents	931.0	77
102	Total A & G Operation Expenses		106,833
	Administrative & General - Maintenance		
103	A&G Maintenance of General Plant	932	5,228
104	A&G Maintenance of General Plant	935	-
105	Total A & G Maintenance Expenses		5,228
106	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 734,438
107	Total Gas Operation Expenses		697,470
108	Total Gas Maintenance Expense		36,969
109	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 734,438

UGI Utilities, Inc. - Gas Division | **Schedule B-5**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-27
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 1,420
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	1,250
4	PUC Assessment	D-31	5,131
5	Subtotal		7,801
	Payroll Taxes		
6	FICA	D-31	6,175
7	SUTA	D-31	317
8	FUTA	D-31	6
9	Other		-
10	Subtotal		6,498
11	Total Taxes Other Than Income Taxes		$ 14,299
	Income Taxes		
12	State		$ 8,900
13	Federal		41,256
14	Total Income Taxes		$ 50,156

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4]*[5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	0.94%	6.56%	0.06%
2	6.133%	10/14/2004	10/15/2034	20,000	0.94%	6.19%	0.06%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	4.70%	6.32%	0.30%
4	4.980%	3/26/2014	3/26/2044	175,000	8.22%	5.00%	0.41%
5	4.120%	9/30/2016	9/30/2046	200,000	9.39%	5.01%	0.47%
6	4.120%	10/31/2016	10/31/2046	100,000	4.70%	4.28%	0.20%
7	4.550%	2/1/2019	2/1/2049	150,000	7.05%	4.58%	0.32%
8	3.120%	3/19/2020	4/16/2050	150,000	7.05%	3.15%	0.22%
9	4.750%	7/15/2022	7/15/2032	90,000	4.23%	4.82%	0.20%
10	4.990%	9/15/2022	9/15/2052	85,000	3.99%	5.03%	0.20%
11	6.100%	11/30/2023	11/30/2033	150,000	7.05%	6.17%	0.43%
12	6.400%	11/30/2023	11/30/2053	75,000	3.52%	6.43%	0.23%
13	6.020%	11/30/2023	11/30/2030	25,000	1.17%	6.11%	0.07%
14	5.240%	11/14/2024	11/30/2029	50,000	2.35%	5.38%	0.13%
15	5.520%	11/14/2024	11/30/2034	125,000	5.87%	5.60%	0.33%
16	5.100%	11/14/2025	11/14/2035	150,000	7.05%	5.16%	0.36%
17	5.680%	11/14/2025	11/14/2035	125,000	5.87%	5.75%	0.34%
18	5.600%	1/31/2026	6/30/2036	75,000	3.52%	5.67%	0.20%
19	5.693%	11/30/2026	11/30/2036	200,000	9.39%	5.78%	0.54%
Term Loan							
20	3.098%	10/31/2026	10/31/2036	64,063	3.01%	3.17%	0.10%
21	Total Long-Term Debt			$ 2,129,063	100.00%		5.17%
22	Total Long-Term Debt			$ 2,129,063	100.00%	5.17%	5.17%
23	Total Short-Term Debt				0.00%		0.00%
24	TOTAL			$ 2,129,063	100.00%		
25	Weighted Cost of Debt						5.17%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-7
Witness: D. W. D'Ascendis

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	45.75%	5.17%	B-6	2.37%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	54.25%	10.75%		5.83%
4	Total	100.00%			8.20%

UGI Utilities, Inc. - Gas Division | **Schedule C-1**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Measure of Value

Line #	Description	[1] Reference Schedule	[2] # of Pages	[3] Pro Forma Test Year Ended September 30, 2027 At Present Rates	[4] Adjustments	[5] Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 6,676,559		$ 6,676,559
2	Accumulated Depreciation	C-3	11	(1,736,046)		(1,736,046)
3	Net Plant in service			4,940,513	-	4,940,513
4	Working Capital	C-4	9	66,523		66,523
5	Gas Inventory	C-5	1	23,662		23,662
6	Accumulated Deferred Income Taxes	C-6	1	(716,793)		(716,793)
7	Customer Deposits	C-7	1	(23,197)		(23,197)
8	Materials & Supplies	C-8	1	28,644		28,644
9	TOTAL MEASURE OF VALUE			$ 4,319,352	$ -	$ 4,319,352

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,468
34	Measuring & Regulating Station Equipment	369	6,173
35	Communication Equipment	370	3,505
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,575
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,638
39	Structures & Improvements	375	7,923
40	Mains	376	3,190,354
41	Measuring & Regulating Station Equipment	378	229,058
42	Measuring & Regulating Station Equipment	379	81,780
43	Services	380	1,937,404
44	Meters	381	219,403
45	Meter Installations	382	153,632
46	House Regulators	383	10,274
47	House Regulatory Installations	384	17,829
48	Industrial Measuring & Reg. Station Equipment	385	42,671
49	Other Property	386	1,274
50	Other Equipment	387	6,799
51	TOTAL DISTRIBUTION		5,910,038
	GENERAL PLANT		
52	Land & Land Rights	389	14,128
53	Structures & Improvements	390	240,055
54	Office Furniture & Equipment	391	308,260
55	Transportation Equipment	392	87,535
56	Stores Equipment	393	16
57	Tools & Garage Equipment	394	46,259
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	13,798
60	Communication Equipment	397	2,364
61	Miscellaneous Equipment	398	2,320
62	Other Tangible Property	399	-
63	TOTAL GENERAL		715,173
64	Total Plant		$ 6,676,559

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/27 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	-	-	-
4	Transmission Plant	Sch C-2, Page 5	50,575	-	50,575
5	Distribution Plant	Sch C-2, Page 5	5,910,038	-	5,910,038
6	General Plant	Sch C-2, Page 5	715,173	-	715,173
7	Other Plant		-	-	-
8	Total Utility Plant		$ 6,676,559	$ -	$ 6,676,559

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ 290	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	194	-	194
3	Miscellaneous Intangible Plant	303	290	290	-	290
4	TOTAL INTANGIBLE		774	774	-	774
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	-	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-	-

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	47	47	-	47
31	Rights of Way	365.2	868	868	-	868
32	Structures & Improvements	366	162	162	-	162
33	Mains	367	39,468	39,468	-	39,468
34	Measuring & Regulating Station Equipment	369	6,173	6,173	-	6,173
35	Communication Equipment	370	3,505	3,505	-	3,505
36	Other Equipment	371	351	351	-	351
37	TOTAL TRANSMISSION		50,575	50,575	-	50,575
DISTRIBUTION PLANT						
38	Land & Land Rights	374	11,638	11,638	-	11,638
39	Structures & Improvements	375	7,923	7,923	-	7,923
40	Mains	376	2,956,090	3,190,354	-	3,190,354
41	Measuring & Regulating Station Equipment	378	191,451	229,058	-	229,058
42	Measuring & Regulating Station Equipment	379	81,780	81,780	-	81,780
43	Services	380	1,799,933	1,937,404	-	1,937,404
44	Meters	381	205,771	219,403	-	219,403
45	Meter Installations	382	147,331	153,632	-	153,632
46	House Regulators	383	10,274	10,274	-	10,274
47	House Regulatory Installations	384	17,829	17,829	-	17,829
48	Industrial Measuring & Reg. Station Equipment	385	41,443	42,671	-	42,671
49	Other Property	386	1,274	1,274	-	1,274
50	Other Equipment	387	6,799	6,799	-	6,799
51	TOTAL DISTRIBUTION		5,479,536	5,910,038	-	5,910,038
GENERAL PLANT						
52	Land & Land Rights	389	14,128	14,128	-	14,128
53	Structures & Improvements	390	224,104	240,055	-	240,055
54	Office Furniture & Equipment	391	298,038	308,260	-	308,260
55	Transportation Equipment	392	77,031	87,535	-	87,535
56	Stores Equipment	393	16	16	-	16
57	Tools & Garage Equipment	394	45,411	46,259	-	46,259
58	Laboratory Equipment	395	438	438	-	438
59	Power Operated Equipment	396	13,798	13,798	-	13,798
60	Communication Equipment	397	3,095	2,364	-	2,364
61	Miscellaneous Equipment	398	1,937	2,320	-	2,320
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		677,996	715,173	-	715,173
64	Total Plant		$ 6,208,881	$ 6,676,559	$ -	$ 6,676,559

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2026	[3] Year ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2026	[3] Year ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	759	-
40	Mains	376	210,564	241,883
41	Measuring & Regulating Station Equipment	378	27,444	37,902
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	134,149	159,733
44	Meters	381	15,547	16,346
45	Meter Installations	382	6,296	7,321
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	1,002	1,237
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		395,762	464,422
GENERAL PLANT				
52	Land & Land Rights	389	606	-
53	Structures & Improvements	390	16,683	16,746
54	Office Furniture & Equipment	391	43,926	12,273
55	Transportation Equipment	392	11,248	11,672
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	1,834	2,374
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	524	507
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		74,820	43,572
64	Total Plant		$ 470,582	$ 507,994

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	
39	Structures & Improvements	375	(17)	
40	Mains	376	(6,651)	(7,619)
41	Measuring & Regulating Station Equipment	378	(214)	(295)
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	(18,697)	(22,263)
44	Meters	381	(2,615)	(2,714)
45	Meter Installations	382	(878)	(1,020)
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	(8)	(10)
49	Other Property	386	-	
50	Other Equipment	387	-	
51	TOTAL DISTRIBUTION		(29,079)	(33,921)
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	(345)	(795)
54	Office Furniture & Equipment	391	(27,513)	(2,051)
55	Transportation Equipment	392	(1,125)	(1,167)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	(1,231)	(1,526)
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	(731)
61	Miscellaneous Equipment	398	(97)	(124)
62	Other Tangible Property	399	(16)	-
63	TOTAL GENERAL		(30,327)	(6,395)
64	Total Plant		$ (59,406)	$ (40,316)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	594
32	Structures & Improvements	366	157
33	Mains	367	23,932
34	Measuring & Regulating Station Equipment	369	4,437
35	Communication Equipment	370	2,631
36	Other Equipment	371	312
37	TOTAL TRANSMISSION		32,063
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,594
39	Structures & Improvements	375	3,846
40	Mains	376	644,412
41	Measuring & Regulating Station Equipment	378	51,380
42	Measuring & Regulating Station Equipment	379	18,454
43	Services	380	508,598
44	Meters	381	91,740
45	Meter Installations	382	52,438
46	House Regulators	383	6,278
47	House Regulatory Installations	384	10,128
48	Industrial Measuring & Reg. Station Equipment	385	22,284
49	Other Property	386	729
50	Other Equipment	387	4,894
51	TOTAL DISTRIBUTION		1,416,775
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	70,116
54	Office Furniture & Equipment	391	149,964
55	Transportation Equipment	392	39,498
56	Stores Equipment	393	9
57	Tools & Garage Equipment	394	18,442
58	Laboratory Equipment	395	223
59	Power Operated Equipment	396	6,980
60	Communication Equipment	397	752
61	Miscellaneous Equipment	398	1,223
62	Other Tangible Property	399	
63	TOTAL GENERAL		287,208
64	Total Plant		$ 1,736,046

Summary of Accumulated Depreciation

Line #	Description	[1] Factor Or Reference	[2] Test Year Ended September 30, 2027 Amount	[3] Pro Forma Adjustment	[4] Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	$ -	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	-	-	-
4	Transmission Plant	Sch C-3, Pg 5	32,063	-	32,063
5	Distribution Plant	Sch C-3, Pg 5	1,416,775	-	1,416,775
6	General Plant	Sch C-3, Pg 5	287,208	-	287,208
7	Other Plant		-	-	-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,736,046	$ -	$ 1,736,046

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ -	$ -	-	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	-	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-	-

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	-	-	-	-
31	Rights of Way	365.2	583	594	-	594
32	Structures & Improvements	366	157	157	-	157
33	Mains	367	23,526	23,932	-	23,932
34	Measuring & Regulating Station Equipment	369	4,348	4,437	-	4,437
35	Communication Equipment	370	2,549	2,631	-	2,631
36	Other Equipment	371	306	312	-	312
37	TOTAL TRANSMISSION		31,470	32,063	-	32,063
DISTRIBUTION PLANT						
38	Land & Land Rights	374	1,551	1,594	-	1,594
39	Structures & Improvements	375	3,694	3,846	-	3,846
40	Mains	376	603,006	644,412	-	644,412
41	Measuring & Regulating Station Equipment	378	46,205	51,380	-	51,380
42	Measuring & Regulating Station Equipment	379	16,033	18,454	-	18,454
43	Services	380	485,016	508,598	-	508,598
44	Meters	381	86,841	91,740	-	91,740
45	Meter Installations	382	50,079	52,438	-	52,438
46	House Regulators	383	5,133	6,278	-	6,278
47	House Regulatory Installations	384	9,801	10,128	-	10,128
48	Industrial Measuring & Reg. Station Equipment	385	21,131	22,284	-	22,284
49	Other Property	386	701	729	-	729
50	Other Equipment	387	4,802	4,894	-	4,894
51	TOTAL DISTRIBUTION		1,333,994	1,416,775	-	1,416,775
GENERAL PLANT						
52	Land & Land Rights	389	-	-	-	-
53	Structures & Improvements	390	62,353	70,116	-	70,116
54	Office Furniture & Equipment	391	125,461	149,964	-	149,964
55	Transportation Equipment	392	33,930	39,498	-	39,498
56	Stores Equipment	393	8	9	-	9
57	Tools & Garage Equipment	394	17,652	18,442	-	18,442
58	Laboratory Equipment	395	201	223	-	223
59	Power Operated Equipment	396	6,099	6,980	-	6,980
60	Communication Equipment	397	1,216	752	-	752
61	Miscellaneous Equipment	398	1,208	1,223	-	1,223
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		248,128	287,208	-	287,208
64	Total Plant		$ 1,613,591	$ 1,736,046	$ -	$ 1,736,046

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330		
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305		
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	7	-
40	Mains	376	1,939	2,218
41	Measuring & Regulating Station Equipment	378	53	74
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	7,271	8,658
44	Meters	381	-	-
45	Meter Installations	382	341	397
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	(326)	(403)
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		9,287	10,944
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	31	72
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	-	-
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		31	72
64	Total Plant		$ 9,318	$ 11,016

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	3	3
34	Measuring & Regulating Station Equipment	369	1	0
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		4	3
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	4	4
40	Mains	376	2,586	2,600
41	Measuring & Regulating Station Equipment	378	203	162
42	Measuring & Regulating Station Equipment	379	85	65
43	Services	380	5,360	6,182
44	Meters	381	38	38
45	Meter Installations	382	157	203
46	House Regulators	383	872	872
47	House Regulatory Installations	384	1	1
48	Industrial Measuring & Reg. Station Equipment	385	(48)	(128)
49	Other Property	386	0	0
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		9,259	9,999
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	138	152
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(789)	(502)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	4	0
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	3	3
61	Miscellaneous Equipment	398	78	48
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(566)	(300)
64	Total Plant		$ 8,698	$ 9,703

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	-	-
41	Measuring & Regulating Station Equipment	378	-	-
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	-	-
44	Meters	381	-	-
45	Meter Installations	382	-	-
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		-	-
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	-
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(112)	(117)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(112)	(117)
64	Total Plant		$ (112)	$ (117)

Working Capital

Line No	Description	[1] Fully Projected TYE 9-30-27	[2] Reference
1	Working Capital for O & M Expense	$ 57,012	C-4, Page 2
2	Interest Payments	(9,459)	C-4, Page 7
3	Tax Payment Lag Calculations	4,570	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 66,523	

Summary of Working Capital

Line #	Description	Reference	[1] Test Year Expenses	[2] Factor	[3] Number of (Lead) / Lag Days [2] * [3]	[4] Totals	[5]
WORKING CAPITAL REQUIREMENT							
1	REVENUE LAG DAYS	Page 3					57.46
2	EXPENSE LAG DAYS	Page 4					
3	Payroll	Sch D-7	$ 82,522	12.00	$ 990,258		
4	Purchased Gas Costs	Sch D-6	404,972	26.09	10,563,938		
5	Other Expenses	L 18 - L 3 to L 4	208,108	36.55	7,606,337		
6	Total	Sum (L 3 to L 5)	$ 695,601		$ 19,160,534		
7	O & M Expense Lag Days	L6, C 4 / C 2					27.55
8	Net (Lead) Lag Days	L 1 - L 7					29.91
9	Operating Expenses Per Day	L 6, C 2 / 365				$	1,906
10	Working Capital for O & M Expense	L 8 * L 9				$	57,012
11	Interest Payments	Page 7					(9,459)
12	Tax Payment Lag Calculations	Page 8					4,570
13	Prepaid Expenses	Page 9					14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$	66,523
15	Pro Forma O & M Expense		$ 715,943				
	Less:						
16	Uncollectible Expense		20,342				
17	Sub-Total		20,342				
18	Pro Forma Cash O&M Expense		$ 695,601				

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]	[5] Days Lag 365 / [4]
1	Annual Number of Days					365
2	September, 2024		$59,595			
3	October		$54,962	$49,570		
4	November		$65,027	$66,062		
5	December, 2024		$115,180	$130,278		
6	January, 2025		$180,732	$200,306		
7	February		$209,136	$183,549		
8	March		$200,671	$160,286		
9	April		$178,319	$106,926		
10	May		$148,644	$67,400		
11	June		$131,419	$49,633		
12	July		$110,237	$42,524		
13	August		$88,906	$37,847		
14	September, 2025		$72,798	$41,343		
15	Total	Sum L 2 to L 14	$1,615,626			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$124,279			
18	Total Sales for Year	Sum L 2 to L 14		$ 1,135,724		
19	Acct Rec Turnover Ratio	L 18 / L 17			9.14	
20	Collection Lag Day Factor	L 1 / L 19				39.93
21	Meter Read Lag Factor					2.32
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**57.46**

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 36,103	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	46,417	12.00		
3	Weighted for Union	L1, C2 * C3			$ 433,236	
4	Weighted for Other	L2, C2 * C3			557,008	
5	Payroll Lag	L 3 + L 4	$ 82,520		$ 990,244	
6	Payroll Lag Days	L5, C4 / C2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 505,975		$ 13,198,681	
8	Gas Cost Lag Days	L7, C4 / C2				26.09
OTHER O & M EXPENSES						
9	October-2024	Page 5	$ 12,404		$ 323,056	
10	November-2024	Page 5	9,141		250,782	
11	December-2024	Page 5	10,855		287,049	
12	January-2025	Page 5	25,282		1,499,042	
13	February-2025	Page 5	15,794		514,617	
14	March-2025	Page 5	9,353		273,241	
15	April-2025	Page 5	12,385		289,995	
16	May-2025	Page 5	13,770		597,078	
17	June-2025	Page 5	14,096		499,028	
18	July-2025	Page 5	20,034		1,249,027	
19	August-2025	Page 5	13,203		391,825	
20	September-2025	Page 5	38,365		941,232	
21	TOTAL		$ 194,681		$ 7,115,972	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				36.55

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
October-2024					
1	Total Disbursements for Month	32,838	$ 62,746		
2	Total Disbursements for Expenses	3,838	$ 12,404	$ 323,056	26.04
November-2024					
3	Total Disbursements for Month	23,901	$ 38,794		
4	Total Disbursements for Expenses	3,565	$ 9,141	$ 250,782	27.43
December-2024					
5	Total Disbursements for Month	24,687	$ 38,022		
6	Total Disbursements for Expenses	4,006	$ 10,855	$ 287,049	26.44
January-2025					
7	Total Disbursements for Month	21,368	$ 50,983		
8	Total Disbursements for Expenses	3,947	$ 25,282	$ 1,499,042	59.29
February-2025					
9	Total Disbursements for Month	18,066	$ 32,989		
10	Total Disbursements for Expenses	3,439	$ 15,794	$ 514,617	32.58
March-2025					
11	Total Disbursements for Month	18,513	$ 27,337		
12	Total Disbursements for Expenses	3,735	$ 9,353	$ 273,241	29.21
April-2025					
13	Total Disbursements for Month	25,630	$ 41,058		
14	Total Disbursements for Expenses	4,257	$ 12,385	$ 289,995	23.41
May-2025					
15	Total Disbursements for Month	34,781	$ 47,440		
16	Total Disbursements for Expenses	4,049	$ 13,770	$ 597,078	43.36
June-2025					
17	Total Disbursements for Month	29,782	$ 46,699		
18	Total Disbursements for Expenses	4,127	$ 14,096	$ 499,028	35.40
July-2025					
19	Total Disbursements for Month	31,463	$ 57,790		
20	Total Disbursements for Expenses	4,523	$ 20,034	$ 1,249,027	62.35
August-2025					
21	Total Disbursements for Month	32,254	$ 46,003		
22	Total Disbursements for Expenses	4,224	$ 13,203	$ 391,825	29.68
September-2025					
23	Total Disbursements for Month	34,037	$ 80,893		
24	Total Disbursements for Expenses	3,958	$ 38,365	$ 941,232	24.53
25	Total Test Month Expense Disbursement	47,668	$ 194,681	$ 7,115,972	36.55

Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October-2024	37	$ 38,708	$ 521,883	13.48
2	November-2024	38	42,900	573,631	13.37
3	December-2024	42	61,187	1,434,065	23.44
4	January-2025	45	101,888	1,975,569	19.39
5	February-2025	42	73,452	1,791,212	24.39
6	March-2025	33	37,168	1,424,885	38.34
7	April-2025	35	39,413	1,421,523	36.07
8	May-2025	31	26,967	1,017,164	37.72
9	June-2025	32	22,772	833,747	36.61
10	July-2025	28	22,723	835,609	36.77
11	August-2025	27	20,780	750,436	36.11
12	September-2025	30	18,017	618,957	34.35
13	Total		$ 505,975	$ 13,198,681	
14	Purchase Gas Lag Days				26.09

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2027	Sch C-1			$ 4,319,352
2	Long-term Debt Ratio	Sch B-7			45.75%
3	Embedded Cost of Long-term Debt	Sch B-6			5.17%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 102,165
5	Daily Amount	L 4 / L 5 [2]	365		$ 280
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		57.46	
8	Interest Payment lag days	L 7 - L 6			(33.8)
9	Total Interest for Working Capital	L 5 * L 8			$ (9,459)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount 365
1	**FEDERAL INCOME TAX**				$ 60,228						
2	First Payment	01/15/27	04/01/27	76.00	$ 15,057	1,144,334					
3	Second Payment	03/15/27	04/01/27	17.00	15,057	255,969					
4	Third Payment	06/15/27	04/01/27	(75.00)	15,057	(1,129,276)					
5	Fourth Payment	09/15/27	04/01/27	(167.00)	15,057	(2,514,522)					
6	Total				$ 60,228	$ (2,243,496)	(37.25)	(57.46)	20.21	$ 1,217,029	$ 3,334
7	**STATE INCOME TAX**				$ 16,214						
8	First Payment	12/15/26	04/01/27	107.00	$ 4,053	433,724					
9	Second Payment	03/15/27	04/01/27	17.00	4,053	68,909					
10	Third Payment	06/15/27	04/01/27	(75.00)	4,053	(304,012)					
11	Fourth Payment	09/15/27	04/01/27	(167.00)	4,053	(676,933)					
12	Total				$ 16,214	(478,312)	(29.50)	(57.46)	27.96	$ 453,294	$ 1,242
13	**PA PROPERTY TAX**				$ 1,250						
14	First Payment	04/30/27	04/01/27	(29.00)	$ 625	(18,125)					
15	Second Payment	08/31/27	04/01/27	(152.00)	625	(95,000)					
16	Total				$ 1,250	(113,125)	(90.50)	(57.46)	(33.04)	$ (41,304)	$ (113)
17	**PURTA**				$ 1,420						
18	Payment	05/01/27	04/01/27	(30.00)	$ 1,420	(42,600)	(30.00)	(57.46)	27.46	$ 38,989	$ 107
19	Total Working Capital For Other Taxes										$ 4,570

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Miscellaneous	[6] Subscriptions	[7] Postage	[8] Rent	[9] Maintenance & Services
1	September, 2024		17,897	7,651	3,412	385	108	2	-	6,338
2	October		18,551	6,660	3,033	400	280	3	-	8,174
3	November		17,249	6,247	2,654	400	199	3	-	7,746
4	December, 2024		17,645	5,421	2,275	326	118	0	-	9,504
5	January, 2025		16,934	4,526	1,896	571	372	0	-	9,569
6	February		14,804	3,722	1,517	469	545	0	-	8,551
7	March		13,077	2,826	1,137	429	575	2	-	8,108
8	April		10,792	1,968	758	417	648	(3)	-	7,004
9	May		8,657	1,070	379	350	539	4	-	6,315
10	June		7,338	172	-	283	433	5	-	6,445
11	July		9,081	299	-	224	561	2	-	7,996
12	August		16,621	8,732	-	233	399	4	-	7,253
13	September, 2025		18,558	7,869	3,413	180	290	2	-	6,804
14	TOTAL		$ 187,204	$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
17	Monthly Average	13		$ 4,397	$ 1,575	$ 359	$ 390	$ 2	$ -	$ 7,677
18	Rate Case Amount		$ 14,400							

UGI Utilities, Inc. - Gas Division | **Schedule C-5**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2024	$27,677
2	October	32,669
3	November	32,041
4	December, 2024	25,192
5	January, 2025	15,334
6	February	8,991
7	March	3,692
8	April	11,088
9	May	17,289
10	June	24,134
11	July	30,732
12	August	36,859
13	September, 2025	41,904
14	Total	$ 307,601
15	Number of Months	13
16	Average Monthly Balance	$ 23,662

UGI Utilities, Inc. - Gas Division | **Schedule C-6**
Before the Pennsylvania Public Utility Commission | **Witness: D. T. Espigh**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (724,029)	
2	Sub-total		(724,029)
3	ADIT on CIAC	39,331	
4	Sub-total		39,331
5	Federal ADIT		(684,698)
6	State Repair Regulatory Liability	(48,917)	(48,917)
7	CIAC Tax Gross-Up Regulatory Liability	(422)	(422)
8	Pro-Rata Adjustment	17,243	17,243
9	Balance At September 30, 2027		$ (716,793)

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2024	$ 20,721
2	October	$ 21,053
3	November	$ 21,369
4	December, 2024	$ 21,641
5	January, 2025	$ 22,111
6	February	$ 22,868
7	March	$ 24,005
8	April	$ 24,716
9	May	$ 24,801
10	June	$ 24,688
11	July	$ 24,591
12	August	$ 24,522
13	September, 2025	$ 24,475
14	Total	$ 301,560
15	Number of Months	13
16	Average Monthly Balance	$ 23,197

UGI Utilities, Inc. - Gas Division | **Schedule C-8**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2024	$ 30,420
2	October	30,020
3	November	29,626
4	December, 2024	29,997
5	January, 2025	29,829
6	February	30,374
7	March	29,642
8	April	29,028
9	May	28,754
10	June	27,778
11	July	26,665
12	August	25,527
13	September, 2025	24,707
14	Total	$ 372,366
15	Number of Months	13
16	Average Monthly Balance	$ 28,644

UGI Utilities, Inc. - Gas Division | **Schedule D-1**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Pro Forma Test Year Rate Increase	[3] Pro Forma Test Year At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 772,828	$ -	$ 772,828
2	Gas Supply & Cost Adjustment Revenue		447,723	-	447,723
3	Other Revenues		14,131	-	14,131
4	Revenue Increase			99,368	99,368
5	Total operating revenues		1,234,682	99,368	1,334,050
	OPERATING EXPENSES				
6	Manufactured Gas		-	-	-
7	Gas Supply Production		404,972	-	404,972
8	Transmission		-		
9	Distribution		94,027	-	94,027
10	Customer Accounts		62,571	-	62,571
11	Uncollectible Expense	1.723%	20,342	1,712	22,054
12	Customer Information & Services		14,666	-	14,666
13	Sales		1,292	-	1,292
14	Administrative & General		118,072	-	118,072
15	Depreciation & Amortization		170,518	-	170,518
16	Taxes other than income taxes		15,249	-	15,249
17	Total operating expenses		901,710	1,712	903,422
18	Net operating income Before Income Tax		332,973	97,656	430,628
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		50,156		50,156
20	Pro Forma Income Tax on Revenue Increase			26,286	26,286
21	Net Income (loss)		$ 282,817	$ 71,369	$ 354,186

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab

Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates Budget For Year End 09/30/27	[3] Test Year At Present Rates Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates Pro Forma Adjusted For Test Year 9/30/27	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 815,696	$ (21,058)	$ 794,638		$ 794,638
2	Comm & Ind (N/NT)	481	295,972	(26,918)	269,053		269,053
3	Comm & Ind (DS)	489	36,322	(313)	36,010		36,010
4	Lg Transport/Other	489	99,453	(1,546)	97,907		97,907
5	Interruptible	489	22,870	73	22,944		22,944
6	Forfeited Discounts	487	6,337	-	6,337		6,337
7	Miscellaneous Service Revenues	488,489,495	4,790	712	5,502		5,502
8	Rent from Gas Properties	493	2,292	-	2,292		2,292
9	Rate Increase			-	-	99,368	99,368
10	Total operating revenues		1,283,732	(49,049)	1,234,682	99,368	1,334,050
	OPERATING EXPENSES						
11	Gas Production		-	-	-		-
12	Gas Supply Production		429,721	(24,749)	404,972		404,972
13	Transmission		-		-		
14	Distribution		93,549	478	94,027		94,027
15	Customer Accounts		62,160	411	62,571		62,571
16	Uncollectible Expense	1.723%	20,671	(330)	20,342	1,712	22,054
17	Customer Information & Services		14,993	(326)	14,666		14,666
18	Sales		1,283	8	1,292		1,292
19	Administrative & General		112,060	6,012	118,072		118,072
20	Depreciation & Amortization		164,574	5,944	170,518		170,518
21	Taxes other than income taxes		14,299	950	15,249		15,249
22	Total operating expenses		913,311	(11,602)	901,710	1,712	903,422
23	Net Operating Income - BIT		$ 370,420	$ (37,448)	$ 332,973	$ 97,656	$ 430,628

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab
Page 1 of 2

Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2]	[3]	[4]	[5]	[6] Adjustments	[7]	[8]	[9]	[10]	[11]	[12]	[13]
	OPERATING REVENUES			D-4	Revenues D-5	Gas Costs D-6	Salaries & Wages D-7	Environmental Expense D-8	Other S&W Costs D-9	Rate Case D-10	Uncollectibles Expense D-11	D-12	D-13	Sub-Total Adjustments	Total Proforma
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 466,312		$ (10,660)									$ (10,660)	$ 455,653
2	Comm & Ind (N/NT)	481	172,874		(11,170)									(11,170)	161,704
3	Comm & Ind (DS)	489	35,486		122									122	35,608
4	Lg Transport/Other	489	98,356		(1,437)									(1,437)	96,920
5	Interruptible	489	22,870		73									73	22,944
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	349,384		(10,398)									(10,398)	338,985
7	Comm & Ind (N/NT)	481	123,098		(15,748)									(15,748)	107,349
8	Comm & Ind (DS)	489	836		(435)									(435)	402
9	Lg Transport/Other	489	1,096		(109)									(109)	987
10	Interruptible Transport	489	-		-									-	-
11	Forfeited Discounts	487	6,337		-									-	6,337
12	Miscellaneous Service Revenues	488,489,495	4,790		712									712	5,502
13	Rent from Gas Properties	493	2,292		-									-	2,292
14			-											-	-
15	Total operating revenues		1,283,732		(49,049)	-	-	-	-	-	-	-	-	(49,049)	1,234,682
	OPERATING EXPENSES														-
16	Gas Production		-				-							-	-
17	Gas Supply Production		429,721			(24,749)								(24,749)	404,972
18	Transmission		-												-
19	Distribution		93,549	-			478						-	478	94,027
20	Customer Accounts		62,160				204							204	62,364
21	Uncollectible Expense		20,671								(330)			(330)	20,342
22	Customer Information & Services		14,993				13						-	13	15,006
23	Sales		1,283				8							8	1,292
24	Administrative & General		112,060	-			239	2,363	-	(537)		-		2,065	114,125
25	Depreciation & Amortization		164,574											-	164,574
26	Taxes other than income taxes		14,299											-	14,299
														-	-
27	Total operating expenses		$ 913,311	$ -	$ -	$ (24,749)	$ 943	$ 2,363	$ -	$ (537)	$ (330)	$ -	$ -	$ (22,310)	$ 891,001
28	Net operating income Before Income Tax		$ 370,420	$ -	$ (49,049)	$ 24,749	$ (943)	$ (2,363)	$ -	$ 537	$ 330	$ -	$ -	$ (26,739)	$ 343,681

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments	[4] Other Adjustments	[5] Universal Service	[6] Adjustments	[7]	[8] EE&C Program	[9]	[10] Depreciation	[11] Taxes Other Than Income	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES			D-14	D-15	D-16	D-17	D-18	D-19		D-21	D-31		
	Customer & Distribution Revenue													
29	Residential (R/RT)	$ 455,653												$ 455,653
30	Comm & Ind (N/NT)	161,704												161,704
31	Comm & Ind (DS)	35,608												35,608
32	Lg Transport/Other	96,920												96,920
33	Interruptible	22,944												22,944
	Revenue for Cost of Gas													-
34	Residential (R/RT)	338,985												338,985
35	Comm & Ind (N/NT)	107,349												107,349
36	Comm & Ind (DS)	402												402
37	Lg Transport/Other	987												987
38	Interruptible Transport	-												-
39	Forfeited Discounts	6,337												6,337
40	Miscellaneous Service Revenues	5,502												5,502
41	Rent from Gas Properties	2,292												2,292
42	-	-												-
43	Total operating revenues	1,234,682	-	-	-	-	-	-	-	-	-	-	-	1,234,682
	OPERATING EXPENSES													
44	Gas Production	-												-
45	Gas Supply Production	404,972												404,972
46	Transmission	-												-
47	Distribution	94,027					-	-						94,027
48	Customer Accounts	62,364			1,624	(1,416)								62,571
49	Uncollectible Expense	20,342												20,342
50	Customer Information & Services	15,006							(340)					14,666
51	Sales	1,292			-									1,292
52	Administrative & General	114,125		3,071	876									118,072
53	Depreciation & Amortization	164,574									5,944			170,518
54	Taxes other than income taxes	14,299										950		15,249
55	Total operating expenses	$ 891,001	$ -	$ 3,071	$ 2,500	$ (1,416)	$ -	$ -	$ (340)	$ -	$ 5,944	$ 950	$ -	$ 901,710
56	Net operating income Before Income Tax	$ 343,681	$ -	$ (3,071)	$ (2,500)	$ 1,416	$ -	$ -	$ 340	$ -	$ (5,944)	$ (950)	$ -	$ 332,973

UGI Utilities, Inc. - Gas Division | **Schedule D-5**
Before the Pennsylvania Public Utility Commission | **Witness: S. A. Epler**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Adjustment - Revenue Adjustments

Line #	Description	Reference Or Account Number	[1] 2027 Budget	[2] PRO FORMA ADJUSTMENTS Other Adjustments	[3] PRO FORMA ADJUSTMENTS Rev/PGC Adj Annualization	[4] PRO FORMA ADJUSTMENTS Total Proforma Adjustments D-5A	[5] Proforma Adjusted At Present Rates
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 466,312	$ (10,660)		$ (10,660)	$ 455,653
2	Comm & Ind (N/NT)	481	172,874	(11,170)		(11,170)	161,704
3	Comm & Ind (DS)	489	35,486	122		122	35,608
4	Lg Transport/Other	489	98,356	(1,437)		(1,437)	96,920
5	Interruptible	489	22,870	73		73	22,944
6	Cust Chg & Distrib Revenue		795,899	(23,071)	-	(23,071)	772,828
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	349,384	(1,011)	(9,387)	(10,398)	338,985
8	Comm & Ind (N/NT)	481	123,098	(386)	(15,362)	(15,748)	107,349
9	Comm & Ind (DS)	489	836	(435)		(435)	402
10	Lg Transport/Other	489	1,096	(109)		(109)	987
11	Interruptible Transport	489	-	-		-	-
12	Revenue for Cost of Gas		474,414	(1,941)	(24,749)	(26,690)	447,723
							-
13	Total Customer Revenue		1,270,313	(25,012)	(24,749)	(49,761)	1,220,551
14	Forfeited Discounts	487	6,337		-	-	6,337
15	Miscellaneous Service Revenues	488 & 489.3	3,178		-	-	3,178
16	Rent from Gas Properties	493	2,292		-	-	2,292
17	Other Revenues	495	1,612	712		712	2,324
18	TOTAL REVENUES		$ 1,283,732	$ (24,300)	$ (24,749)	$ (49,049)	$ 1,234,682

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-5A
Witness: S. A. Epler
Page 1 of 1

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 815,696	$ 794,638	$ (21,058)	
2	Comm & Ind (N/NT)		295,972	269,053	(26,918)	
3	Comm & Ind (DS)		36,322	36,010	(313)	
4	Lg Transport/Other		99,453	97,907	(1,546)	
5	Interruptible		22,870	22,944	73	
6	Total		$ 1,270,313	$ 1,220,551	$ (49,761)	$ (49,761)
COST OF COMMODITY						
7	Residential (R/RT)		$ 349,384	338,985	$ (10,398)	
8	Comm & Ind (N/NT)		123,098	107,349	(15,748)	
9	Comm & Ind (DS)		836	402	(435)	
10	Lg Transport/Other		1,096	987	(109)	
11	Interruptible		0	(0)	(0)	
12	Total		$ 474,414	$ 447,723	$ (26,690)	$ (26,690)
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 466,312	$ 455,653	$ (10,660)	
14	Comm & Ind (N/NT)		172,874	161,704	(11,170)	
15	Comm & Ind (DS)		35,486	35,608	122	
16	Lg Transport/Other		98,356	96,920	(1,437)	
17	Interruptible		22,870	22,944	73	
18	Total		$ 795,899	$ 772,828	$ (23,071)	$ (23,071)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-5B
Witness: D. T. Espigh
Page 1 of 1

Adjustment - CIAC on Tax Gross-Ups

Line #	Description	[1] Factor Or Reference	[2] Other Adjustments	[3] Total
1	Amortization of Tax Gross-up		$ 712	$ 712
2	Total ProForma Adjustment			$ 712

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-6
Witness: S. A. Epler
Page 1 of 1

Adjustment - Gas Costs

Line #	Description	[1] Budgeted Gas Costs	[2] PRO FORMA ADJUSTMENTS D-5A Gas Costs	[3]	[4] Gas Cost Pro Forma Adjustments	[5] Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 429,721			$ -	$ 429,721
2	Residential (R/RT)		(9,387)		(9,387)	(9,387)
3	Comm & Ind (N/NT)		(15,362)		(15,362)	(15,362)
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 429,721	$ (24,749)	$ -	$ (24,749)	$ 404,972

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/27	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	29,446	-	29,446	340	29,786
5	Customer Account Operations Expenses	17,626	-	17,626	204	17,829
6	Total Cust. Service & Inform. Operations Exp	1,164	-	1,164	13	1,178
7	Total Operation Sales Expenses	715	-	715	8	723
8	Total A & G Operation Expenses	19,772	-	19,772	228	20,000
9	Total Operations	68,723	-	68,723	794	69,517
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	11,944	-	11,944	138	12,082
14	Total A&G Maintenance	912	-	912	11	923
15	Total Maintenance	12,856	-	12,856	149	13,005
16	Total Payroll to Expense	$ 81,579	$ -	$ 81,579	$ 943	$ 82,522
17	Percent Increase					1.156%

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Increase At 6-1	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-27		$ 35,161	$ 18,463	$ 27,955	$ 81,578
	Annualize for Wage Increase to 9-30-27					
2	Percent Increase		4.00%	4.00%	4.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/26	67%			
4	Non-Exempt Annualization Factor	10/1/26		0%		
5	Exempt Annualization Factor	10/1/26			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	942	0	0	$ 942
7	Annualized Salaries & Wages at 9-30-27 Rates	L 1 + L 6	$ 36,103	$ 18,463	$ 27,955	
8	Adjustments from Schedule D-9				$ -	
9	Pro Forma Salaries & Wages for TY		$ 36,103	$ 18,463	$ 27,955	
10	Pro Forma Adjustment to S&W					$ 942
11	Annualization Factor	L 10 / L 1				1.155%

Adjustment - Environmental

Line #	Description	[1] Amount		[2] Total
Environmental Adjustment - #1				
1	2023 Environmental expenditures	$ 5,441		
2	2024 Environmental expenditures	7,602		
3	2025 Environmental expenditures	7,052		
4	Three year average of Environmental expenditures	6,698		
5	Budgeted Environmental Expense	$ 5,429		
6	Pro Forma Adjustment			$ 1,269
Environmental Adjustment - #2				
7	(Over) Recovery through 9/30/2026 Related to Prior Rate Case approvals	$ (914)	**(1)**	
8	Under Recovery related to 2025 expenditures	1,880	**(1)**	
9	Under recovered expenditures as of 9/30/2026	$ 967		
10	Amortization Period - 2 years	2		
11	Pro Forma Adjustment	483		
12	Amortization expense for under recovery included in budget	(610)		
13	Pro Forma Adjustment			$ 1,093

(1) See reconciliation of these amounts at UGI Gas Exhibit AMK-2

Adjustment - Rate Case Expense

Line #	Description	[1] Reference	[2] Amount	[3] Total
	Rate Case Expenditures			
1	External Consultants		$ 917	
2	External Legal		750	
3	Miscellaneous Costs		93	
4	Sub-Total	L 1 to L 3		1,760
	Total Expenditures for Rate Case Filing			
5	TOTAL COSTS	L 4		$ 1,760
6	Normalized over 1 year (Line 5 / Line 6, Column 2)		1	$ 1,760
7	Rate Case Expense included in Budget			2,297
8	Pro Forma Adjustment	L 6 - L 7		$ (537)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-11
Witness: V. K. Ressler

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2]/[3]	[5] Total [2]/[3]
Adjustment #1:						
1	2023		$ 23,142	$ 1,210,517	1.91%	
2	2024		$ 17,089	$ 1,020,566	1.67%	
3	2025		$ 17,879	$ 1,140,677	1.57%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 19,370	$ 1,123,920		1.723%
5	2027 Budget				$ 21,469	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.723%		$ 1,226,888		
7	Pro Forma at Present Rate Revenue	[1] * [3]			21,139	
8	Total for Test Year					$ (330)

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-14**
Before the Pennsylvania Public Utility Commission | **Witness:** | **A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Adjustment - Benefits Adjustments

Line #	Description	[1] Amount	[2] Subtotal	[3] Pro Forma Adjustment
Pension Expense Adjustment				
1	Total budgeted pension expense (income)		$ 1,437	
2	Total cash contributions per estimate	12,940		
3	Estimated Cash Contributions attributable to UGI Gas	8,049		
4	Less: estimated capitalized portion	(3,541)		
5	Pension cash contributions per updated estimates		4,507	
6	Pro Forma Adjustment - Pension			$ 3,071

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-15
Witness: V. K. Ressler
Page 1 of 1

Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
Injuries & Damages Reserve Adjustment			
1	2023 Injuries & Damages Expense	$ 2,415	
2	2024 Injuries & Damages Expense	2,090	
3	2025 Injuries & Damages Expense	1,083	
4	Three Year Average of Injuries and Damages Expense	1,863	
5	Budgeted Injuries and Damanges Expense	$ 987	
6	Pro Forma Adjustment		$ 876
Customer Accounts Expense Adjustment			
7	Unrecovered Interest on Customer Deposits		$ 1,624
PUC Assesment			
8	2027 Projected PUC Assessment Expense	$ 6,006	
9	Budgeted PUC Assessment Expense	$ 5,131	
10	Pro Forma Adjustment		$ 875

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase for Pro Forma TY Universal Service Expense	
1	Customer Assistance Plan Credit	$ 23,005
2	Administration Costs	1,492
3	LIURP	4,693
4	Hardship Program (Project Share)	34
5	Customer Assistance Plan Pre-program Arrearage	3,023
6	TOTAL	$ 32,247
7	Adjusted Budget	$ 30,831
8	Adjustment	$ (1,416)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-19
Witness: S. A. Epler
Page 1 of 1

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2027 Original Program Costs	$ 12,366	
2	Adjusted Budget	$ 12,026	
3	Additional Expense Adjustment (Line 2 - Line 1)		(340)
4	Total Adjustment		$ (340)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-21
Witness: J.F. Weidmayer

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/27 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
					-
17	TOTAL PRODUCTION & GATHERING		-	-	-
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		-	-	-

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/27 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	11	(0)	11
32	Structures & Improvements	366	0	(0)	0
33	Mains	367	390	9	399
34	Measuring & Regulating Station Equipment	369	92	(5)	87
35	Communication Equipment	370	92	(15)	77
36	Other Equipment	371	6	(1)	5
37	TOTAL TRANSMISSION		591	(12)	579
DISTRIBUTION PLANT					
38	Land & Land Rights	374	42	0	43
39	Structures & Improvements	375	281	(137)	144
40	Mains	376	51,851	(455)	51,396
41	Measuring & Regulating Station Equipment	378	6,495	(220)	6,275
42	Measuring & Regulating Station Equipment	379	2,057	177	2,234
43	Services	380	56,156	(4,435)	51,721
44	Meters	381	6,804	1,047	7,851
45	Meter Installations	382	3,245	464	3,709
46	House Regulators	383	1,438	(1,232)	206
47	House Regulatory Installations	384	348	(29)	319
48	Industrial Measuring & Reg. Station Equipment	385	953	(156)	798
49	Other Property	386	25	2	27
50	Other Equipment	387	92	(3)	89
51	TOTAL DISTRIBUTION		129,788	(4,977)	124,811
GENERAL PLANT					
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	7,915	1,044	8,959
54	Office Furniture & Equipment	391	23,884	2,473	26,357
55	Transportation Equipment	392	7,087	1,200	8,288
56	Stores Equipment	393	1	0	1
57	Tools & Garage Equipment	394	2,378	(19)	2,360
58	Laboratory Equipment	395	22	0	22
59	Power Operated Equipment	396	915	(82)	833
60	Communication Equipment	397	141	123	264
61	Miscellaneous Equipment	398	67	19	86
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		42,411	4,759	47,170
64	TOTAL DEPRECIATION		$ 172,790	$ (231)	$ 172,559
65	CHARGED TO CLEARING ACCOUNTS		$ (10,522)	$ (1,223)	$ (11,745)
66	NET SALVAGE AMORTIZATION		$ 10,899	$ (1,197)	$ 9,703

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-31
Witness: T. A. Hazenstab
Page 1 of 1

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Budget Amounts 9/30/27	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/27
1	PURTA Taxes	408.1		$ 1,420	$ -	$ 1,420
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		1,250	-	1,250
4	Social Security	408.1	D-32	6,175	71	6,246
5	FUTA	408.1	D-32	6	-	6
6	SUTA	408.1	D-32	317	4	321
7	PUC Assessment	408.1		5,131	875	6,006
8	Total			$ 14,299	$ 950	$ 15,249

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-32**
Before the Pennsylvania Public Utility Commission | **Witness:** | **T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/27 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 81,579	$ 943	
2	FICA Expense		6,175		
3	FICA Expense - Percent	L 2 / L 1	7.57%	7.57%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 71
5	FUTA Expense		6		
6	FUTA Expense - Percent	L 5 / L 1	0.01%	0.01%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		317		
9	SUTA Expense - Percent	L 8 / L 1	0.39%	0.39%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			4
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 75

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-33**
Before the Pennsylvania Public Utility Commission | **Witness:** | **D. T. Espigh**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,234,682	$ 99,368	$ 1,334,050
2	Operating Expenses			(901,710)	(1,712)	(903,422)
3	OIBIT	L 1 + L 2		332,973	97,656	430,628
	Interest Expense					
4	Rate Base	Sch A-1	4,319,352			
5	Weighted Cost of Debt	Sch B-7	0.02370			
6	Synchronized Interest Expense	L 4 * L 5		(102,369)	-	(102,369)
7	Base Taxable Income	L 3 + L 6		230,604	97,656	328,259
8	Total State Tax Depreciation	Sch D-34	$ 328,424			
9	Pro Forma State Book Depreciation	Sch D-34	177,694			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(150,731)		(150,731)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 79,873	$ 97,656	$ 177,529
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	7.49%	$ (5,982)	$ (7,314)	$ (13,297)
14	Total Federal Tax Depreciation	Sch D-34	$ 310,652			
15	Pro Forma Federal Book Depreciation	Sch D-34	177,694			
16	Federal Tax Deducts (Over) Under Book	L 15 - L 14		(132,959)	-	(132,959)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		91,662	90,341	182,004
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(19,249)	(18,972)	(38,221)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(25,231)	(26,286)	(51,518)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 172,559			
22	Total Tax Depreciation	L 15 - Sch D-34 L 2	299,318			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		126,759	-	126,759
24	Deferred Federal Taxable Income	L 23		$ 126,759	$ -	$ 126,759
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(22,607)	-	(22,607)
	Deferred State Income Taxes					
26	Repairs			(2,943)		(2,943)
27	CIAC			26		26
28	State Deferred Income Tax (Expense)/Refund			(2,917)	-	(2,917)
29	Net Income Tax Expense	L20 + L 25 + L28		(50,755)	(26,286)	(77,042)
	Other Tax Adjustments					
30	ITC			599		599
31	Combined Income Tax Expense	L 29 + L 30		$ (50,156)	$ (26,286)	$ (76,442)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (41,256)	$ (18,972)	$ (60,228)
33	State Income Tax Expense	L 13 + L 28		(8,900)	(7,314)	(16,214)
34	Total Income Tax Expense	L 32 + L 33		$ (50,156)	$ (26,286)	$ (76,442)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-34**
Before the Pennsylvania Public Utility Commission | **Witness:** | **D. T. Espigh**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 211,544	
2	Cost of Removal		11,334	
3	Repairs Tax Deduction		110,774	
4	Other Tax Basis Adjustments		(23,000)	
5	Total Federal Accelerated Tax Depreciation			$ 310,652
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		17,772	
7	Total State Accelerated Tax Depreciation			$328,424
	Straight Line Tax Depreciation			
8	Gas Plant		$ 172,559	
9	Total Tax Depreciation			$ 172,559
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 172,559	
11	Net Salvage Amortization		9,703	
12	Depreciation Charged to Clearing Accounts	(11,745)		
13	Estimated Percent of Clearing Charged to CWIP	38.9%		
14	Depreciation Charged to CWIP		(4,569)	
15	Book Depreciation for Tax Calculation			$ 177,694

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-35**
Before the Pennsylvania Public Utility Commission | **Witness:** | **T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.017230)
3	NET REVENUES	Sum L 1 to L 2		0.982770
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	7.4900%	(0.073609)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.909161
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.190924)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.718237
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.392298
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		26.453%
INCOME TAX FACTOR				
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	7.4900%	(0.074900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.925100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.194271)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.730829
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.368309
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		26.917%

UGI GAS

EXHIBIT A

FUTURE

Future Period - 12 Months Ended September 30, 2026
($ in Thousands)
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B-3	Statement of Operating Revenues	T. A. Hazenstab
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C-1	Measure of Value	A. M. Keller
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	Pro Forma Year End Plant Balances	A. M. Keller
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C-3	Accumulated Provision for Depreciation	A. M. Keller
	Summary of Accumulated Depreciation	A. M. Keller
	Accumulated Depreciation by FERC Account	A. M. Keller
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	Negative Net Salvage Amortization	A. M. Keller
	Salvage	A. M. Keller
C-4	Working Capital	A. M. Keller
	Summary of Working Capital	A. M. Keller
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	Summary of Expense Lag Calculations	A. M. Keller
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C-5	Gas Inventory	A. M. Keller
C-6	Accumulated Deferred Income Taxes	D. T. Espigh
C-7	Customer Deposits	A. M. Keller
C-8	Materials & Supplies	A. M. Keller
C-9	SCHEDULE NOT USED	N/A

Future Period - 12 Months Ended September 30, 2026

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D-4	SCHEDULE NOT USED	N/A
D-5	Adjustment - Revenue Adjustments	S. A. Epler
D-5A	Adjustment - Test Year Revenue Changes	S. A. Epler
D-5B	Adjustment - Amortization of Tax Gross-up on CIAC for Interconnects	D. T. Espigh
D-6	Adjustment - Gas Costs	S. A. Epler
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D-8	SCHEDULE NOT USED	N/A
D-9	SCHEDULE NOT USED	N/A
D-10	SCHEDULE NOT USED	N/A
D-11	Adjustment - Uncollectibles	V. K. Ressler
D-12	SCHEDULE NOT USED	N/A
D-13	SCHEDULE NOT USED	N/A
D-14	SCHEDULE NOT USED	N/A
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D-16	Adjustment - Universal Service	S. A. Epler
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D-21	Adjustment - Depreciation expense	J.F. Weidmayer
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D-32	Adjustment - Payroll Taxes	T. A. Hazenstab
D-33	Income Tax Calculation	D. T. Espigh
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UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2026 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 6,208,881		$ 6,208,881
2	Accumulated Depreciation		C-3	(1,613,591)		(1,613,591)
3	Net Plant in service	L 1 + L 2		4,595,290	-	4,595,290
4	Working Capital		C-4	65,217		65,217
5	Gas Inventory		C-5	23,662		23,662
6	Accumulated Deferred Income Taxes		C-6	(708,649)		(708,649)
7	Customer Deposits		C-7	(23,197)		(23,197)
8	Materials & Supplies		C-8	28,644		28,644
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 3,980,967	$ -	$ 3,980,967
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 806,652	$ 42,743	$ 849,395
11	Gas Cost Revenue		D-5	403,778		403,778
12	Other Operating Revenues		D-5	14,181		14,181
13	Total Revenues	Sum L 10 to L 12		1,224,611	42,743	1,267,354
14	Operating Expenses		D-1	(872,170)	(736)	(872,907)
15	OIBIT	L 13 + L 14		352,441	42,007	394,447
16	Pro Forma Income Tax at Present Rates		D-33	(57,332)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(11,473)	(68,805)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 295,109	$ 30,533	$ 325,643
19	RATE OF RETURN	L 18 / L 9		7.4130%		8.1800%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		7.4130%		
21	Rate of Return Required		B-7	8.1800%		
22	Change in ROR	L 21 - L 20		0.7670%		
23	Change in Operating Income	L 22 * L 9		$ 30,534		
24	Gross Revenue Conversion Factor		D-35	1.399864		
25	Change in Revenues	L 23 * L 24		$ 42,743		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, Col 3			5.30%	
27	Percent Increase -- Total Revenues	L 25 / L 13, Col 3			3.49%	

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-26
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 5,795,922
2	Other Utility Plant	-
3	Total Plant In Service	5,795,922
4	Construction Work In Progress (107)	103,448
5	Total Utility Plant	5,899,370
6	Accumulated Provision for Depreciation - Gas (108)	(1,509,518)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	4,571,997
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	714
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,168
13	Other Investments (124)	15
14	Total Other Property and Investments	1,897
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	15,093
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	104,269
18	Other Accounts Receivable (143)	13,706
19	Accum Provision for Uncollectible (144)	(14,137)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	3,596
22	Plant Materials & Operating Supplies (154)	23,722
23	Stores Expense - Undistributed (163)	2,470
24	Gas Stored - Current (164.1)	48,214
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	20,265
27	Accrued Utility Revenues (173)	23,358
28	Miscellaneous Current & Accrued Assets (174)	148
29	Derivative Instrument Assets (175)	2,244
30	Total Current and Accrued Assets	242,949
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	8,074
32	Other Regulatory Assets (182.3)	484,302
33	Other Preliminary Survey & Investigation Charges (183.2)	48
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	14,260
36	Def. Losses from Disposition of Utility Plt. (187)	-
37	Unamortized Loss on Reacquired Debt (189)	-
38	Accumulated Deferred Income Taxes (190)	-
39	O/U Collected Gas (191.4, 191.41)	-
40	Total Deferred Debits	506,683
41	TOTAL ASSETS AND OTHER DEBITS	$ 5,323,526

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-26
	PROPRIETARY CAPITAL	
42	Common Stock Issued (201)	$ 53,926
43	Preferred Stock Issued (204)	-
44	Premium on Capital Stock (207)	535,399
45	Capital Stock Expense (214)	-
46	Retained Earnings (215, 215.2, 216)	1,222,601
47	Accum Other Comprehensive Income (219)	(12,094)
48	Total Proprietary Capital	1,799,832
	LONG TERM DEBT	
49	Bonds (221)	-
50	Advances from Associated Companies (223)	-
51	Other Long-Term Debt (224)	1,854,997
52	Unamortized Premium on LTD (225)	-
53	Unamortized Discount on LTD (226)	-
54	Total Long-term Debt	1,854,997
	OTHER NON-CURRENT LIABILITIES	
55	Obligations under Capital Leases (227)	163
56	Accum. Prov for Injuries & Damages (228.2)	1,890
57	Accum. Prov for Pensions & Benefits (228.3)	(0)
58	Accum. Miscellaneous Operating Prov (228.4)	52,272
59	Asset Retirement Obligation (230)	111
60	Total Non-Current Liabilities	54,436
	CURRENT & ACCRUED LIABILITIES	
61	Notes Payable (231)	252,147
62	Accounts Payable (232)	91,381
63	Notes Payable to Assoc. Companies (233)	-
64	Accounts Payable to Assoc. Cos (234)	6,308
65	Customer Deposits (235)	23,852
66	Taxes Accrued (236)	(10,612)
67	Interest Accrued (237)	21,850
68	Tax Collections Payable (241)	755
69	Misc Current & Accrued Liabilities (242)	84,609
70	Obligations Under Capital Leases (243)	504
71	Derivative Instrument Liabilities (244)	6,278
72	Total Current & Accrued Liabilities	477,074
	OTHER DEFERRED CREDITS	
73	Customer Advances for Construction (252)	-
74	Other Deferred Credits (253)	21,004
75	Other Regulatory Liabilities (254)	265,740
76	Deferred ITC (255)	791
77	Accumulated Deferred Income Taxes (282)	797,103
78	Accumulated Deferred Income Taxes (283)	52,548
79	Total Other Deferred Credits	1,137,187
80	TOTAL LIABILITIES & OTHER CREDITS	$ 5,323,526

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule B-2
Witness: T. A. Hazenstab

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-26	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 1,256,178	B-3
2	Other Operating Revenues	13,334	B-3
3	Total Revenues	1,269,512	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	717,012	B-4
5	Depreciation & Amortization Expense	153,978	D-2
6	Taxes Other Than Income Taxes	13,359	B-5
7	Total Operating Expenses	884,349	
8	Operating Income Before Income Taxes (OIBIT)	385,163	
	Income Taxes:		
9	State	11,377	B-5
10	Federal	45,954	B-5
11	Total Income Taxes	57,332	
12	**Net Utility Operating Income**	$ 327,831	

Statement of Operating Revenues

Line No	Description	[1] Budget TYE 9-30-26
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 804,333
2	Comm & Ind (N/NT) (481)	294,701
3	Comm & Ind (DS) (489)	35,926
4	Lg Transport/Other (489)	99,227
5	Interruptible (489)	21,992
6	Sub-Total Gas Operating Revenues	1,256,178
	Other Operating Revenues	
7	Forfeited Discounts (487)	6,261
8	Miscellaneous Service Revenues (488)	3,178
9	Rent from Gas Properties (493)	2,292
10	Other Revenues (495)	1,603
11	Sub-Total Other Operating Revenues	13,334
12	**Total Operating Revenues**	$ 1,269,512

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-26
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	-
3	Total Gas Raw Materials Expenses		-
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	530,074
16	Other Gas Purchases	805.0	5
17	Purchases Gas Cost Adjustments	805.1	(86,489)
18	Gas Withdrawn from Storage-Debit	808.1	47,230
19	Purchased Gas Expenses	807.0	-
20	Gas Used for Other Utility Operations-Credit	812.0	2,169
21	Gas Delivered to Storage-Credit	808.2	(62,675)
22	Other Gas Supply Expenses	813.0	(5,211)
23	Gas Supply Operation Expenses		425,103
	Underground Storage Expense - Operation		
24	Operation Supervision and Engineering	814	-
25	Maps and Records	815	-
26	Wells Expenses	816	-
27	Lines Expenses	817	-
28	Measuring and Regulating Station Expenses	820	-
29	Purification Expenses	821	-
30	Gas Losses	823	-
31	Other Expenses	824	-
32	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
33	Maintenance Supervision and Engineering	830	-
34	Maintenance of Structures and Improvements	831	-
35	Maintenance of Reservoirs and Wells	832	-
36	Maintenance of Lines	833	-
37	Maintenance of Measuring & Regulating Station Equip.	835	-
38	Total Underground Maintenance Expenses		-

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-26
	Transmission Expense - Operations		
39	Operating Supervision and Engineering	850	-
40	System Control and Load Dispatching	851	-
41	Communication System Expenses	852	-
42	Mains Expenses	856	-
43	Measuring and Regulating Station Expenses	857	-
44	Other Expenses	859	-
45	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
46	Maintenance Supervision and Engineering	861	-
47	Maintenance of Structures and Improvements	862	-
48	Maintenance of Mains	863	-
49	Maintenance of Measuring and Regulating Station Equip.	865	-
50	Maintenance of Communication Equipment	866	-
51	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
52	Operation Supervision and Engineering	870	5,815
53	Distribution Load Dispatching	871	3,260
54	Compressor Station Fuel and Power (Major Only)	873	-
55	Mains and Services Expenses	874	32,966
56	Measuring and Regulating Station Expenses-General	875	2,101
57	Measuring and Regulating Station Expenses-Industrial	876	20
58	Measuring and Regulating Station Expenses-City Gate	877	416
59	Meter and House Regulator Expenses	878	3,470
60	Customer Installations Expenses	879	3,165
61	Other Expenses	880	6,989
62	Rents	881	643
63	Total Distribution Operation Expenses		58,843
	Distribution Expense - Maintenance		
64	Maintenance Supervision and Engineering	885	2,201
65	Maintenance of Structures and Improvements	886	-
66	Maintenance of Mains	887	20,684
67	Maintenance of Compressor Station Equipment	888	-
68	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	2,276
69	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	3,809
70	Maintenance of Measuring & Reg. Station Equip.-City G	891	106
71	Maintenance of Services	892	673
72	Maintenance of Meters & House Regulators	893	42
73	Maintenance of Other Equipment	894	580
74	Construction & Maintenance	895	-
75	Total Distribution Maintenance Expenses		30,371
	Customer Accounts Expense - Operations		
76	Supervision	901	826
77	Meter Reading Expenses	902	2,777
78	Customer Records & Collection Expenses	903	56,147
79	Uncollectable Accounts	904	20,409
80	Miscellaneous Customer Accounts Expenses	905	67
81	Total Administrative & General		80,226

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-26
	Customer Service & Information Expense		
82	Supervision	907	84
83	Customer Assistance Expenses	908	1,040
84	Informational & Instructional Advertising Expenses	909	1,293
85	Miscellaneous Customer Service & Informational Exp.	910	12,347
86	Total Cust. Service & Inform. Operations Exp		14,764
	Sales Expense		
87	Supervision	911	-
88	Demonstrating and Selling Expenses	912	718
89	Advertising Expenses	913	532
90	Miscellaneous Sales Expenses	916	-
91	Total Operation Sales Expenses		1,250
	Administrative & General - Operations		
92	Administrative and General Salaries	920.0	34,066
93	Office Supplies and Expenses	921.0	18,291
94	Outside Service Employed	923.0	21,235
95	Property Insurance	924.0	394
96	Injuries and Damages	925.0	10,395
97	Employee Pensions and Benefits	926.0	14,063
98	Regulatory Commission Expenses	928.0	1,160
99	General Advertising Expenses	930.1	149
100	Miscellaneous General Expenses	930.2	1,549
101	Rents	931.0	57
102	Total A & G Operation Expenses		101,359
	Administrative & General - Maintenance		
103	A&G Maintenance of General Plant	932	5,097
104	A&G Maintenance of General Plant	935	-
105	Total A & G Maintenance Expenses		5,097
106	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 717,012
107	Total Gas Operation Expenses		681,545
108	Total Gas Maintenance Expense		35,467
109	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 717,012

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule B-5
Witness: T. A. Hazenstab

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-26
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 1,291
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	1,203
4	PUC Assessment	D-31	4,665
5	Subtotal		7,159
	Payroll Taxes		
6	FICA	D-31	5,832
7	SUTA	D-31	361
8	FUTA	D-31	7
9	Other		-
10	Subtotal		6,200
11	Total Taxes Other Than Income Taxes		$ 13,359
	Income Taxes		
12	State		$ 11,377
13	Federal		45,954
14	Total Income Taxes		$ 57,332

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule B-6
Witness: D. W. D'Ascendis

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4]*[5]
Medium Term Notes							
1	6.50%	8/14/2003	8/15/2033	$ 20,000	1.03%	6.56%	0.07%
2	6.13%	10/14/2004	10/15/2034	20,000	1.03%	6.19%	0.06%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	5.17%	6.32%	0.33%
4	4.980%	3/26/2014	3/26/2044	175,000	9.04%	5.00%	0.45%
5	4.120%	9/30/2016	9/30/2046	200,000	10.33%	5.01%	0.52%
6	4.120%	10/31/2016	10/31/2046	100,000	5.17%	4.28%	0.22%
7	4.550%	2/1/2019	2/1/2049	150,000	7.75%	4.58%	0.35%
8	3.120%	3/19/2020	4/16/2050	150,000	7.75%	3.15%	0.24%
9	4.750%	7/15/2022	7/15/2032	90,000	4.65%	4.82%	0.22%
10	4.990%	9/15/2022	9/15/2052	85,000	4.39%	5.03%	0.22%
11	6.100%	11/30/2023	11/30/2033	150,000	7.75%	6.17%	0.48%
12	6.400%	11/30/2023	11/30/2053	75,000	3.88%	6.43%	0.25%
13	6.020%	11/30/2023	11/30/2030	25,000	1.29%	6.11%	0.08%
14	5.240%	11/14/2024	11/30/2029	50,000	2.58%	5.38%	0.14%
15	5.520%	11/14/2024	11/30/2034	125,000	6.46%	5.60%	0.36%
16	5.100%	11/14/2025	11/14/2035	150,000	7.75%	5.16%	0.40%
17	5.680%	11/14/2025	11/14/2035	125,000	6.46%	5.75%	0.37%
18	5.600%	1/31/2026	6/30/2036	75,000	3.88%	5.67%	0.22%
					0.00%		0.00%
Term Loan							
19	3.917%	10/31/2017	7/12/2027	70,313	3.63%	3.96%	0.14%
20	Total Long-Term Debt			$ 1,935,313	100.00%		5.12%
21	Total Long-Term Debt			$ 1,935,313	100.00%	5.12%	5.12%
22	Total Short-Term Debt				0.00%		0.00%
23	TOTAL			$ 1,935,313	100.00%		
24	Weighted Cost of Debt						5.12%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule B-7
Witness: D. W. D'Ascendis

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	45.63%	5.12%	B-6	2.34%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	54.37%	10.75%		5.84%
4	Total	100.00%			8.18%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule C-1
Witness: A. M. Keller
Page 1 of 1

Measure of Value

Line #	Description	[1] Reference Schedule	[2] # of Pages	[3] Pro Forma Test Year Ended September 30, 2026 At Present Rates	[4] Adjustments	[5] Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 6,208,881		$ 6,208,881
2	Accumulated Depreciation	C-3	11	(1,613,591)		(1,613,591)
3	Net Plant in service			4,595,290	-	4,595,290
4	Working Capital	C-4	9	65,217		65,217
5	Gas Inventory	C-5	1	23,662		23,662
6	Accumulated Deferred Income Taxes	C-6	1	(708,649)		(708,649)
7	Customer Deposits	C-7	1	(23,197)		(23,197)
8	Materials & Supplies	C-8	1	28,644		28,644
9	TOTAL MEASURE OF VALUE			$ 3,980,967	$ -	$ 3,980,967

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-26
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-26
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,468
34	Measuring & Regulating Station Equipment	369	6,173
35	Communication Equipment	370	3,505
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,575
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,638
39	Structures & Improvements	375	7,923
40	Mains	376	2,956,090
41	Measuring & Regulating Station Equipment	378	191,451
42	Measuring & Regulating Station Equipment	379	81,780
43	Services	380	1,799,933
44	Meters	381	205,771
45	Meter Installations	382	147,331
46	House Regulators	383	10,274
47	House Regulatory Installations	384	17,829
48	Industrial Measuring & Reg. Station Equipment	385	41,443
49	Other Property	386	1,274
50	Other Equipment	387	6,799
51	TOTAL DISTRIBUTION		5,479,536
	GENERAL PLANT		
52	Land & Land Rights	389	14,128
53	Structures & Improvements	390	224,104
54	Office Furniture & Equipment	391	298,038
55	Transportation Equipment	392	77,031
56	Stores Equipment	393	16
57	Tools & Garage Equipment	394	45,411
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	13,798
60	Communication Equipment	397	3,095
61	Miscellaneous Equipment	398	1,937
62	Other Tangible Property	399	-
63	TOTAL GENERAL		677,996
64	Total Plant		$ 6,208,881

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/26 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	-	-	-
4	Transmission Plant	Sch C-2, Page 5	50,575	-	50,575
5	Distribution Plant	Sch C-2, Page 5	5,479,536	-	5,479,536
6	General Plant	Sch C-2, Page 5	677,996	-	677,996
7	Other Plant		-	-	-
8	Total Utility Plant		$ 6,208,881	$ -	$ 6,208,881

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ 290	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	194	-	194
3	Miscellaneous Intangible Plant	303	290	290	-	290
4	TOTAL INTANGIBLE		774	774	-	774
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	-	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-	-

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	47	47	-	47
31	Rights of Way	365.2	868	868	-	868
32	Structures & Improvements	366	162	162	-	162
33	Mains	367	39,468	39,468	-	39,468
34	Measuring & Regulating Station Equipment	369	6,173	6,173	-	6,173
35	Communication Equipment	370	3,505	3,505	-	3,505
36	Other Equipment	371	351	351	-	351
37	TOTAL TRANSMISSION		50,575	50,575	-	50,575
DISTRIBUTION PLANT						
38	Land & Land Rights	374	11,638	11,638	-	11,638
39	Structures & Improvements	375	7,181	7,923	-	7,923
40	Mains	376	2,752,176	2,956,090	-	2,956,090
41	Measuring & Regulating Station Equipment	378	164,221	191,451	-	191,451
42	Measuring & Regulating Station Equipment	379	81,780	81,780	-	81,780
43	Services	380	1,684,481	1,799,933	-	1,799,933
44	Meters	381	192,839	205,771	-	205,771
45	Meter Installations	382	141,912	147,331	-	147,331
46	House Regulators	383	10,274	10,274	-	10,274
47	House Regulatory Installations	384	17,829	17,829	-	17,829
48	Industrial Measuring & Reg. Station Equipment	385	40,449	41,443	-	41,443
49	Other Property	386	1,274	1,274	-	1,274
50	Other Equipment	387	6,799	6,799	-	6,799
51	TOTAL DISTRIBUTION		5,112,854	5,479,536	-	5,479,536
GENERAL PLANT						
52	Land & Land Rights	389	13,523	14,128	-	14,128
53	Structures & Improvements	390	207,766	224,104	-	224,104
54	Office Furniture & Equipment	391	281,626	298,038	-	298,038
55	Transportation Equipment	392	66,908	77,031	-	77,031
56	Stores Equipment	393	16	16	-	16
57	Tools & Garage Equipment	394	44,808	45,411	-	45,411
58	Laboratory Equipment	395	438	438	-	438
59	Power Operated Equipment	396	13,798	13,798	-	13,798
60	Communication Equipment	397	3,095	3,095	-	3,095
61	Miscellaneous Equipment	398	1,510	1,937	-	1,937
62	Other Tangible Property	399	16	-	-	-
63	TOTAL GENERAL		633,504	677,996	-	677,996
64	Total Plant		$ 5,797,706	$ 6,208,881	$ -	$ 6,208,881

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2025	[3] Year ended September 30, 2026
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2025	[3] 2026
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	952	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		952	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	49	-
39	Structures & Improvements	375	847	759
40	Mains	376	215,764	210,564
41	Measuring & Regulating Station Equipment	378	7,879	27,444
42	Measuring & Regulating Station Equipment	379	17,128	-
43	Services	380	106,301	134,149
44	Meters	381	16,223	15,547
45	Meter Installations	382	6,707	6,296
46	House Regulators	383	95	-
47	House Regulatory Installations	384	220	-
48	Industrial Measuring & Reg. Station Equipment	385	630	1,002
49	Other Property	386	206	-
50	Other Equipment	387	76	-
51	TOTAL DISTRIBUTION		372,126	395,762
GENERAL PLANT				
52	Land & Land Rights	389	-	606
53	Structures & Improvements	390	8,126	16,683
54	Office Furniture & Equipment	391	11,317	43,926
55	Transportation Equipment	392	10,104	11,248
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	2,462	1,834
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	1,749	-
60	Communication Equipment	397	1,118	-
61	Miscellaneous Equipment	398	168	524
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		35,044	74,820
64	Total Plant		$ 408,122	$ 470,582

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	(17)	-
34	Measuring & Regulating Station Equipment	369	(0)	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		(17)	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	(15)	(17)
40	Mains	376	(14,827)	(6,651)
41	Measuring & Regulating Station Equipment	378	(47)	(214)
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	(23,042)	(18,697)
44	Meters	381	(1,323)	(2,615)
45	Meter Installations	382	(139)	(878)
46	House Regulators	383	(1)	-
47	House Regulatory Installations	384	(39)	-
48	Industrial Measuring & Reg. Station Equipment	385	3	(8)
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		(39,431)	(29,079)
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	(345)
54	Office Furniture & Equipment	391	(2,008)	(27,513)
55	Transportation Equipment	392	-	(1,125)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	(1,220)	(1,231)
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	(29)	-
61	Miscellaneous Equipment	398	(337)	(97)
62	Other Tangible Property	399	-	(16)
63	TOTAL GENERAL		(3,593)	(30,327)
64	Total Plant		$ (43,041)	$ (59,406)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-26
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-26
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	583
32	Structures & Improvements	366	157
33	Mains	367	23,526
34	Measuring & Regulating Station Equipment	369	4,348
35	Communication Equipment	370	2,549
36	Other Equipment	371	306
37	TOTAL TRANSMISSION		31,470
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,551
39	Structures & Improvements	375	3,694
40	Mains	376	603,006
41	Measuring & Regulating Station Equipment	378	46,205
42	Measuring & Regulating Station Equipment	379	16,033
43	Services	380	485,016
44	Meters	381	86,841
45	Meter Installations	382	50,079
46	House Regulators	383	5,133
47	House Regulatory Installations	384	9,801
48	Industrial Measuring & Reg. Station Equipment	385	21,131
49	Other Property	386	701
50	Other Equipment	387	4,802
51	TOTAL DISTRIBUTION		1,333,994
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	62,353
54	Office Furniture & Equipment	391	125,461
55	Transportation Equipment	392	33,930
56	Stores Equipment	393	8
57	Tools & Garage Equipment	394	17,652
58	Laboratory Equipment	395	201
59	Power Operated Equipment	396	6,099
60	Communication Equipment	397	1,216
61	Miscellaneous Equipment	398	1,208
62	Other Tangible Property	399	
63	TOTAL GENERAL		248,128
64	Total Plant		$ 1,613,591

Summary of Accumulated Depreciation

Line #	Description	[1] Factor Or Reference	[2] Test Year Ended September 30, 2026 Amount	[3] Pro Forma Adjustment	[4] Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	$ -	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	-	-	-
4	Transmission Plant	Sch C-3, Pg 5	31,470	-	31,470
5	Distribution Plant	Sch C-3, Pg 5	1,333,994	-	1,333,994
6	General Plant	Sch C-3, Pg 5	248,128	-	248,128
7	Other Plant		-	-	-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,613,591	$ -	$ 1,613,591

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	(0)	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	(0)	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		(0)	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	23	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		23	-	-	-

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	-	-	-	-
31	Rights of Way	365.2	572	583	-	583
32	Structures & Improvements	366	157	157	-	157
33	Mains	367	23,116	23,526	-	23,526
34	Measuring & Regulating Station Equipment	369	4,255	4,348	-	4,348
35	Communication Equipment	370	2,463	2,549	-	2,549
36	Other Equipment	371	301	306	-	306
37	TOTAL TRANSMISSION		30,863	31,470	-	31,470
DISTRIBUTION PLANT						
38	Land & Land Rights	374	1,508	1,551	-	1,551
39	Structures & Improvements	375	3,577	3,694	-	3,694
40	Mains	376	563,000	603,006	-	603,006
41	Measuring & Regulating Station Equipment	378	41,529	46,205	-	46,205
42	Measuring & Regulating Station Equipment	379	13,438	16,033	-	16,033
43	Services	380	460,225	485,016	-	485,016
44	Meters	381	82,033	86,841	-	86,841
45	Meter Installations	382	47,685	50,079	-	50,079
46	House Regulators	383	3,921	5,133	-	5,133
47	House Regulatory Installations	384	9,463	9,801	-	9,801
48	Industrial Measuring & Reg. Station Equipment	385	19,979	21,131	-	21,131
49	Other Property	386	675	701	-	701
50	Other Equipment	387	4,707	4,802	-	4,802
51	TOTAL DISTRIBUTION		1,251,741	1,333,994	-	1,333,994
GENERAL PLANT						
52	Land & Land Rights	389	-	-	-	-
53	Structures & Improvements	390	54,861	62,353	-	62,353
54	Office Furniture & Equipment	391	128,790	125,461	-	125,461
55	Transportation Equipment	392	29,187	33,930	-	33,930
56	Stores Equipment	393	7	8	-	8
57	Tools & Garage Equipment	394	16,560	17,652	-	17,652
58	Laboratory Equipment	395	178	201	-	201
59	Power Operated Equipment	396	5,174	6,099	-	6,099
60	Communication Equipment	397	826	1,216	-	1,216
61	Miscellaneous Equipment	398	1,055	1,208	-	1,208
62	Other Tangible Property	399	16	-	-	-
63	TOTAL GENERAL		236,655	248,128	-	248,128
64	Total Plant		$ 1,519,282	$ 1,613,591	$ -	$ 1,613,591

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330		
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305		
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	12	7
40	Mains	376	3,511	1,939
41	Measuring & Regulating Station Equipment	378	313	53
42	Measuring & Regulating Station Equipment	379	196	-
43	Services	380	5,023	7,271
44	Meters	381	94	-
45	Meter Installations	382	95	341
46	House Regulators	383	1,029	-
47	House Regulatory Installations	384	3	-
48	Industrial Measuring & Reg. Station Equipment	385	87	(326)
49	Other Property	386	2	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		10,363	9,287
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	105	31
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	-	-
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	10	-
61	Miscellaneous Equipment	398	87	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		201	31
64	Total Plant		$ 10,565	$ 9,318

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	(23)	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		(23)	-

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	4	3
34	Measuring & Regulating Station Equipment	369	2	1
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		5	4
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	3	4
40	Mains	376	2,705	2,586
41	Measuring & Regulating Station Equipment	378	227	203
42	Measuring & Regulating Station Equipment	379	88	85
43	Services	380	4,744	5,360
44	Meters	381	34	38
45	Meter Installations	382	133	157
46	House Regulators	383	872	872
47	House Regulatory Installations	384	4	1
48	Industrial Measuring & Reg. Station Equipment	385	25	(48)
49	Other Property	386	0	0
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		8,835	9,259
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	132	138
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(872)	(789)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	4	4
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	3	3
61	Miscellaneous Equipment	398	157	78
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(576)	(566)
64	Total Plant		$ 8,241	$ 8,698

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2025	[3] Year Ended September 30, 2026
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	-	-
41	Measuring & Regulating Station Equipment	378	-	-
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	-	-
44	Meters	381	-	-
45	Meter Installations	382	-	-
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		-	-
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	-
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(749)	(112)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(749)	(112)
64	Total Plant		$ (749)	$ (112)

Working Capital

Line No	Description	[1] Fully Projected TYE 9-30-26	[2] Reference
1	Working Capital for O & M Expense	$ 55,358	C-4, Page 2
2	Interest Payments	(8,634)	C-4, Page 7
3	Tax Payment Lag Calculations	4,093	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 65,217	

Summary of Working Capital

Line #	Description	Reference	[1] Test Year Expenses	[2] Factor	[3] Number of (Lead) / Lag Days [2] * [3]	[4] Totals
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				57.37
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 78,063	12.00	$ 936,759	
4	Purchased Gas Costs	Sch D-6	403,778	26.09	10,532,803	
5	Other Expenses	L 18 - L 3 to L 4	193,832	36.55	7,084,564	
6	Total	Sum (L 3 to L 5)	$ 675,674		$ 18,554,126	
7	O & M Expense Lag Days	L6, C 4 / C 2				27.46
8	Net (Lead) Lag Days	L 1 - L 7				29.91
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,851
10	Working Capital for O & M Expense	L 8 * L 9				$ 55,358
11	Interest Payments	Page 7				(8,634)
12	Tax Payment Lag Calculations	Page 8				4,093
13	Prepaid Expenses	Page 9				14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 65,217
15	Pro Forma O & M Expense		$ 698,949			
	Less:					
16	Uncollectible Expense		23,275			
17	Sub-Total		23,275			
18	Pro Forma Cash O&M Expense		$ 675,674			

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]	[5] Days Lag 365 / [4]
1	Annual Number of Days					365
2	September, 2024		$59,595			
3	October		$54,962	$49,570		
4	November		$65,027	$66,062		
5	December, 2024		$115,180	$130,278		
6	January, 2025		$180,732	$200,306		
7	February		$209,136	$183,549		
8	March		$200,671	$160,286		
9	April		$178,319	$106,926		
10	May		$148,644	$67,400		
11	June		$131,419	$49,633		
12	July		$110,237	$42,524		
13	August		$88,906	$37,847		
14	September, 2025		$72,798	$41,343		
15	Total	Sum L 2 to L 14	$1,615,626			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$124,279			
18	Total Sales for Year	Sum L 2 to L 14		$ 1,135,724		
19	Acct Rec Turnover Ratio	L 18 / L 17			9.14	
20	Collection Lag Day Factor	L 1 / L 19				39.93
21	Meter Read Lag Factor					2.23
22	Midpoint Lag Factor		365	/ 12	/ 2	= 15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**57.37**

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 34,153	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	43,910	12.00		
3	Weighted for Union	L1, C2 * C3			$ 409,841	
4	Weighted for Other	L2, C2 * C3			526,920	
5	Payroll Lag	L 3 + L 4	$ 78,063		$ 936,761	
6	Payroll Lag Days	L5, C4 / C2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 505,975		$ 13,198,681	
8	Gas Cost Lag Days	L 7, C4 / C2				26.09
OTHER O & M EXPENSES						
9	October-2024	Page 5	$ 12,404		$ 323,056	
10	November-2024	Page 5	9,141		250,782	
11	December-2024	Page 5	10,855		287,049	
12	January-2025	Page 5	25,282		1,499,042	
13	February-2025	Page 5	15,794		514,617	
14	March-2025	Page 5	9,353		273,241	
15	April-2025	Page 5	12,385		289,995	
16	May-2025	Page 5	13,770		597,078	
17	June-2025	Page 5	14,096		499,028	
18	July-2025	Page 5	20,034		1,249,027	
19	August-2025	Page 5	13,203		391,825	
20	September-2025	Page 5	38,365		941,232	
21	TOTAL		$ 194,681		$ 7,115,972	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				36.55

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
October-2024					
1	Total Disbursements for Month	32,838	$ 62,746		
2	Total Disbursements for Expenses	3,838	$ 12,404	$ 323,056	26.04
November-2024					
3	Total Disbursements for Month	23,901	$ 38,794		
4	Total Disbursements for Expenses	3,565	$ 9,141	$ 250,782	27.43
December-2024					
5	Total Disbursements for Month	24,687	$ 38,022		
6	Total Disbursements for Expenses	4,006	$ 10,855	$ 287,049	26.44
January-2025					
7	Total Disbursements for Month	21,368	$ 50,983		
8	Total Disbursements for Expenses	3,947	$ 25,282	$ 1,499,042	59.29
February-2025					
9	Total Disbursements for Month	18,066	$ 32,989		
10	Total Disbursements for Expenses	3,439	$ 15,794	$ 514,617	32.58
March-2025					
11	Total Disbursements for Month	18,513	$ 27,337		
12	Total Disbursements for Expenses	3,735	$ 9,353	$ 273,241	29.21
April-2025					
13	Total Disbursements for Month	25,630	$ 41,058		
14	Total Disbursements for Expenses	4,257	$ 12,385	$ 289,995	23.41
May-2025					
15	Total Disbursements for Month	34,781	$ 47,440		
16	Total Disbursements for Expenses	4,049	$ 13,770	$ 597,078	43.36
June-2025					
17	Total Disbursements for Month	29,782	$ 46,699		
18	Total Disbursements for Expenses	4,127	$ 14,096	$ 499,028	35.40
July-2025					
19	Total Disbursements for Month	31,463	$ 57,790		
20	Total Disbursements for Expenses	4,523	$ 20,034	$ 1,249,027	62.35
August-2025					
21	Total Disbursements for Month	32,254	$ 46,003		
22	Total Disbursements for Expenses	4,224	$ 13,203	$ 391,825	29.68
September-2025					
23	Total Disbursements for Month	34,037	$ 80,893		
24	Total Disbursements for Expenses	3,958	$ 38,365	$ 941,232	24.53
25	Total Test Month Expense Disbursement	47,668	$ 194,681	$ 7,115,972	36.55

Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October-2024	37	$ 38,708	$ 521,883	13.48
2	November-2024	38	42,900	573,631	13.37
3	December-2024	42	61,187	1,434,065	23.44
4	January-2025	45	101,888	1,975,569	19.39
5	February-2025	42	73,452	1,791,212	24.39
6	March-2025	33	37,168	1,424,885	38.34
7	April-2025	35	39,413	1,421,523	36.07
8	May-2025	31	26,967	1,017,164	37.72
9	June-2025	32	22,772	833,747	36.61
10	July-2025	28	22,723	835,609	36.77
11	August-2025	27	20,780	750,436	36.11
12	September-2025	30	18,017	618,957	34.35
13	Total		$ 505,975	$ 13,198,681	
14	Purchase Gas Lag Days				26.09

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2026	Sch C-1			$ 3,980,967
2	Long-term Debt Ratio	Sch B-7			45.63%
3	Embedded Cost of Long-term Debt	Sch B-6			5.12%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 93,006
5	Daily Amount	L 4 / L 5 [2]	365		$ 255
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		57.37	
8	Interest Payment lag days	L 7 - L 6			(33.9)
9	Total Interest for Working Capital	L 5 * L 8			$ (8,634)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount 365
1	**FEDERAL INCOME TAX**				$ 54,071						
2	First Payment	01/15/26	04/01/26	76.00	$ 13,518	1,027,351					
3	Second Payment	03/15/26	04/01/26	17.00	13,518	229,802					
4	Third Payment	06/15/26	04/01/26	(75.00)	13,518	(1,013,833)					
5	Fourth Payment	09/15/26	04/01/26	(167.00)	13,518	(2,257,468)					
6	Total				$ 54,071	$ (2,014,148)	(37.25)	(57.37)	20.12	$ 1,087,748	$ 2,980
7	**STATE INCOME TAX**				$ 14,734						
8	First Payment	12/15/25	04/01/26	107.00	$ 3,683	394,127					
9	Second Payment	03/15/26	04/01/26	17.00	3,683	62,618					
10	Third Payment	06/15/26	04/01/26	(75.00)	3,683	(276,257)					
11	Fourth Payment	09/15/26	04/01/26	(167.00)	3,683	(615,132)					
12	Total				$ 14,734	(434,644)	(29.50)	(57.37)	27.87	$ 410,584	$ 1,125
13	**PA PROPERTY TAX**				$ 1,203						
14	First Payment	04/30/26	04/01/26	(29.00)	$ 602	(17,444)					
15	Second Payment	08/31/26	04/01/26	(152.00)	602	(91,428)					
16	Total				$ 1,203	(108,872)	(90.50)	(57.37)	(33.13)	$ (39,859)	$ (109)
17	**PURTA**				$ 1,291						
18	Payment	05/01/26	04/01/26	(30.00)	$ 1,291	(38,730)	(30.00)	(57.37)	27.37	$ 35,331	$ 97
19	Total Working Capital For Other Taxes										$ 4,093

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Miscellaneous	[6] Subscriptions	[7] Postage	[8] Rent	[9] Maintenance & Services
1	September, 2024		17,897	7,651	3,412	385	108	2	-	6,338
2	October		18,551	6,660	3,033	400	280	3	-	8,174
3	November		17,249	6,247	2,654	400	199	3	-	7,746
4	December, 2024		17,645	5,421	2,275	326	118	0	-	9,504
5	January, 2025		16,934	4,526	1,896	571	372	0	-	9,569
6	February		14,804	3,722	1,517	469	545	0	-	8,551
7	March		13,077	2,826	1,137	429	575	2	-	8,108
8	April		10,792	1,968	758	417	648	(3)	-	7,004
9	May		8,657	1,070	379	350	539	4	-	6,315
10	June		7,338	172	-	283	433	5	-	6,445
11	July		9,081	299	-	224	561	2	-	7,996
12	August		16,621	8,732	-	233	399	4	-	7,253
13	September, 2025		18,558	7,869	3,413	180	290	2	-	6,804
14	TOTAL		$ 187,204	$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
17	Monthly Average	13		$ 4,397	$ 1,575	$ 359	$ 390	$ 2	$ -	$ 7,677
18	Rate Case Amount		$ 14,400							

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule C-5
Witness: A. M. Keller
Page 1 of 1

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2024	$27,677
2	October	32,669
3	November	32,041
4	December, 2024	25,192
5	January, 2025	15,334
6	February	8,991
7	March	3,692
8	April	11,088
9	May	17,289
10	June	24,134
11	July	30,732
12	August	36,859
13	September, 2025	41,904
14	Total	$ 307,601
15	Number of Months	13
16	Average Monthly Balance	$ 23,662

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule C-6
Witness: D. T. Espigh
Page 1 of 1

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (700,643)	
2	Sub-total		(700,643)
3	ADIT on CIAC	38,965	
4	Sub-total		38,965
5	Federal ADIT		(661,678)
6	State Repair Regulatory Liability	(46,412)	(46,412)
7	CIAC Tax Gross-Up Regulatory Liability	(559)	(559)
8	Pro-Rata Adjustment	-	-
9	Balance At September 30, 2026		$ (708,649)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule C-7
Witness: A. M. Keller
Page 1 of 1

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2024	$ 20,721
2	October	$ 21,053
3	November	$ 21,369
4	December, 2024	$ 21,641
5	January, 2025	$ 22,111
6	February	$ 22,868
7	March	$ 24,005
8	April	$ 24,716
9	May	$ 24,801
10	June	$ 24,688
11	July	$ 24,591
12	August	$ 24,522
13	September, 2025	$ 24,475
14	Total	$ 301,560
15	Number of Months	13
16	Average Monthly Balance	$ 23,197

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule C-8
Witness: A. M. Keller
Page 1 of 1

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2024	$ 30,420
2	October	30,020
3	November	29,626
4	December, 2024	29,997
5	January, 2025	29,829
6	February	30,374
7	March	29,642
8	April	29,028
9	May	28,754
10	June	27,778
11	July	26,665
12	August	25,527
13	September, 2025	24,707
14	Total	$ 372,366
15	Number of Months	13
16	Average Monthly Balance	$ 28,644

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Pro Forma Test Year Rate Increase	[3] Pro Forma Test Year At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 763,512	$ -	$ 763,512
2	Gas Supply & Cost Adjustment Revenue		446,918	-	446,918
3	Other Revenues		14,181	-	14,181
4	Revenue Increase			42,743	42,743
5	Total operating revenues		1,224,611	42,743	1,267,354
	OPERATING EXPENSES				
6	Manufactured Gas		-	-	-
7	Gas Supply Production		403,778	-	403,778
8	Transmission		-		
9	Distribution		89,667	-	89,667
10	Customer Accounts		59,787	-	59,787
11	Uncollectible Expense	1.723%	23,275	736	24,011
12	Customer Information & Services		14,503	-	14,503
13	Sales		1,257	-	1,257
14	Administrative & General		106,682	-	106,682
15	Depreciation & Amortization		159,791	-	159,791
16	Taxes other than income taxes		13,430	-	13,430
17	Total operating expenses		872,170	736	872,907
18	Net operating income Before Income Tax		352,441	42,007	394,447
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		57,332		57,332
20	Pro Forma Income Tax on Revenue Increase			11,473	11,473
21	Net Income (loss)		$ 295,109	$ 30,533	$ 325,643

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates Budget For Year End 09/30/26	[3] Test Year At Present Rates Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates Pro Forma Adjusted For Test Year 9/30/26	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 804,333	$ (16,273)	$ 788,060		$ 788,060
2	Comm & Ind (N/NT)	481	294,701	(27,545)	267,156		267,156
3	Comm & Ind (DS)	489	35,926	(442)	35,484		35,484
4	Lg Transport/Other	489	99,227	(1,970)	97,257		97,257
5	Interruptible	489	21,992	482	22,473		22,473
6	Forfeited Discounts	487	6,261	-	6,261		6,261
7	Miscellaneous Service Revenues	488, 489.3, 495	4,781	847	5,628		5,628
8	Rent from Gas Properties	493	2,292	-	2,292		2,292
9	Rate Increase			-	-	42,743	42,743
10	Total operating revenues		1,269,512	(44,901)	1,224,611	42,743	1,267,354
	OPERATING EXPENSES						
11	Gas Production		-	-	-		-
12	Gas Supply Production		425,103	(21,325)	403,778		403,778
13	Transmission		-		-		
14	Distribution		89,214	452	89,667		89,667
15	Customer Accounts		59,816	(30)	59,787		59,787
16	Uncollectible Expense	1.723%	20,409	2,866	23,275	736	24,011
17	Customer Information & Services		14,764	(261)	14,503		14,503
18	Sales		1,250	8	1,257		1,257
19	Administrative & General		106,456	226	106,682		106,682
20	Depreciation & Amortization		153,978	5,813	159,791		159,791
21	Taxes other than income taxes		13,359	71	13,430		13,430
22	Total operating expenses		884,349	(12,179)	872,170	736	872,907
23	Net Operating Income - BIT		$ 385,163	$ (32,722)	$ 352,441	$ 42,007	$ 394,447

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab
Page 1 of 2

Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2]	[3]	[4]	[5]	[6] Adjustments	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Environmental Expense		Rate Case	Uncollectibles Expense			Sub-Total Adjustments	Total Proforma
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 460,036		$ (10,352)									$ (10,352)	$ 449,684
2	Comm & Ind (N/NT)	481	172,005		(12,004)									(12,004)	160,001
3	Comm & Ind (DS)	489	35,092		(8)									(8)	35,083
4	Lg Transport/Other	489	98,132		(1,861)									(1,861)	96,271
5	Interruptible	489	21,992		482									482	22,473
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	344,297		(5,921)									(5,921)	338,376
7	Comm & Ind (N/NT)	481	122,696		(15,541)									(15,541)	107,155
8	Comm & Ind (DS)	489	834		(433)									(433)	401
9	Lg Transport/Other	489	1,095		(109)									(109)	986
10	Interruptible Transport	489	-		-									-	-
11	Forfeited Discounts	487	6,261		-									-	6,261
12	Miscellaneous Service Revenues	488, 489.3, 495	4,781		847									847	5,628
13	Rent from Gas Properties	493	2,292		-									-	2,292
14			-											-	-
15	Total operating revenues		1,269,512		(44,901)	-	-	-	-	-	-	-	-	(44,901)	1,224,611
	OPERATING EXPENSES														-
16	Gas Production		-				-							-	-
17	Gas Supply Production		425,103			(21,325)								(21,325)	403,778
18	Transmission		-												-
19	Distribution		89,214	-			452						-	452	89,667
20	Customer Accounts		59,816				192							192	60,009
21	Uncollectible Expense		20,409								2,866			2,866	23,275
22	Customer Information & Services		14,764				13						-	13	14,777
23	Sales		1,250				8							8	1,257
24	Administrative & General		106,456	-			226	-	-	-		-		226	106,682
25	Depreciation & Amortization		153,978											-	153,978
26	Taxes other than income taxes		13,359											-	13,359
														-	-
27	Total operating expenses		$ 884,349	$ -	$ -	$ (21,325)	$ 891	$ -	$ -	$ -	$ 2,866	$ -	$ -	$ (17,568)	$ 866,782
28	Net operating income Before Income Tax		$ 385,163	$ -	$ (44,901)	$ 21,325	$ (891)	$ -	$ -	$ -	$ (2,866)	$ -	$ -	$ (27,334)	$ 357,829

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments	[4] Other Adjustments	[5] Universal Service	[6] Adjustments	[7]	[8] EE&C Program	[9]	[10] Depreciation	[11] Taxes Other Than Income	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES			D-14	D-15	D-16	D-17	D-18	D-19		D-21	D-31		
	Customer & Distribution Revenue													
29	Residential (R/RT)	$ 449,684												$ 449,684
30	Comm & Ind (N/NT)	160,001												160,001
31	Comm & Ind (DS)	35,083												35,083
32	Lg Transport/Other	96,271												96,271
33	Interruptible	22,473												22,473
	Revenue for Cost of Gas													-
34	Residential (R/RT)	338,376												338,376
35	Comm & Ind (N/NT)	107,155												107,155
36	Comm & Ind (DS)	401												401
37	Lg Transport/Other	986												986
38	Interruptible Transport	-												-
39	Forfeited Discounts	6,261												6,261
40	Miscellaneous Service Revenues	5,628												5,628
41	Rent from Gas Properties	2,292												2,292
42	-	-												-
43	Total operating revenues	1,224,611	-	-	-	-	-	-	-	-	-	-	-	1,224,611
	OPERATING EXPENSES													
44	Gas Production	-												-
45	Gas Supply Production	403,778												403,778
46	Transmission	-												-
47	Distribution	89,667					-	-						89,667
48	Customer Accounts	60,009			-	(222)								59,787
49	Uncollectible Expense	23,275												23,275
50	Customer Information & Services	14,777							(274)					14,503
51	Sales	1,257			-									1,257
52	Administrative & General	106,682		-	-									106,682
53	Depreciation & Amortization	153,978									5,813			159,791
54	Taxes other than income taxes	13,359										71		13,430
55	Total operating expenses	$ 866,782	$ -	$ -	$ -	$ (222)	$ -	$ -	$ (274)	$ -	$ 5,813	$ 71	$ -	$ 872,170
56	Net operating income Before Income Tax	$ 357,829	$ -	$ -	$ -	$ 222	$ -	$ -	$ 274	$ -	$ (5,813)	$ (71)	$ -	$ 352,441

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-5
Witness: S. A. Epler
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Adjustment - Revenue Adjustments

Line #	Description	Reference Or Account Number	[1] 2026 Budget	[2] PRO FORMA ADJUSTMENTS Other Adjustments	[3] Rev/PGC Adj Annualization	[4] Total Proforma Adjustments	[5] Proforma Adjusted At Present Rates
						D-5A	
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 460,036	$ (10,352)		$ (10,352)	$ 449,684
2	Comm & Ind (N/NT)	481	172,005	(12,004)		(12,004)	160,001
3	Comm & Ind (DS)	489	35,092	(8)		(8)	35,083
4	Lg Transport/Other	489	98,132	(1,861)		(1,861)	96,271
5	Interruptible	489	21,992	482		482	22,473
6	Cust Chg & Distrib Revenue		787,256	(23,744)	-	(23,744)	763,512
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	344,297	248	(6,169)	(5,921)	338,376
8	Comm & Ind (N/NT)	481	122,696	(385)	(15,156)	(15,541)	107,155
9	Comm & Ind (DS)	489	834	(433)		(433)	401
10	Lg Transport/Other	489	1,095	(109)		(109)	986
11	Interruptible Transport	489	-	-		-	-
12	Revenue for Cost of Gas		468,922	(680)	(21,325)	(22,005)	446,918
							-
13	Total Customer Revenue		1,256,178	(24,424)	(21,325)	(45,748)	1,210,430
14	Forfeited Discounts	487	6,261		-	-	6,261
15	Miscellaneous Service Revenues	488 & 489.3	3,178		-	-	3,178
16	Rent from Gas Properties	493	2,292		-	-	2,292
17	Other Revenues	495	1,603	847		847	2,450
18	TOTAL REVENUES		$ 1,269,512	$ (23,577)	$ (21,325)	$ (44,901)	$ 1,224,611

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-5A
Witness: S. A. Epler
Page 1 of 1

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 804,333	$ 788,060	$ (16,273)	
2	Comm & Ind (N/NT)		294,701	267,156	(27,545)	
3	Comm & Ind (DS)		35,926	35,484	(442)	
4	Lg Transport/Other		99,227	97,257	(1,970)	
5	Interruptible		21,992	22,473	482	
6	Total		$ 1,256,178	$ 1,210,430	$ (45,748)	$ (45,748)
COST OF COMMODITY						
7	Residential (R/RT)		$ 344,297	338,376	$ (5,921)	
8	Comm & Ind (N/NT)		122,696	107,155	(15,541)	
9	Comm & Ind (DS)		834	401	(433)	
10	Lg Transport/Other		1,095	986	(109)	
11	Interruptible		0	0	0	
12	Total		$ 468,922	$ 446,918	$ (22,005)	$ (22,005)
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 460,036	$ 449,684	$ (10,352)	
14	Comm & Ind (N/NT)		172,005	160,001	(12,004)	
15	Comm & Ind (DS)		35,092	35,083	(8)	
16	Lg Transport/Other		98,132	96,271	(1,861)	
17	Interruptible		21,992	22,473	482	
18	Total		$ 787,256	$ 763,512	$ (23,744)	$ (23,744)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-5B
Witness: D. T. Espigh
Page 1 of 1

Adjustment - Amortization of Tax Gross-up on CIAC for Interconnects

Line #	Description	[1] Factor Or Reference	[2] Other Adjustments	[3] Total
1	Amortization of Tax Gross-up		$ 847	$ 847
2	Total ProForma Adjustment			$ 847

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-6
Witness: S. A. Epler
Page 1 of 1

Adjustment - Gas Costs

Line #	Description	[1] Budgeted Gas Costs	[2] PRO FORMA ADJUSTMENTS D-5A Gas Costs	[3]	[4] Gas Cost Pro Forma Adjustments	[5] Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 425,103			$ -	$ 425,103
2	Residential (R/RT)		(6,169)		(6,169)	(6,169)
3	Comm & Ind (N/NT)		(15,156)		(15,156)	(15,156)
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 425,103	$ (21,325)	$ -	$ (21,325)	$ 403,778

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-7
Witness: T. A. Hazenstab

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/26	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	27,867	-	27,867	322	28,189
5	Customer Account Operations Expenses	16,653	-	16,653	192	16,846
6	Total Cust. Service & Inform. Operations Exp	1,101	-	1,101	13	1,114
7	Total Operation Sales Expenses	677	-	677	8	684
8	Total A & G Operation Expenses	18,708	-	18,708	216	18,924
9	Total Operations	65,006	-	65,006	751	65,757
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	11,304	-	11,304	131	11,434
14	Total A&G Maintenance	862	-	862	10	872
15	Total Maintenance	12,165	-	12,165	141	12,306
16	Total Payroll to Expense	$ 77,172	$ -	$ 77,172	$ 891	$ 78,063
17	Percent Increase					1.155%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-7
Witness: T. A. Hazenstab
Page 2 of 2

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union At 6-1	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-26		$ 33,262	$ 17,465	$ 26,445	$ 77,172
	Annualize for Wage Increase to 9-30-26					
2	Percent Increase		4.00%	4.00%	4.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/26	67%			
4	Non-Exempt Annualization Factor	10/1/25		0%		
5	Exempt Annualization Factor	10/1/25			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	891	0	0	$ 891
7	Annualized Salaries & Wages at 9-30-26 Rates	L 1 + L 6	$ 34,153	$ 17,465	$ 26,445	
8	Adjustments from Schedule D-9				$ -	
9	Pro Forma Salaries & Wages for TY		$ 34,153	$ 17,465	$ 26,445	
10	Pro Forma Adjustment to S&W					$ 891
11	Annualization Factor	L 10 / L 1				1.155%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-11
Witness: V. K. Ressler
Page 1 of 1

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2]/[3]	[5] Total [2]/[3]
Adjustment #1:						
1	2023		$ 23,142	$ 1,210,517	1.91%	
2	2024		$ 17,089	$ 1,020,566	1.67%	
3	2025		$ 17,879	$ 1,140,677	1.57%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 19,370	$ 1,123,920		1.723%
5	2026 Budget				$ 18,098	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.723%		$ 1,216,691		
7	Pro Forma at Present Rate Revenue	[1] * [3]			20,964	
8	Total for Test Year					$ 2,866

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-16
Witness: S. A. Epler
Page 1 of 1

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase for Pro Forma TY Universal Service Expense	Pro Forma
		Budget
1	Customer Assistance Plan Credit	$ 22,669
2	Administration Costs	1,421
3	LIURP	4,468
4	Hardship Program (Project Share)	32
5	Customer Assistance Plan Pre-program Arrearage	2,879
6	TOTAL	$ 31,469
7	Adjusted Budget	$ 31,247
8	Adjustment	$ (222)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-19
Witness: S. A. Epler
Page 1 of 1

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2026 Original Program Costs	$ 12,270	
2	Adjusted Budget	$ 11,996	
3	Additional Expense Adjustment (Line 2 - Line 1)		(274)
4	Total Adjustment		$ (274)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-21
Witness: J.F. Weidmayer

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/26 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
					-
17	TOTAL PRODUCTION & GATHERING		-	-	-
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	(23)	23	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		(23)	23	-

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/26 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	11	(0)	11
32	Structures & Improvements	366	0	0	0
33	Mains	367	391	13	403
34	Measuring & Regulating Station Equipment	369	92	(4)	89
35	Communication Equipment	370	92	(10)	81
36	Other Equipment	371	6	(0)	5
37	TOTAL TRANSMISSION		592	(2)	590
DISTRIBUTION PLANT					
38	Land & Land Rights	374	42	0	43
39	Structures & Improvements	375	217	(68)	148
40	Mains	376	47,725	(181)	47,544
41	Measuring & Regulating Station Equipment	378	5,471	(325)	5,146
42	Measuring & Regulating Station Equipment	379	2,060	276	2,336
43	Services	380	52,457	(4,720)	47,738
44	Meters	381	6,476	971	7,447
45	Meter Installations	382	3,128	419	3,547
46	House Regulators	383	1,218	(945)	273
47	House Regulatory Installations	384	351	(24)	326
48	Industrial Measuring & Reg. Station Equipment	385	911	(116)	795
49	Other Property	386	25	3	28
50	Other Equipment	387	92	0	92
51	TOTAL DISTRIBUTION		120,173	(4,710)	115,463
GENERAL PLANT					
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	7,599	839	8,438
54	Office Furniture & Equipment	391	24,305	2,212	26,518
55	Transportation Equipment	392	5,952	1,245	7,197
56	Stores Equipment	393	1	0	1
57	Tools & Garage Equipment	394	2,309	24	2,333
58	Laboratory Equipment	395	22	0	22
59	Power Operated Equipment	396	915	(34)	881
60	Communication Equipment	397	145	179	324
61	Miscellaneous Equipment	398	272	(210)	62
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		41,519	4,256	45,776
64	TOTAL DEPRECIATION		$ 162,262	$ (433)	$ 161,829
65	CHARGED TO CLEARING ACCOUNTS		$ (9,320)	$ (1,415)	$ (10,735)
66	NET SALVAGE AMORTIZATION		$ 9,205	$ (508)	$ 8,698

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-31
Witness: T. A. Hazenstab
Page 1 of 1

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Budget Amounts 9/30/26	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/26
1	PURTA Taxes	408.1		$ 1,291	$ -	$ 1,291
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		1,203	-	1,203
4	Social Security	408.1	D-32	5,832	67	5,899
5	FUTA	408.1	D-32	7	-	7
6	SUTA	408.1	D-32	361	4	365
7	PUC Assessment	408.1		4,665	-	4,665
8	Total			$ 13,359	$ 71	$ 13,430

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-32
Witness: T. A. Hazenstab
Page 1 of 1

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/26 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 77,172	$ 891	
2	FICA Expense		5,832		
3	FICA Expense - Percent	L 2 / L 1	7.56%	7.56%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 67
5	FUTA Expense		7		
6	FUTA Expense - Percent	L 5 / L 1	0.01%	0.01%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		361		
9	SUTA Expense - Percent	L 8 / L 1	0.47%	0.47%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			4
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 71

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-33
Witness: D. T. Espigh
Page 1 of 1

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,224,611	$ 42,743	$ 1,267,354
2	Operating Expenses			(872,170)	(736)	(872,907)
3	OIBIT	L 1 + L 2		352,441	42,007	394,447
	Interest Expense					
4	Rate Base	Sch A-1	3,980,967			
5	Weighted Cost of Debt	Sch B-7	0.02340			
6	Synchronized Interest Expense	L 4 * L 5		(93,155)	-	(93,155)
7	Base Taxable Income	L 3 + L 6		259,286	42,007	301,292
8	Total State Tax Depreciation	Sch D-34	$ 327,451			
9	Pro Forma State Book Depreciation	Sch D-34	166,350			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(161,101)		(161,101)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 98,185	$ 42,007	$ 140,191
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	7.99%	$ (7,845)	$ (3,356)	$ (11,201)
14	Total Federal Tax Depreciation	Sch D-34	$ 309,680			
15	Pro Forma Federal Book Depreciation	Sch D-34	166,350			
16	Federal Tax Deducts (Over) Under Book	L 15 - L 14		(143,330)	-	(143,330)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		108,111	38,650	146,761
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(22,703)	(8,117)	(30,820)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(30,548)	(11,473)	(42,021)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 161,829			
22	Total Tax Depreciation	L 15 - Sch D-34 L 2	300,475			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		138,646	-	138,646
24	Deferred Federal Taxable Income	L 23		$ 138,646	$ -	$ 138,646
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(23,936)	-	(23,936)
	Deferred State Income Taxes					
26	Repairs			(3,218)		(3,218)
27	CIAC			(315)		(315)
28	State Deferred Income Tax (Expense)/Refund			(3,532)	-	(3,532)
29	Net Income Tax Expense	L20 + L 25 + L28		(58,016)	(11,473)	(69,489)
	Other Tax Adjustments					
30	ITC			684		684
31	Combined Income Tax Expense	L 29 + L 30		$ (57,332)	$ (11,473)	$ (68,805)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (45,954)	$ (8,117)	$ (54,071)
33	State Income Tax Expense	L 13 + L 28		(11,377)	(3,356)	(14,734)
34	Total Income Tax Expense	L 32 + L 33		$ (57,332)	$ (11,473)	$ (68,805)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Gas Division | **Schedule** | **D-34**
Before the Pennsylvania Public Utility Commission | **Witness:** | **D. T. Espigh**
Future Period - 12 Months Ended September 30, 2026 | **Page 1 of 1**
($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 220,859	
2	Cost of Removal		9,205	
3	Repairs Tax Deduction		102,616	
4	Other Tax Basis Adjustments		(23,000)	
5	Total Federal Accelerated Tax Depreciation			$ 309,680
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		17,771	
7	Total State Accelerated Tax Depreciation			$327,451
	Straight Line Tax Depreciation			
8	Gas Plant		$ 161,829	
9	Total Tax Depreciation			$ 161,829
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 161,829	
11	Net Salvage Amortization		8,698	
12	Depreciation Charged to Clearing Accounts	(10,735)		
13	Estimated Percent of Clearing Charged to CWIP	39%		
14	Depreciation Charged to CWIP		(4,176)	
15	Book Depreciation for Tax Calculation			$ 166,350

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2026
($ in Thousands)

Schedule D-35
Witness: T. A. Hazenstab
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Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.017230)
3	NET REVENUES	Sum L 1 to L 2		0.982770
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	7.9900%	(0.078523)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.904247
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.189892)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.714355
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.399864
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		26.842%
INCOME TAX FACTOR				
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	7.9900%	(0.079900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.920100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.193221)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.726879
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.375745
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		27.312%

UGI GAS

EXHIBIT A

HISTORIC

Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)
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	Retirements	A. M. Keller
C-3	Accumulated Provision for Depreciation	A. M. Keller
	Summary of Accumulated Depreciation	A. M. Keller
	Accumulated Depreciation by FERC Account	A. M. Keller
	Cost of Removal	A. M. Keller
	Negative Net Salvage Amortization	A. M. Keller
	Salvage	A. M. Keller
C-4	Working Capital	A. M. Keller
	Summary of Working Capital	A. M. Keller
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	Summary of Expense Lag Calculations	A. M. Keller
	General Disbursements Payment Lag Summary	A. M. Keller
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C-5	Gas Inventory	A. M. Keller
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C-7	Customer Deposits	A. M. Keller
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Historic Period - 12 Months Ended September 30, 2025

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D-3	Summary of Pro Forma Adjustments	T. A. Hazenstab
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D-5	Adjustment - Revenue Adjustments	S. A. Epler
D-5A	Adjustment - Test Year Revenue Changes	S. A. Epler
D-5B	SCHEDULE NOT USED	N/A
D-6	Adjustment - Gas Costs	S. A. Epler
D-7	Adjustment - Salaries & Wages	T. A. Hazenstab
D-8	SCHEDULE NOT USED	N/A
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D-10	SCHEDULE NOT USED	N/A
D-11	Adjustment - Uncollectibles	V. K. Ressler
D-12	SCHEDULE NOT USED	N/A
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D-14	SCHEDULE NOT USED	N/A
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D-16	SCHEDULE NOT USED	N/A
D-17	SCHEDULE NOT USED	N/A
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D-19	SCHEDULE NOT USED	N/A
D-21	Adjustment - Depreciation expense	J.F. Weidmayer
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D-32	Adjustment - Payroll Taxes	T. A. Hazenstab
D-33	Income Tax Calculation	D. T. Espigh
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D-35	Gross Revenue Conversion Factor	T. A. Hazenstab

UGI Utilities, Inc. - Gas Division | **Schedule** | **A-1**
Before the Pennsylvania Public Utility Commission | **Witness:** | **T. A. Hazenstab**
Historic Period - 12 Months Ended September 30, 2025 | **Page 1 of 1**
($ in Thousands)

Summary of Measure of Value and Revenue Increase

Line #	Description	Function	Reference Section	Pro Forma Test Year Ended September 30, 2025 At Present Rates	Increase	Proposed Rates
		[1]	[2]	[3]	[4]	[5]
RATE BASE						
1	Utility Plant		C-2	$ 5,797,706		$ 5,797,706
2	Accumulated Depreciation		C-3	(1,519,282)		(1,519,282)
3	Net Plant in service	L 1 + L 2		4,278,424	-	4,278,424
4	Working Capital		C-4	66,613		66,613
5	Gas Inventory		C-5	23,662		23,662
6	Accumulated Deferred Income Taxes		C-6	(681,366)		(681,366)
7	Customer Deposits		C-7	(23,197)		(23,197)
8	Materials & Supplies		C-8	28,644		28,644
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 3,692,780	$ -	$ 3,692,780
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 744,880	$ 35,831	$ 780,711
11	Gas Cost Revenue		D-5	418,750		418,750
12	Other Operating Revenues		D-5	12,240		12,240
13	Total Revenues	Sum L 10 to L 12		1,175,870	35,831	1,211,701
14	Operating Expenses		D-1	(857,885)	(617)	(858,502)
15	OIBIT	L 13 + L 14		317,986	35,214	353,199
16	Pro Forma Income Tax at Present Rates		D-33	(51,712)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(9,757)	(61,469)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 266,273	$ 25,457	$ 291,730
19	RATE OF RETURN	L 18 / L 9		7.2106%		7.9000%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		7.2106%		
21	Rate of Return Required		B-7	7.9000%		
22	Change in ROR	L 21 - L 20		0.6894%		
23	Change in Operating Income	L 22 * L 9		$ 25,457		
24	Gross Revenue Conversion Factor		D-35	1.407513		
25	Change in Revenues	L 23 * L 24		$ 35,831		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, Col 3			4.81%	
27	Percent Increase -- Total Revenues	L 25 / L 13, Col 3			3.05%	

Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-25
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 5,791,689
2	Other Utility Plant	-
3	Total Plant In Service	5,791,689
4	Construction Work In Progress (107)	99,469
5	Total Utility Plant	5,891,159
6	Accumulated Provision for Depreciation - Gas (108)	(1,519,099)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	4,554,205
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	714
11	Accumulated Depreciation on NUP (122)	(204)
12	Investment in Associated & Subsidiary Companies (123.1)	1,168
13	Other Investments (124)	15
14	Total Other Property and Investments	1,693
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	14,498
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	93,607
18	Other Accounts Receivable (143)	17,446
19	Accum Provision for Uncollectible (144)	(14,075)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	16,596
22	Plant Materials & Operating Supplies (154)	22,844
23	Stores Expense - Undistributed (163)	2,585
24	Gas Stored - Current (164.1)	41,904
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	19,598
27	Accrued Utility Revenues (173)	20,322
28	Miscellaneous Current & Accrued Assets (174)	2
29	Derivative Instrument Assets (175)	2,184
30	Total Current and Accrued Assets	237,512
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	7,131
32	Other Regulatory Assets (182.3)	490,735
33	Other Preliminary Survey & Investigation Charges (183.2)	53
34	Clearing Accounts (184)	0
35	Miscellaneous Deferred Debits (186)	28,299
36	Deferred Losses from Disposition of Utility Plant (187)	1
37	Unamortized Loss on Reacquired Debt (189)	-
38	Accumulated Deferred Income Taxes (190)	-
39	Unrecovered Purchase Gas Costs (191)	15,630
40	Total Deferred Debits	541,849
41	TOTAL ASSETS AND OTHER DEBITS	$ 5,335,258

Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-25
	PROPRIETARY CAPITAL	
42	Common Stock Issued (201)	$ 53,926
43	Preferred Stock Issued (204)	-
44	Premium on Capital Stock (207)	523,580
45	Capital Stock Expense (214)	-
46	Retained Earnings (215, 215.2, 216)	1,391,660
47	Accum Other Comprehensive Income (219)	(11,489)
48	Total Proprietary Capital	1,957,678
	LONG TERM DEBT	
49	Bonds (221)	-
50	Advances from Associated Companies (223)	-
51	Other Long-Term Debt (224)	1,690,869
52	Unamortized Premium on LTD (225)	-
53	Unamortized Discount on LTD (226)	-
54	Total Long-term Debt	1,690,869
	OTHER NON-CURRENT LIABILITIES	
55	Obligations under Capital Leases (227)	182
56	Accum. Prov for Injuries & Damages (228.2)	2,103
57	Accum. Prov for Pensions & Benefits (228.3)	9,950
58	Accum. Miscellaneous Operating Prov (228.4)	61,276
59	Asset Retirement Obligation (230)	111
60	Total Non-Current Liabilities	73,621
	CURRENT & ACCRUED LIABILITIES	
61	Notes Payable (231)	294,169
62	Accounts Payable (232)	53,981
63	Notes Payable to Assoc. Companies (233)	-
64	Accounts Payable to Assoc. Cos (234)	17,808
65	Customer Deposits (235)	24,483
66	Taxes Accrued (236)	(2,371)
67	Interest Accrued (237)	20,131
68	Tax Collections Payable (241)	116
69	Misc Current & Accrued Liabilities (242)	79,043
70	Obligations Under Capital Leases (243)	504
71	Derivative Instrument Liabilities (244)	6,982
72	Total Current & Accrued Liabilities	494,845
	OTHER DEFERRED CREDITS	
73	Customer Advances for Construction (252)	-
74	Other Deferred Credits (253)	28,617
75	Other Regulatory Liabilities (254)	269,453
76	Deferred ITC (255)	791
77	Accumulated Deferred Income Taxes (282)	766,835
78	Accumulated Deferred Income Taxes (283)	52,548
79	Total Other Deferred Credits	1,118,244
80	TOTAL LIABILITIES & OTHER CREDITS	$ 5,335,258

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule B-2
Witness: T. A. Hazenstab

Statement of Net Utility Operating Income

Line No	Description	[1] Actual TYE 9-30-25	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 1,137,255	B-3
2	Other Operating Revenues	12,240	B-3
3	Total Revenues	1,149,495	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	652,505	B-4 & D-2
5	Depreciation & Amortization Expense	148,285	D-21
6	Taxes Other Than Income Taxes	12,556	B-5
7	Total Operating Expenses	813,346	
8	Operating Income Before Income Taxes (OIBIT)	336,150	
	Income Taxes:		
9	State	10,250	B-5
10	Federal	41,462	B-5
11	Total Income Taxes	51,712	
12	**Net Utility Operating Income**	$ 284,437	

Statement of Operating Revenues

Line No	Description	[1] Actual TYE 9-30-25
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 693,337
2	Comm & Ind (N/NT) (481)	257,448
3	Comm & Ind (DS) (489)	50,460
4	Lg Transport/Other (489)	107,266
5	Interruptible (489)	28,746
6	Sub-Total Gas Operating Revenues	1,137,255
	Other Operating Revenues	
7	Forfeited Discounts (487)	5,460
8	Miscellaneous Service Revenues (488)	3,694
9	Rent from Gas Properties (493)	2,106
10	Other Revenues (495)	980
11	Sub-Total Other Operating Revenues	12,240
12	**Total Operating Revenues**	$ 1,149,495

UGI Utilities, Inc. - Gas Division | **Schedule B-4**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Historic Period - 12 Months Ended September 30, 2025 | **Page 1 of 3**
($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-25
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	-
3	Total Gas Raw Materials Expenses		-
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	466,841
16	Liquefied Natural Gas Purchases	804.1	311
17	Other Gas Purchases	805.0	1,171
18	Purchases Gas Cost Adjustments	805.1	(102,299)
19	Gas Withdrawn from Storage-Debit	808.1	36,491
20	Purchased Gas Expenses	807.0	-
21	Gas Used for Other Utility Operations-Credit	812.0	(2,264)
22	Gas Delivered to Storage-Credit	808.2	(49,027)
23	Other Gas Supply Expenses	813.0	24,629
24	Gas Supply Operation Expenses		375,853
	Underground Storage Expense - Operation		
25	Operation Supervision and Engineering	814	-
26	Maps and Records	815	-
27	Wells Expenses	816	-
28	Lines Expenses	817	-
29	Measuring and Regulating Station Expenses	820	-
30	Purification Expenses	821	-
31	Gas Losses	823	-
32	Other Expenses	824	-
33	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
34	Maintenance Supervision and Engineering	830	-
35	Maintenance of Structures and Improvements	831	-
36	Maintenance of Reservoirs and Wells	832	-
37	Maintenance of Lines	833	-
38	Maintenance of Measuring & Regulating Station Equip.	835	-
39	Total Underground Maintenance Expenses		-

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-25
	Transmission Expense - Operations		
40	Operating Supervision and Engineering	850	-
41	System Control and Load Dispatching	851	-
42	Communication System Expenses	852	-
43	Mains Expenses	856	-
44	Measuring and Regulating Station Expenses	857	-
45	Other Expenses	859	-
46	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
47	Maintenance Supervision and Engineering	861	-
48	Maintenance of Structures and Improvements	862	-
49	Maintenance of Mains	863	-
50	Maintenance of Measuring and Regulating Station Equip.	865	-
51	Maintenance of Communication Equipment	866	-
52	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
53	Operation Supervision and Engineering	870	5,077
54	Distribution Load Dispatching	871	2,544
55	Compressor Station Fuel and Power (Major Only)	873	-
56	Mains and Services Expenses	874	29,397
57	Measuring and Regulating Station Expenses-General	875	2,225
58	Measuring and Regulating Station Expenses-Industrial	876	105
59	Measuring and Regulating Station Expenses-City Gate	877	435
60	Meter and House Regulator Expenses	878	3,476
61	Customer Installations Expenses	879	2,358
62	Other Expenses	880	9,545
63	Rents	881	638
64	Total Distribution Operation Expenses		55,800
	Distribution Expense - Maintenance		
65	Maintenance Supervision and Engineering	885	2,414
66	Maintenance of Structures and Improvements	886	-
67	Maintenance of Mains	887	23,934
68	Maintenance of Compressor Station Equipment	888	-
69	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	2,780
70	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	4,082
71	Maintenance of Measuring & Reg. Station Equip.-City G	891	102
72	Maintenance of Services	892	988
73	Maintenance of Meters & House Regulators	893	20
74	Maintenance of Other Equipment	894	1,555
75	Construction & Maintenance	895	-
76	Total Distribution Maintenance Expenses		35,876
	Customer Accounts Expense - Operations		
77	Supervision	901	834
78	Meter Reading Expenses	902	3,059
79	Customer Records & Collection Expenses	903	50,143
80	Uncollectable Accounts	904	16,582
81	Miscellaneous Customer Accounts Expenses	905	64
82	Total Administrative & General		70,683

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-25
	Customer Service & Information Expense		
83	Supervision	907	83
84	Customer Assistance Expenses	908	932
85	Informational & Instructional Advertising Expenses	909	879
86	Miscellaneous Customer Service & Informational Exp.	910	11,995
87	Total Cust. Service & Inform. Operations Exp		13,890
	Sales Expense		
88	Supervision	911	-
89	Demonstrating and Selling Expenses	912	670
90	Advertising Expenses	913	709
91	Miscellaneous Sales Expenses	916	-
92	Total Operation Sales Expenses		1,378
	Administrative & General - Operations		
93	Administrative and General Salaries	920.0	23,716
94	Office Supplies and Expenses	921.0	18,422
95	Outside Service Employed	923.0	27,416
96	Property Insurance	924.0	337
97	Injuries and Damages	925.0	10,013
98	Employee Pensions and Benefits	926.0	13,271
99	Regulatory Commission Expenses	928.0	36
100	General Advertising Expenses	930.1	154
101	Miscellaneous General Expenses	930.2	1,551
102	Rents	931.0	50
103	Total A & G Operation Expenses		94,965
	Administrative & General - Maintenance		
104	A&G Maintenance of General Plant	932	4,064
105	A&G Maintenance of General Plant	935	-
106	Total A & G Maintenance Expenses		4,064
107	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 652,509
108	Total Gas Operation Expenses		612,569
109	Total Gas Maintenance Expense		39,940
110	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 652,509

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule B-5
Witness: T. A. Hazenstab

Detail of Taxes

Line No	Description	Reference	[1] Actual TYE 9-30-25
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 1,254
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	890
4	PUC Assessment	D-31	4,552
5	Subtotal		6,696
	Payroll Taxes		
6	FICA	D-31	5,435
7	SUTA	D-31	355
8	FUTA	D-31	70
9	Other	D-31	-
10	Subtotal		5,860
11	Total Taxes Other Than Income Taxes		$ 12,556
	Income Taxes		
12	State		$ 10,250
13	Federal		41,462
14	Total Income Taxes		$ 51,712

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4]*[5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	1.07%	6.56%	0.07%
2	6.133%	10/14/2004	10/15/2034	20,000	1.07%	6.19%	0.07%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	5.36%	6.32%	0.34%
4	4.980%	3/26/2014	3/26/2044	175,000	9.38%	5.00%	0.47%
5	2.950%	6/30/2016	6/30/2026	100,000	5.36%	3.92%	0.21%
6	4.120%	9/30/2016	9/30/2046	200,000	10.71%	5.01%	0.54%
7	4.120%	10/31/2016	10/31/2046	100,000	5.36%	4.28%	0.23%
8	4.550%	2/1/2019	2/1/2049	150,000	8.04%	4.58%	0.37%
9	3.120%	3/19/2020	4/16/2050	150,000	8.04%	3.15%	0.25%
10	1.590%	6/15/2021	6/15/2026	100,000	5.36%	1.73%	0.09%
11	1.640%	9/15/2021	9/15/2026	75,000	4.02%	1.75%	0.07%
12	4.750%	7/15/2022	7/15/2032	90,000	4.82%	4.82%	0.23%
13	4.990%	9/15/2022	9/15/2052	85,000	4.55%	5.03%	0.23%
14	6.100%	11/30/2023	11/30/2033	150,000	8.04%	6.17%	0.50%
15	6.400%	11/30/2023	11/30/2053	75,000	4.02%	6.43%	0.26%
16	6.020%	11/30/2023	11/30/2030	25,000	1.34%	6.11%	0.08%
17	5.240%	11/14/2024	11/30/2029	50,000	2.68%	5.38%	0.14%
18	5.520%	11/14/2024	11/30/2034	125,000	6.70%	5.60%	0.38%
Term Loan							
19	3.917%	10/31/2017	7/12/2027	76,563	4.10%	3.96%	0.16%
20	Total Long-Term Debt			$ 1,866,563	100.00%		4.69%
21	Total Long-Term Debt			$ 1,866,563	100.00%	4.69%	4.69%
22	Total Short-Term Debt				0.00%		0.00%
23	TOTAL			$ 1,866,563	100.00%		
24	Weighted Cost of Debt						4.69%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule B-7
Witness: D. W. D'Ascendis

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	47.10%	4.69%	B-6	2.21%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	52.90%	10.75%		5.69%
4	Total	100.00%			7.90%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-1
Witness: A. M. Keller
Page 1 of 1

Measure of Value

Line #	Description	[1] Reference Schedule	[2] # of Pages	[3] Pro Forma Test Year Ended September 30, 2025 At Present Rates	[4] Adjustments	[5] Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 5,797,706		$ 5,797,706
2	Accumulated Depreciation	C-3	11	(1,519,282)		(1,519,282)
3	Net Plant in service			4,278,424	-	4,278,424
4	Working Capital	C-4	9	66,613		66,613
5	Gas Inventory	C-5	1	23,662		23,662
6	Accumulated Deferred Income Taxes	C-6	1	(681,366)		(681,366)
7	Customer Deposits	C-7	1	(23,197)		(23,197)
8	Materials & Supplies	C-8	1	28,644		28,644
9	TOTAL MEASURE OF VALUE			$ 3,692,780	$ -	$ 3,692,780

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-2
Witness: A. M. Keller
Page 1 of 9

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] HTY 9-30-25
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] HTY 9-30-25
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,468
34	Measuring & Regulating Station Equipment	369	6,173
35	Communication Equipment	370	3,505
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,575
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,638
39	Structures & Improvements	375	7,181
40	Mains	376	2,752,176
41	Measuring & Regulating Station Equipment	378	164,221
42	Measuring & Regulating Station Equipment	379	81,780
43	Services	380	1,684,481
44	Meters	381	192,839
45	Meter Installations	382	141,912
46	House Regulators	383	10,274
47	House Regulatory Installations	384	17,829
48	Industrial Measuring & Reg. Station Equipment	385	40,449
49	Other Property	386	1,274
50	Other Equipment	387	6,799
51	TOTAL DISTRIBUTION		5,112,854
	GENERAL PLANT		
52	Land & Land Rights	389	13,523
53	Structures & Improvements	390	207,766
54	Office Furniture & Equipment	391	281,626
55	Transportation Equipment	392	66,908
56	Stores Equipment	393	16
57	Tools & Garage Equipment	394	44,808
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	13,798
60	Communication Equipment	397	3,095
61	Miscellaneous Equipment	398	1,510
62	Other Tangible Property	399	16
63	TOTAL GENERAL		633,504
64	Total Plant		$ 5,797,706

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Historic Test Year 09/30/25	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	-	-	-
4	Transmission Plant	Sch C-2, Page 5	50,575	-	50,575
5	Distribution Plant	Sch C-2, Page 5	5,112,854	-	5,112,854
6	General Plant	Sch C-2, Page 5	633,504	-	633,504
7	Other Plant		-	-	-
8	Total Utility Plant		$ 5,797,706	$ -	$ 5,797,706

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Historic Test Year 2025	[3] Pro Forma Adjustment	[4] Balance
INTANGIBLE PLANT					
1	Organization	301	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	-	194
3	Miscellaneous Intangible Plant	303	290	-	290
4	TOTAL INTANGIBLE		774	-	774
NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Historic Test Year 2025	[3] Pro Forma Adjustment	[4] Balance
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	47	-	47
31	Rights of Way	365.2	868	-	868
32	Structures & Improvements	366	162	-	162
33	Mains	367	39,468	-	39,468
34	Measuring & Regulating Station Equipment	369	6,173	-	6,173
35	Communication Equipment	370	3,505	-	3,505
36	Other Equipment	371	351	-	351
37	TOTAL TRANSMISSION		50,575	-	50,575
DISTRIBUTION PLANT					
38	Land & Land Rights	374	11,638	-	11,638
39	Structures & Improvements	375	7,181	-	7,181
40	Mains	376	2,752,176	-	2,752,176
41	Measuring & Regulating Station Equipment	378	164,221	-	164,221
42	Measuring & Regulating Station Equipment	379	81,780	-	81,780
43	Services	380	1,684,481	-	1,684,481
44	Meters	381	192,839	-	192,839
45	Meter Installations	382	141,912	-	141,912
46	House Regulators	383	10,274	-	10,274
47	House Regulatory Installations	384	17,829	-	17,829
48	Industrial Measuring & Reg. Station Equipment	385	40,449	-	40,449
49	Other Property	386	1,274	-	1,274
50	Other Equipment	387	6,799	-	6,799
51	TOTAL DISTRIBUTION		5,112,854	-	5,112,854
GENERAL PLANT					
52	Land & Land Rights	389	13,523	-	13,523
53	Structures & Improvements	390	207,766	-	207,766
54	Office Furniture & Equipment	391	281,626	-	281,626
55	Transportation Equipment	392	66,908	-	66,908
56	Stores Equipment	393	16	-	16
57	Tools & Garage Equipment	394	44,808	-	44,808
58	Laboratory Equipment	395	438	-	438
59	Power Operated Equipment	396	13,798	-	13,798
60	Communication Equipment	397	3,095	-	3,095
61	Miscellaneous Equipment	398	1,510	-	1,510
62	Other Tangible Property	399	16	-	16
63	TOTAL GENERAL		633,504	-	633,504
64	Total Plant		$ 5,797,706	$ -	$ 5,797,706

Additions to Plant

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
INTANGIBLE PLANT			
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Additions to Plant

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	952
34	Measuring & Regulating Station Equipment	369	-
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		952
DISTRIBUTION PLANT			
38	Land & Land Rights	374	49
39	Structures & Improvements	375	847
40	Mains	376	215,764
41	Measuring & Regulating Station Equipment	378	7,879
42	Measuring & Regulating Station Equipment	379	17,128
43	Services	380	106,301
44	Meters	381	16,223
45	Meter Installations	382	6,707
46	House Regulators	383	95
47	House Regulatory Installations	384	220
48	Industrial Measuring & Reg. Station Equipment	385	630
49	Other Property	386	206
50	Other Equipment	387	76
51	TOTAL DISTRIBUTION		372,126
GENERAL PLANT			
52	Land & Land Rights	389	-
53	Structures & Improvements	390	8,126
54	Office Furniture & Equipment	391	11,317
55	Transportation Equipment	392	10,104
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	2,462
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	1,749
60	Communication Equipment	397	1,118
61	Miscellaneous Equipment	398	168
62	Other Tangible Property	399	-
63	TOTAL GENERAL		35,044
64	Total Plant		$ 408,122

Retirements

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Retirements

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	(17)
34	Measuring & Regulating Station Equipment	369	(0)
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		(17)
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	-
39	Structures & Improvements	375	(15)
40	Mains	376	(14,827)
41	Measuring & Regulating Station Equipment	378	(47)
42	Measuring & Regulating Station Equipment	379	-
43	Services	380	(23,042)
44	Meters	381	(1,323)
45	Meter Installations	382	(139)
46	House Regulators	383	(1)
47	House Regulatory Installations	384	(39)
48	Industrial Measuring & Reg. Station Equipment	385	3
49	Other Property	386	-
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		(39,431)
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	-
54	Office Furniture & Equipment	391	(2,008)
55	Transportation Equipment	392	-
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	(1,220)
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	(29)
61	Miscellaneous Equipment	398	(337)
62	Other Tangible Property	399	-
63	TOTAL GENERAL		(3,593)
64	Total Plant		$ (43,041)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] HTY 9-30-25
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	(0)
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	(0)
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		(0)
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	23
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		23

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] HTY 9-30-25
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	572
32	Structures & Improvements	366	157
33	Mains	367	23,116
34	Measuring & Regulating Station Equipment	369	4,255
35	Communication Equipment	370	2,463
36	Other Equipment	371	301
37	TOTAL TRANSMISSION		30,863
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,508
39	Structures & Improvements	375	3,577
40	Mains	376	563,000
41	Measuring & Regulating Station Equipment	378	41,529
42	Measuring & Regulating Station Equipment	379	13,438
43	Services	380	460,225
44	Meters	381	82,033
45	Meter Installations	382	47,685
46	House Regulators	383	3,921
47	House Regulatory Installations	384	9,463
48	Industrial Measuring & Reg. Station Equipment	385	19,979
49	Other Property	386	675
50	Other Equipment	387	4,707
51	TOTAL DISTRIBUTION		1,251,741
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	54,861
54	Office Furniture & Equipment	391	128,790
55	Transportation Equipment	392	29,187
56	Stores Equipment	393	7
57	Tools & Garage Equipment	394	16,560
58	Laboratory Equipment	395	178
59	Power Operated Equipment	396	5,174
60	Communication Equipment	397	826
61	Miscellaneous Equipment	398	1,055
62	Other Tangible Property	399	16
63	TOTAL GENERAL		236,655
64	Total Plant		$ 1,519,282

Summary of Accumulated Depreciation

Line #	Description	[1] Factor Or Reference	[2] Test Year Ended September 30, 2025 Amount	[3] Pro Forma Adjustment	[4] Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	-	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	(0)	-	(0)
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	23	-	23
4	Transmission Plant	Sch C-3, Pg 5	30,863	-	30,863
5	Distribution Plant	Sch C-3, Pg 5	1,251,741	-	1,251,741
6	General Plant	Sch C-3, Pg 5	236,655	-	236,655
7	Other Plant		-		-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,519,282	$ -	$ 1,519,282

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Historic Test Year 2025	[3] Pro Forma Adjustment	[4] Balance
INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	(0)	-	(0)
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	(0)	-	(0)
16	Other Equipment	337	-	-	-
17	TOTAL PRODUCTION & GATHERING		(0)	-	(0)
NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	23	-	23
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
29	TOTAL STORAGE & PROCESSING		23	-	23

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Historic Test Year 2025	[3] Pro Forma Adjustment	[4] Balance
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	572	-	572
32	Structures & Improvements	366	157	-	157
33	Mains	367	23,116	-	23,116
34	Measuring & Regulating Station Equipment	369	4,255	-	4,255
35	Communication Equipment	370	2,463	-	2,463
36	Other Equipment	371	301	-	301
37	TOTAL TRANSMISSION		30,863	-	30,863
DISTRIBUTION PLANT					
38	Land & Land Rights	374	1,508	-	1,508
39	Structures & Improvements	375	3,577	-	3,577
40	Mains	376	563,000	-	563,000
41	Measuring & Regulating Station Equipment	378	41,529	-	41,529
42	Measuring & Regulating Station Equipment	379	13,438	-	13,438
43	Services	380	460,225	-	460,225
44	Meters	381	82,033	-	82,033
45	Meter Installations	382	47,685	-	47,685
46	House Regulators	383	3,921	-	3,921
47	House Regulatory Installations	384	9,463	-	9,463
48	Industrial Measuring & Reg. Station Equipment	385	19,979	-	19,979
49	Other Property	386	675	-	675
50	Other Equipment	387	4,707	-	4,707
51	TOTAL DISTRIBUTION		1,251,741	-	1,251,741
GENERAL PLANT					
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	54,861	-	54,861
54	Office Furniture & Equipment	391	128,790	-	128,790
55	Transportation Equipment	392	29,187	-	29,187
56	Stores Equipment	393	7	-	7
57	Tools & Garage Equipment	394	16,560	-	16,560
58	Laboratory Equipment	395	178	-	178
59	Power Operated Equipment	396	5,174	-	5,174
60	Communication Equipment	397	826	-	826
61	Miscellaneous Equipment	398	1,055	-	1,055
62	Other Tangible Property	399	16	-	16
63	TOTAL GENERAL		236,655	-	236,655
64	Total Plant		$ 1,519,282	$ -	$ 1,519,282

Cost of Removal

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
INTANGIBLE PLANT			
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Cost of Removal

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	10
34	Measuring & Regulating Station Equipment	369	-
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		10
DISTRIBUTION PLANT			
38	Land & Land Rights	374	-
39	Structures & Improvements	375	12
40	Mains	376	3,511
41	Measuring & Regulating Station Equipment	378	313
42	Measuring & Regulating Station Equipment	379	196
43	Services	380	5,023
44	Meters	381	94
45	Meter Installations	382	95
46	House Regulators	383	1,029
47	House Regulatory Installations	384	3
48	Industrial Measuring & Reg. Station Equipment	385	87
49	Other Property	386	2
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		10,363
GENERAL PLANT			
52	Land & Land Rights	389	-
53	Structures & Improvements	390	105
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	-
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	-
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	10
61	Miscellaneous Equipment	398	87
62	Other Tangible Property	399	-
63	TOTAL GENERAL		201
64	Total Plant		$ 10,574

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
INTANGIBLE PLANT			
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	(23)
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		(23)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	4
34	Measuring & Regulating Station Equipment	369	2
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		5
DISTRIBUTION PLANT			
38	Land & Land Rights	374	-
39	Structures & Improvements	375	3
40	Mains	376	2,705
41	Measuring & Regulating Station Equipment	378	227
42	Measuring & Regulating Station Equipment	379	88
43	Services	380	4,744
44	Meters	381	34
45	Meter Installations	382	133
46	House Regulators	383	872
47	House Regulatory Installations	384	4
48	Industrial Measuring & Reg. Station Equipment	385	25
49	Other Property	386	0
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		8,835
GENERAL PLANT			
52	Land & Land Rights	389	-
53	Structures & Improvements	390	132
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	(872)
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	4
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	3
61	Miscellaneous Equipment	398	157
62	Other Tangible Property	399	-
63	TOTAL GENERAL		(576)
64	Total Plant		$ 8,241

Salvage

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
INTANGIBLE PLANT			
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

Salvage

Line #	Description	[1] Account Number	[2] Historic Test Year 2025
TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	-
34	Measuring & Regulating Station Equipment	369	-
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		-
DISTRIBUTION PLANT			
38	Land & Land Rights	374	-
39	Structures & Improvements	375	-
40	Mains	376	-
41	Measuring & Regulating Station Equipment	378	-
42	Measuring & Regulating Station Equipment	379	-
43	Services	380	-
44	Meters	381	-
45	Meter Installations	382	-
46	House Regulators	383	-
47	House Regulatory Installations	384	-
48	Industrial Measuring & Reg. Station Equipment	385	-
49	Other Property	386	-
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		-
GENERAL PLANT			
52	Land & Land Rights	389	-
53	Structures & Improvements	390	-
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	(749)
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	-
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	-
61	Miscellaneous Equipment	398	-
62	Other Tangible Property	399	-
63	TOTAL GENERAL		(749)
64	Total Plant		$ (749)

Working Capital

Line No	Description	[1] Historic Year 9/30/2025	[2] Reference
1	Working Capital for O & M Expense	$ 55,773	C-4, Page 2
2	Interest Payments	(7,572)	C-4, Page 7
3	Tax Payment Lag Calculations	4,013	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 66,613	

Summary of Working Capital

Line #	Description	[1] Reference	[2] Historic Test Year Expenses	[3] Factor	[4] Number of (Lead) / Lag Days [2] * [3]	[5] Totals
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				57.37
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 74,442	12.00	$ 893,303	
4	Purchased Gas Costs	Sch D-6	418,750	26.09	10,923,341	
5	Other Expenses	L 18 - L 3 to L 4	186,483	36.55	6,815,944	
6	Total	Sum (L 3 to L 5)	$ 679,675		$ 18,632,589	
7	O & M Expense Lag Days	L6, C 4 / C 2				27.41
8	Net (Lead) Lag Days	L 1 - L 7				29.95
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,862
10	Working Capital for O & M Expense	L 8 * L 9				$ 55,773
11	Interest Payments	Page 7				(7,572)
12	Tax Payment Lag Calculations	Page 8				4,013
13	Prepaid Expenses	Page 9				14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 66,613
15	Pro Forma O & M Expense		$ 698,521			
	Less:					
16	Uncollectible Expense		18,847			
17	Sub-Total		18,847			
18	Pro Forma Cash O&M Expense		$ 679,675			

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]	[5] Days Lag 365 / [4]
1	Annual Number of Days					365
2	September, 2024		$59,595			
3	October		$54,962	$49,570		
4	November		$65,027	$66,062		
5	December, 2024		$115,180	$130,278		
6	January, 2025		$180,732	$200,306		
7	February		$209,136	$183,549		
8	March		$200,671	$160,286		
9	April		$178,319	$106,926		
10	May		$148,644	$67,400		
11	June		$131,419	$49,633		
12	July		$110,237	$42,524		
13	August		$88,906	$37,847		
14	September, 2025		$72,798	$41,343		
15	Total	Sum L 2 to L 14	$1,615,626			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$124,279			
18	Total Sales for Year	Sum L 2 to L 14		$ 1,135,724		
19	Acct Rec Turnover Ratio	L 18 / L 17			9.14	
20	Collection Lag Day Factor	L 1 / L 19				39.93
21	Meter Read Lag Factor					2.23
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**57.37**

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Historic Test Year Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 32,610	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	41,832	12.00		
3	Weighted for Union	L1, C2 * C3			$ 391,322	
4	Weighted for Other	L2, C2 * C3			501,984	
5	Payroll Lag	L 3 + L 4	$ 74,442		$ 893,306	
6	Payroll Lag Days	L 5, C4 / C2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 505,975		$ 13,198,681	
8	Gas Cost Lag Days	L7, C4 / C2				26.09
OTHER O & M EXPENSES						
9	OCTOBER 2024	Page 5	$ 12,404		$ 323,056	
10	NOVEMBER 2024	Page 5	9,141		250,782	
11	DECEMBER 2024	Page 5	10,855		287,049	
12	JANUARY 2025	Page 5	25,282		1,499,042	
13	FEBRUARY 2025	Page 5	15,794		514,617	
14	MARCH 2025	Page 5	9,353		273,241	
15	APRIL 2025	Page 5	12,385		289,995	
16	MAY 2025	Page 5	13,770		597,078	
17	JUNE 2025	Page 5	14,096		499,028	
18	JULY 2025	Page 5	20,034		1,249,027	
19	AUGUST 2025	Page 5	13,203		391,825	
20	SEPTEMBER 2025	Page 5	38,365		941,232	
21	TOTAL		$ 194,681		$ 7,115,972	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				36.55

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2024					
1	Total Disbursements for Month	32,838	$ 62,746		
2	Total Disbursements for Expenses	3,838	$ 12,404	$ 323,056	26.04
NOVEMBER 2024					
3	Total Disbursements for Month	23,901	$ 38,794		
4	Total Disbursements for Expenses	3,565	$ 9,141	$ 250,782	27.43
DECEMBER 2024					
5	Total Disbursements for Month	24,687	$ 38,022		
6	Total Disbursements for Expenses	4,006	$ 10,855	$ 287,049	26.44
JANUARY 2025					
7	Total Disbursements for Month	21,368	$ 50,983		
8	Total Disbursements for Expenses	3,947	$ 25,282	$ 1,499,042	59.29
FEBRUARY 2025					
9	Total Disbursements for Month	18,066	$ 32,989		
10	Total Disbursements for Expenses	3,439	$ 15,794	$ 514,617	32.58
MARCH 2025					
11	Total Disbursements for Month	18,513	$ 27,337		
12	Total Disbursements for Expenses	3,735	$ 9,353	$ 273,241	29.21
APRIL 2025					
13	Total Disbursements for Month	25,630	$ 41,058		
14	Total Disbursements for Expenses	4,257	$ 12,385	$ 289,995	23.41
MAY 2025					
15	Total Disbursements for Month	34,781	$ 47,440		
16	Total Disbursements for Expenses	4,049	$ 13,770	$ 597,078	43.36
JUNE 2025					
17	Total Disbursements for Month	29,782	$ 46,699		
18	Total Disbursements for Expenses	4,127	$ 14,096	$ 499,028	35.40
JULY 2025					
19	Total Disbursements for Month	31,463	$ 57,790		
20	Total Disbursements for Expenses	4,523	$ 20,034	$ 1,249,027	62.35
AUGUST 2025					
21	Total Disbursements for Month	32,254	$ 46,003		
22	Total Disbursements for Expenses	4,224	$ 13,203	$ 391,825	29.68
SEPTEMBER 2025					
23	Total Disbursements for Month	34,037	$ 80,893		
24	Total Disbursements for Expenses	3,958	$ 38,365	$ 941,232	24.53
25	Total Test Month Expense Disbursement	47,668	$ 194,681	$ 7,115,972	36.55

Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	OCTOBER 2024	37	$ 38,708	$ 521,883	13.48
2	NOVEMBER 2024	38	42,900	573,631	13.37
3	DECEMBER 2024	42	61,187	1,434,065	23.44
4	JANUARY 2025	45	101,888	1,975,569	19.39
5	FEBRUARY 2025	42	73,452	1,791,212	24.39
6	MARCH 2025	33	37,168	1,424,885	38.34
7	APRIL 2025	35	39,413	1,421,523	36.07
8	MAY 2025	31	26,967	1,017,164	37.72
9	JUNE 2025	32	22,772	833,747	36.61
10	JULY 2025	28	22,723	835,609	36.77
11	AUGUST 2025	27	20,780	750,436	36.11
12	SEPTEMBER 2025	30	18,017	618,957	34.35
13	Total		$ 505,975	$ 13,198,681	
14	Purchase Gas Lag Days				26.09

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2025	Sch C-1			$ 3,692,780
2	Long-term Debt Ratio	Sch B-6			47.10%
3	Embedded Cost of Long-term Debt	Sch B-6			4.69%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 81,573
5	Daily Amount	L 4 / L 5 [2]	365		$ 223
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		57.37	
8	Interest Payment lag days	L 7 - L 6			(33.9)
9	Total Interest for Working Capital	L 5 * L 8			$ (7,572)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount 365
1	**FEDERAL INCOME TAX**				$ 48,229						
2	First Payment	01/05/25	04/01/25	86.00	$ 12,057	1,036,919					
3	Second Payment	03/15/25	04/01/25	17.00	12,057	204,972					
4	Third Payment	06/15/25	04/01/25	(75.00)	12,057	(904,290)					
5	Fourth Payment	09/15/25	04/01/25	(167.00)	12,057	(2,013,553)					
6	Total				$ 48,229	$ (1,675,951)	(34.75)	(57.37)	22.62	$ 1,090,791	$ 2,988
7	**STATE INCOME TAX**				$ 13,240						
8	First Payment	12/15/24	04/01/25	107.00	$ 3,310	354,166					
9	Second Payment	03/15/25	04/01/25	17.00	3,310	56,269					
10	Third Payment	06/15/25	04/01/25	(75.00)	3,310	(248,248)					
11	Fourth Payment	09/15/25	04/01/25	(167.00)	3,310	(552,765)					
12	Total				$ 13,240	(390,576)	(29.50)	(57.37)	27.87	$ 368,955	$ 1,011
13	**PA PROPERTY TAX**				$ 890						
14	First Payment	03/31/25	04/01/25	1.00	$ 445	445					
15	Second Payment	09/30/25	04/01/25	(182.00)	445	(80,990)					
16	Total				$ 890	(80,545)	(90.50)	(57.37)	(33.13)	$ (29,488)	$ (81)
17	**PURTA**				$ 1,254						
18	Payment	05/01/25	04/01/25	(30.00)	$ 1,254	(37,620)	(30.00)	(57.37)	27.37	$ 34,318	$ 94
19	Total Working Capital For Other Taxes										$ 4,013

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Miscellaneous	[6] Subscriptions	[7] Postage	[8] Rent	[9] Maintenance & Services
1	September, 2024		17,897	7,651	3,412	385	108	2	-	6,338
2	October		18,551	6,660	3,033	400	280	3	-	8,174
3	November		17,249	6,247	2,654	400	199	3	-	7,746
4	December, 2024		17,645	5,421	2,275	326	118	0	-	9,504
5	January, 2025		16,934	4,526	1,896	571	372	0	-	9,569
6	February		14,804	3,722	1,517	469	545	0	-	8,551
7	March		13,077	2,826	1,137	429	575	2	-	8,108
8	April		10,792	1,968	758	417	648	(3)	-	7,004
9	May		8,657	1,070	379	350	539	4	-	6,315
10	June		7,338	172	-	283	433	5	-	6,445
11	July		9,081	299	-	224	561	2	-	7,996
12	August		16,621	8,732	-	233	399	4	-	7,253
13	September, 2025		18,558	7,869	3,413	180	290	2	-	6,804
14	TOTAL		$ 187,204	$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
17	Monthly Average	13		$ 4,397	$ 1,575	$ 359	$ 390	$ 2	$ -	$ 7,677
18	Rate Case Amount		$ 14,400							

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-5
Witness: A. M. Keller
Page 1 of 1

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2024	$27,677
2	October	32,669
3	November	32,041
4	December, 2024	25,192
5	January, 2025	15,334
6	February	8,991
7	March	3,692
8	April	11,088
9	May	17,289
10	June	24,134
11	July	30,732
12	August	36,859
13	September, 2025	41,904
14	Total	$ 307,601
15	Number of Months	13
16	Average Monthly Balance	$ 23,662

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-6
Witness: D. T. Espigh

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (676,795)	
2	Sub-total		(676,795)
3	ADIT on CIAC	39,863	39,863
4	ADIT for Repairs Tax Deduction		
5	Federal ADIT		(636,932)
6	State Repair Regulatory Liability	(43,690)	(43,690)
7	CIAC Tax Gross-Up Regulatory Liability	(744)	(744)
8	Pro-Rata Adjustment		-
9	Balance At September 30, 2025		$ (681,366)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-7
Witness: A. M. Keller
Page 1 of 1

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2024	$ 20,721
2	October	$ 21,053
3	November	$ 21,369
4	December, 2024	$ 21,641
5	January, 2025	$ 22,111
6	February	$ 22,868
7	March	$ 24,005
8	April	$ 24,716
9	May	$ 24,801
10	June	$ 24,688
11	July	$ 24,591
12	August	$ 24,522
13	September, 2025	$ 24,475
14	Total	$ 301,560
15	Number of Months	13
16	Average Monthly Balance	$ 23,197

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule C-8
Witness: A. M. Keller

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2024	$ 30,420
2	October	30,020
3	November	29,626
4	December, 2024	29,997
5	January, 2025	29,829
6	February	30,374
7	March	29,642
8	April	29,028
9	May	28,754
10	June	27,778
11	July	26,665
12	August	25,527
13	September, 2025	24,707
14	Total	$ 372,366
15	Number of Months	13
16	Average Monthly Balance	$ 28,644

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Pro Forma Test Year Rate Increase	[3] Pro Forma Test Year At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 693,752	$ -	$ 693,752
2	Gas Supply & Cost Adjustment Revenue		469,879	-	469,879
3	Other Revenues		12,240	-	12,240
4	Revenue Increase			35,831	35,831
5	Total operating revenues		1,175,870	35,831	1,211,701
	OPERATING EXPENSES				
6	Manufactured Gas		-	-	-
7	Gas Supply Production		418,750	-	418,750
8	Transmission		-		
9	Distribution		92,189	-	92,189
10	Customer Accounts		54,284	-	54,284
11	Uncollectible Expense	1.723%	18,847	617	19,464
12	Customer Information & Services		13,904	-	13,904
13	Sales		1,386	-	1,386
14	Administrative & General		99,161	-	99,161
15	Depreciation & Amortization		146,739	-	146,739
16	Taxes other than income taxes		12,624	-	12,624
17	Total operating expenses		857,885	617	858,502
18	Net operating income Before Income Tax		317,986	35,214	353,199
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		51,712		51,712
20	Pro Forma Income Tax on Revenue Increase			9,757	9,757
21	Net Income (loss)		$ 266,273	$ 25,457	$ 291,730

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab

Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates Actual For Year End 09/30/25	[3] Test Year At Present Rates Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates Pro Forma Adjusted For Test Year 9/30/25	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 693,337	$ 39,915	$ 733,252		$ 733,252
2	Comm & Ind (N/NT)	481	257,448	(10,496)	246,951		246,951
3	Comm & Ind (DS)	489	50,460	(90)	50,370		50,370
4	Lg Transport/Other	489	107,266	(1,751)	105,515		105,515
5	Interruptible	489	28,746	(1,204)	27,541		27,541
6	Forfeited Discounts	487	5,460	-	5,460		5,460
7	Miscellaneous Service Revenues	488, 495	4,674	-	4,674		4,674
8	Rent from Gas Properties	493	2,106	-	2,106		2,106
9	Rate Increase			-	-	35,831	35,831
10	Total operating revenues		1,149,495	26,375	1,175,870	35,831	1,211,701
	OPERATING EXPENSES						
11	Gas Production		-	-	-		-
12	Gas Supply Production		375,853	42,897	418,750		418,750
13	Transmission		-		-		
14	Distribution		91,676	513	92,189		92,189
15	Customer Accounts		54,100	184	54,284		54,284
16	Uncollectible Expense	1.723%	16,582	2,264	18,847	617	19,464
17	Customer Information & Services		13,890	15	13,904		13,904
18	Sales		1,378	8	1,386		1,386
19	Administrative & General		99,029	132	99,161		99,161
20	Depreciation & Amortization		142,830	3,909	146,739		146,739
21	Taxes other than income taxes		12,556	68	12,624		12,624
22	Total operating expenses		807,895	49,990	857,885	617	858,502
23	Net Operating Income - BIT		$ 341,601	$ (23,615)	$ 317,986	$ 35,214	$ 353,199

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab

Summary of Pro Forma Adjustments

Line #	Description		[1] As Actual And Allocated	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
					Adjustments										
					Revenues	Gas Costs	Salaries & Wages				Uncollectibles Expense			Sub-Total Adjustments	Total Proforma
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 406,526		$ (8,697)									$ (8,697)	$ 397,829
2	Comm & Ind (N/NT)	481	156,913		(12,891)									(12,891)	144,022
3	Comm & Ind (DS)	489	34,382		(7)									(7)	34,375
4	Lg Transport/Other	489	95,826		(1,876)									(1,876)	93,950
5	Interruptible	489	24,780		(1,204)									(1,204)	23,576
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	286,810		48,613									48,613	335,423
7	Comm & Ind (N/NT)	481	100,534		2,395									2,395	102,929
8	Comm & Ind (DS)	489	16,078		(82)									(82)	15,996
9	Lg Transport/Other	489	11,440		125									125	11,565
10	Interruptible Transport	489	3,966		-									-	3,966
11	Forfeited Discounts	487	5,460		-									-	5,460
12	Miscellaneous Service Revenues	488, 495	4,674		-									-	4,674
13	Rent from Gas Properties	493	2,106		-									-	2,106
14	Rate Increase		-											-	-
15	Total operating revenues		1,149,495		26,375	-	-	-	-	-	-	-	-	26,375	1,175,870
	OPERATING EXPENSES														-
16	Gas Production		-											-	-
17	Gas Supply Production		375,853			42,897								42,897	418,750
18	Transmission		-												-
19	Distribution		91,676				513							513	92,189
20	Customer Accounts		54,100				184							184	54,284
21	Uncollectible Expense		16,582								2,264			2,264	18,847
22	Customer Information & Services		13,890				15							15	13,904
23	Sales		1,378				8							8	1,386
24	Administrative & General		99,029				132							132	99,161
25	Depreciation & Amortization		142,830											-	142,830
26	Taxes other than income taxes		12,556											-	12,556
														-	-
27	Total operating expenses		$ 807,895	$ -	$ -	$ 42,897	$ 851	$ -	$ -	$ -	$ 2,264	$ -	$ -	$ 46,012	$ 853,907
28	Net operating income Before Income Tax		$ 341,601	$ -	$ 26,375	$ (42,897)	$ (851)	$ -	$ -	$ -	$ (2,264)	$ -	$ -	$ (19,638)	$ 321,963

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab
Page 2 of 2

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
				Adjustments										
												Taxes Other Than		
	OPERATING REVENUES			D-14	D-15	D-16	D-17	D-18	D-19		Depreciation D-21	Income D-31		TOTAL Adjusted
	Customer & Distribution Revenue													
29	Residential (R/RT)	$ 397,829												$ 397,829
30	Comm & Ind (N/NT)	144,022												144,022
31	Comm & Ind (DS)	34,375												34,375
32	Lg Transport/Other	93,950												93,950
33	Interruptible	23,576												23,576
	Revenue for Cost of Gas													-
34	Residential (R/RT)	335,423												335,423
35	Comm & Ind (N/NT)	102,929												102,929
36	Comm & Ind (DS)	15,996												15,996
37	Lg Transport/Other	11,565												11,565
38	Interruptible Transport	3,966												3,966
39	Forfeited Discounts	5,460												5,460
40	Miscellaneous Service Revenues	4,674												4,674
41	Rent from Gas Properties	2,106												2,106
42	Rate Increase	-												-
43	Total operating revenues	1,175,870	-	-	-	-	-	-	-	-	-	-	-	1,175,870
	OPERATING EXPENSES													
44	Gas Production	-												-
45	Gas Supply Production	418,750												418,750
46	Transmission	-												-
47	Distribution	92,189												92,189
48	Customer Accounts	54,284												54,284
49	Uncollectible Expense	18,847												18,847
50	Customer Information & Services	13,904												13,904
51	Sales	1,386												1,386
52	Administrative & General	99,161												99,161
53	Depreciation & Amortization	142,830									3,909			146,739
54	Taxes other than income taxes	12,556										68		12,624
55	Total operating expenses	$ 853,907	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,909	$ 68	$ -	$ 857,885
56	Net operating income Before Income Tax	$ 321,963	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,909)	$ (68)	$ -	$ 317,986

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-5
Witness: S. A. Epler
Page 1 of 1

Adjustment - Revenue Adjustments

Line #	Description	Reference Or Account Number	[1] 2025 Actual	[2] PRO FORMA ADJUSTMENTS Other Adjustments	[3] Rev/PGC Adj Annualization	[4] Total Proforma Adjustments	[5] Proforma Adjusted At Present Rates
						D-5A	
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 406,526	$ (8,697)		$ (8,697)	$ 397,829
2	Comm & Ind (N/NT)	481	156,913	(12,891)		(12,891)	144,022
3	Comm & Ind (DS)	489	34,382	(7)		(7)	34,375
4	Lg Transport/Other	489	95,826	(1,876)		(1,876)	93,950
5	Interruptible	489	24,780	(1,204)		(1,204)	23,576
6	Cust Chg & Distrib Revenue		718,427	(24,675)	-	(24,675)	693,752
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	286,810	8,065	40,548	48,613	335,423
8	Comm & Ind (N/NT)	481	100,534	46	2,349	2,395	102,929
9	Comm & Ind (DS)	489	16,078	(82)		(82)	15,996
10	Lg Transport/Other	489	11,440	125		125	11,565
11	Interruptible Transport	489	3,966	-		-	3,966
12	Revenue for Cost of Gas		418,829	8,153	42,897	51,050	469,879
							-
13	Total Customer Revenue		1,137,255	(16,522)	42,897	26,375	1,163,630
14	Forfeited Discounts	487	5,460		-	-	5,460
15	Miscellaneous Service Revenues	488	3,694		-	-	3,694
							-
16	Rent from Gas Properties	493	2,106		-	-	2,106
17	Other Revenues	495	980			-	980
18	TOTAL REVENUES		$ 1,149,495	$ (16,522)	$ 42,897	$ 26,375	$ 1,175,870

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-5A
Witness: S. A. Epler

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] 2025 Actual	[3] Revised Actual	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 693,337	$ 733,252	$ 39,915	
2	Comm & Ind (N/NT)		257,448	246,951	(10,496)	
3	Comm & Ind (DS)		50,460	50,370	(90)	
4	Lg Transport/Other		107,266	105,515	(1,751)	
5	Interruptible		28,746	27,541	(1,204)	
6	Total		$ 1,137,255	$ 1,163,630	$ 26,375	$ 26,375
COST OF COMMODITY						
7	Residential (R/RT)		$ 286,810	$ 335,423	$ 48,613	
8	Comm & Ind (N/NT)		100,534	102,929	2,395	
9	Comm & Ind (DS)		16,078	15,996	(82)	
10	Lg Transport/Other		11,440	11,565	125	
11	Interruptible		3,966	3,966	0	
12	Total		$ 418,829	$ 469,879	$ 51,050	$ 51,050
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 406,526	$ 397,829	$ (8,697)	
14	Comm & Ind (N/NT)		156,913	144,022	(12,891)	
15	Comm & Ind (DS)		34,382	34,375	(7)	
16	Lg Transport/Other		95,826	93,950	(1,876)	
17	Interruptible		24,780	23,576	(1,204)	
18	Total		$ 718,427	$ 693,752	$ (24,675)	$ (24,675)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-6
Witness: S. A. Epler
Page 1 of 1

Adjustment - Gas Costs

Line #	Description	[1] Actual Gas Costs	[2] PRO FORMA ADJUSTMENTS D-5A Gas Costs	[3]	[4] Gas Cost Pro Forma Adjustments	[5] Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 375,853			$ -	$ 375,853
2	Residential (R/RT)		40,548		40,548	40,548
3	Comm & Ind (N/NT)		2,349		2,349	2,349
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 375,853	$ 42,897	$ -	$ 42,897	$ 418,750

Adjustment - Salaries & Wages

Line #	Description	[1] Recorded Year 09/30/25	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	28,974	-	28,974	335	29,309
5	Customer Account Operations Expenses	15,927	-	15,927	184	16,111
6	Total Cust. Service & Inform. Operations Exp	1,259	-	1,259	15	1,274
7	Total Operation Sales Expenses	684	-	684	8	691
8	Total A & G Operation Expenses	10,185	-	10,185	118	10,303
9	Total Operations	57,028	-	57,028	660	57,688
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	15,339	-	15,339	177	15,517
14	Total A&G Maintenance	1,223	-	1,223	14	1,237
15	Total Maintenance	16,563	-	16,563	191	16,754
16	Total Payroll to Expense	$ 73,591	$ -	$ 73,591	$ 851	$ 74,442
17	Percent Increase					1.156%

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union At 6-1	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Actual Payroll For TY 9-30-25		$ 31,759	$ 16,754	$ 25,078	$ 73,591
	Annualize for Wage Increase to 9-30-24					
2	Percent Increase		4.00%			
3	Union Increase At 6/1 Annualization Factor	6/1/24	67%			
4	Increase for wage rate changes	L 1 * L 2 * L 3	851	0	0	$ 851
5	Annualized Salaries & Wages at 9-30-25 Rates	L 1 + L 4	$ 32,610	$ 16,754	$ 25,078	
6	Annualization of D-9 changes FY2025					
7	Pro Forma Salaries & Wages for TY		$ 32,610	$ 16,754	$ 25,078	
8	Pro Forma Adjustment to S&W					$ 851
9	Annualization Factor	L 8 / L 1				1.157%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-11
Witness: V. K. Ressler
Page 1 of 1

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
1	2023		$ 23,142	$ 1,210,517	1.91%	
2	2024		$ 17,089	$ 1,020,566	1.67%	
3	2025		$ 17,879	$ 1,140,677	1.57%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 19,370	$ 1,123,920		1.723%
5	2025 Recorded				$ 17,879	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.723%		$ 1,169,090		
7	Pro Forma at Present Rate Revenue	[1] * [3]			20,143	
8	Total for Test Year					$ 2,264

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-21
Witness: J.F. Weidmayer

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Actual 9/30/25 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	2	(2)	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	0	(0)	-
11	Producing Gas Wells-Well Construction	330	(0)	0	-
12	Producing Gas Wells-Well Equipment	331	(0)	0	-
13	Field Lines	332	17	(17)	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	0	(0)	-
16	Other Equipment	337	-	-	-
17	TOTAL PRODUCTION & GATHERING		20	(20)	-
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	(23)	23	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	226	(226)	-
28	Other Equipment	357	0	(0)	-
					-
29	TOTAL STORAGE & PROCESSING		203	(203)	-

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Actual 9/30/25 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	11	(0)	11
32	Structures & Improvements	366	0	(0)	0
33	Mains	367	399	8	408
34	Measuring & Regulating Station Equipment	369	95	(4)	91
35	Communication Equipment	370	98	(12)	86
36	Other Equipment	371	6	(0)	6
37	TOTAL TRANSMISSION		610	(8)	602
DISTRIBUTION PLANT					
38	Land & Land Rights	374	43	0	43
39	Structures & Improvements	375	120	9	129
40	Mains	376	43,957	326	44,283
41	Measuring & Regulating Station Equipment	378	4,527	(169)	4,358
42	Measuring & Regulating Station Equipment	379	2,211	294	2,506
43	Services	380	47,862	(3,382)	44,480
44	Meters	381	5,534	1,598	7,132
45	Meter Installations	382	3,442	(25)	3,418
46	House Regulators	383	827	(486)	341
47	House Regulatory Installations	384	466	(132)	334
48	Industrial Measuring & Reg. Station Equipment	385	840	(41)	799
49	Other Property	386	39	(10)	29
50	Other Equipment	387	94	1	94
51	TOTAL DISTRIBUTION		109,960	(2,015)	107,945
GENERAL PLANT					
52	Land & Land Rights	389	2	(2)	-
53	Structures & Improvements	390	6,467	956	7,423
54	Office Furniture & Equipment	391	22,875	(452)	22,422
55	Transportation Equipment	392	4,951	1,199	6,150
56	Stores Equipment	393	1	0	1
57	Tools & Garage Equipment	394	2,223	81	2,304
58	Laboratory Equipment	395	22	0	22
59	Power Operated Equipment	396	861	64	925
60	Communication Equipment	397	206	182	388
61	Miscellaneous Equipment	398	395	(312)	83
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		38,002	1,717	39,719
64	TOTAL DEPRECIATION		$ 148,795	$ (530)	$ 148,266
65	CHARGED TO CLEARING ACCOUNTS		$ (8,241)	$ (1,526)	$ (9,767)
66	NET SALVAGE AMORTIZATION		$ 7,730	$ 510	$ 8,241

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-31
Witness: T. A. Hazenstab
Page 1 of 1

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Actual Amounts 9/30/25	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/25
1	PURTA Taxes	408.1		$ 1,254	$ -	$ 1,254
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		890	-	890
4	Social Security	408.1	D-32	5,435	63	5,498
5	FUTA	408.1	D-32	70	1	71
6	SUTA	408.1	D-32	355	4	359
7	PUC Assessment	408.1		4,552	-	4,552
8	Total			$ 12,556	$ 68	$ 12,624

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-32
Witness: T. A. Hazenstab
Page 1 of 1

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Actual 9/30/25 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 73,591	$ 851	
2	FICA Expense		5,435		
3	FICA Expense - Percent	L 2 / L 1	7.39%	7.39%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 63
5	FUTA Expense		70		
6	FUTA Expense - Percent	L 5 / L 1	0.10%	0.10%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			1
8	SUTA Expense		355		
9	SUTA Expense - Percent	L 8 / L 1	0.48%	0.48%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			4
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 68

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-33
Witness: D. T. Espigh
Page 1 of 1

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,175,870	$ 35,831	$ 1,211,701
2	Operating Expenses			(857,885)	(617)	(858,502)
3	OIBIT	L 1 + L 2		317,986	35,214	353,199
	Interest Expense					
4	Rate Base	Sch A-1	3,692,780			
5	Weighted Cost of Debt	Sch B-7	0.02210			
6	Synchronized Interest Expense	L 4 * L 5		(81,610)	-	(81,610)
7	Base Taxable Income	L 3 + L 6		236,376	35,214	271,589
8	Total Tax Depreciation	Sch D-34	$ 305,639			
9	Pro Forma Book Depreciation	Sch D-34	152,707			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(152,932)		(152,932)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 83,443	$ 35,214	$ 118,657
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	8.49%	$ (7,084)	$ (2,990)	$ (10,074)
14	Total Tax Depreciation	Sch D-34	$ 273,557			
15	Pro Forma Book Depreciation	Sch D-34	152,707			
16	Federal Tax Deducts (Over) Under Book	L 15 - L 14		(120,850)	-	(120,850)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		108,441	32,224	140,665
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(22,773)	(6,767)	(29,540)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(29,857)	(9,757)	(39,614)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 148,266			
22	Total Tax Depreciation	Sch D-34	263,721			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		115,455	-	115,455
24	Deferred Federal Taxable Income	L 23		$ 115,455	$ -	$ 115,455
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(19,374)	-	(19,374)
	Deferred State Income Taxes					
26	Repairs			(3,323)		(3,323)
27	CIAC			158		158
28	State Deferred Income Tax (Expense)/Refund			(3,166)	-	(3,166)
29	Net Income Tax Expense	L20 + L 25 + L28		(52,397)	(9,757)	(62,153)
	Other Tax Adjustments					
30	ITC			684		684
31	Combined Income Tax Expense	L 29 + L 30		$ (51,712)	$ (9,757)	$ (61,469)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (41,462)	$ (6,767)	$ (48,229)
33	State Income Tax Expense	L 13 + L 28		(10,250)	(2,990)	(13,240)
34	Total Income Tax Expense	L 32 + L 33		$ (51,712)	$ (9,757)	$ (61,469)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2025
($ in Thousands)

Schedule D-34
Witness: D. T. Espigh
Page 1 of 1

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 188,869	
2	Cost of Removal		9,836	
3	Repairs Tax Deduction		91,962	
4	Other Tax Basis Adjustments		(17,110)	
5	Total Federal Accelerated Tax Depreciation			$ 273,557
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		32,083	
7	Total State Accelerated Tax Depreciation			$305,639
	Straight Line Tax Depreciation			
8	Gas Plant		$ 148,266	
9	Total Tax Depreciation			$ 148,266
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 148,266	
11	Net Salvage Amortization		8,241	
12	Depreciation Charged to Clearing Accounts	(9,767)		
13	Estimated Percent of Clearing Charged to CWIP	39%		
14	Depreciation Charged to CWIP		(3,799)	
15	Book Depreciation for Tax Calculation			$ 152,707

UGI Utilities, Inc. - Gas Division | **Schedule D-35**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Historic Period - 12 Months Ended September 30, 2025 | **Page 1 of 1**
($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.017230)
3	NET REVENUES	Sum L 1 to L 2		0.982770
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	8.4900%	(0.083437)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.899333
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.188860)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.710473
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.407513
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		27.230%
INCOME TAX FACTOR				
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	8.4900%	(0.084900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.915100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.192171)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.722929
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.383262
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		27.707%

UGI GAS

EXHIBIT B

RATE OF RETURN

UGI GAS EXHIBIT B

UGI UTILITIES, INC. – GAS DIVISION

Exhibit to Accompany the

Direct Testimony

of

Dylan W. D'Ascendis

ScottMadden, Inc.

Concerning

Fair Rate of Return

UGI Utilities, Inc.
Table of Contents
UGI Gas Exhibit B - Schedules to the Direct Testimony of Dylan W. D'Ascendis

	Direct Schedule
Summary of Overall Rate of Return and Cost of Common Equity	DWD-1
Financial Profile and Capital Structures of the Proxy Group of Seven Natural Gas Companies	DWD-2
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Indicated Common Equity Cost Rate Using the Risk Premium Model	DWD-4
Market Indices Correlation	DWD-5
Indicated Common Equity Cost Rate Using the Capital Asset Pricing Model	DWD-6
Basis of Selection for the Non-Price Regulated Companies Comparable in Total Risk to the Utility Proxy Group	DWD-7
Cost of Common Equity Models Applied to the Non-Price Regulated Proxy Group	DWD-8
Market Capitalization for the Company And the Proxy Group of Seven Natural Gas Companies	DWD-9
Calculation of R-Squareds of Betas for the Proxy Group of Seven Natural Gas Companies	DWD-10
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity	DWD-11

UGI Utilities, Inc.
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	45.75%	5.17%	(1)	2.37%
Common Equity	54.25%	10.75%	(2)	5.83%
Total	100.00%			8.20%

Notes:
(1) Company-provided
(2) From page 2 of this Schedule.

UGI Utilities, Inc.
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seven Natural Gas Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.53%
2.	Risk Premium Model (RPM) (2)	10.41% - 10.80%
3.	Capital Asset Pricing Model (CAPM) (3)	10.17% - 11.30%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	10.96% - 11.35%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.17% - 11.35%
6.	Business Risk Adjustment (5)	0.05%
7.	Flotation Cost Adjustment (6)	0.12%
8.	Indicated Common Equity Cost Rate after Adjustment	10.34% - 11.52%
9.	Recommended Common Equity Cost Rate	10.75%

Notes:
(1) From page 1 of Schedule DWD-3.
(2) From page 1 of Schedule DWD-4.
(3) From page 1 and 2 of Schedule DWD-6.
(4) From page 1 of Schedule DWD-8.
(5) Business risk adjustment to reflect UGI Utilities, Inc.'s unique risk compared to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.
(6) From page 1 of Schedule DWD-11.

Proxy Group of Seven Natural Gas Companies
Capitalization and Financial Statistics (1)
2020 - 2024, Inclusive

	2024	2023	2022	2021	2020	
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$9,449.074	$8,552.511	$7,829.013	$6,826.718	$6,113.626	
Short-Term Debt	$408.230	$647.038	$703.711	$564.491	$233.392	
Total Capital Employed	$9,857.304	$9,199.549	$8,532.724	$7,391.209	$6,347.018	
Indicated Average Capital Cost Rates (2)						
Total Debt	4.41 %	3.98 %	3.14 %	2.84 %	3.32 %	
Preferred Stock	3.37 %	4.31 %	3.56 %	4.54 %	6.26 %	
Capital Structure Ratios						5 YEAR AVERAGE
Based on Total Permanent Capital:						
Long-Term Debt	51.07 %	51.54 %	50.93 %	50.05 %	49.19 %	50.55 %
Preferred Stock	-	0.36	1.29	1.36	0.84	0.77
Common Equity	48.93	48.10	47.78	48.59	49.97	48.68
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	54.13 %	54.05 %	55.68 %	55.18 %	52.51 %	54.31 %
Preferred Stock	-	0.31	1.17	1.32	0.81	0.72
Common Equity	45.87	45.64	43.15	43.50	46.68	44.97
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	5.16 %	5.19 %	3.96 %	4.75 %	4.22 %	4.66 %
Market / Average Book Ratio	165.45	169.94	199.96	191.16	197.63	184.83
Dividend Yield	3.45	3.44	2.99	3.14	2.91	3.19
Dividend Payout Ratio	66.77	66.89	53.99	59.48	55.94	60.61
Rate of Return on Average Book Common Equity	8.63 %	8.82 %	8.54 %	9.55 %	8.27 %	8.76 %
Total Debt / EBITDA (3)	4.89 x	5.05 x	5.13 x	5.38 x	5.18 x	5.13 x
Funds from Operations / Total Debt (4)	16.15 %	28.38 %	14.78 %	9.77 %	15.23 %	16.86 %
Total Debt / Total Capital	54.13 %	54.05 %	55.68 %	55.18 %	52.51 %	54.31 %

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K.

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Seven Natural Gas Companies
2020 - 2024, Inclusive

	2024	2023	2022	2021	2020	5 YEAR AVERAGE
Atmos Energy Corporation						
Long-Term Debt	39.04 %	37.62 %	45.81 %	39.35 %	40.02 %	40.37 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	60.96	62.38	54.19	60.65	59.98	59.63
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Chesapeake Utilities Corporation						
Long-Term Debt	48.08 %	49.17 %	41.87 %	42.31 %	42.82 %	44.85 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	51.92	50.83	58.13	57.69	57.18	55.15
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources Corporation						
Long-Term Debt	58.24 %	59.16 %	58.49 %	57.81 %	55.35 %	57.81 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	41.76	40.84	41.51	42.19	44.65	42.19
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NiSource Inc.						
Long-Term Debt	60.60 %	57.26 %	55.77 %	57.09 %	61.64 %	58.47 %
Preferred Stock	0.00	2.51	9.03	9.55	5.87	5.39
Common Equity	39.40	40.23	35.20	33.36	32.49	36.14
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Holding Company						
Long-Term Debt	55.25 %	55.11 %	53.21 %	52.12 %	51.81 %	53.50 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	44.75	44.89	46.79	47.88	48.19	46.50
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt	40.71 %	44.05 %	42.10 %	41.74 %	41.76 %	42.07 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	59.29	55.95	57.90	58.26	58.24	57.93
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Southwest Gas Holdings, Inc.						
Long-Term Debt	55.54 %	58.43 %	59.25 %	59.90 %	50.90 %	56.80 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	44.46	41.57	40.75	40.10	49.10	43.20
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Seven Natural Gas Companies						
Long-Term Debt	51.07 %	51.54 %	50.93 %	50.05 %	49.19 %	50.55 %
Preferred Stock	0.00	0.36	1.29	1.36	0.84	0.77
Common Equity	48.93	48.10	47.78	48.59	49.97	48.68
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

UGI Utilities, Inc.
Operating Subsidiary Company Capital Structures of the
Proxy Group of Seven Natural Gas Companies

Company Name	Parent Company Ticker	2024 Common Equity	2024 Long-Term Debt	2024 Total Capital
Atmos Energy Corporation	ATO	59.93%	40.07%	100.00%
Chesapeake Utilities Corporation	CPK	51.71%	48.29%	100.00%
New Jersey Natural Gas Company	NJR	54.18%	45.82%	100.00%
Northern Indiana Public Service Company	NI	58.24%	41.76%	100.00%
Northwest Natural Gas Company	NWN	47.86%	52.14%	100.00%
ONE Gas, Inc.	OGS	56.09%	43.91%	100.00%
Southwest Gas Corporation	SWX	48.28%	51.72%	100.00%
	Average	53.75%	46.25%	
	Maximum	59.93%	52.14%	
	Minimum	47.86%	40.07%	

Source: S&P Global Market Intelligence.
Company Financial Statements.
Data for Northern Indiana Public Service Company is from FERC financial Report Form Form No. 1 at PDF 21.

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Seven Natural Gas Companies	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth in EPS (3)	[6] Adjusted Dividend Yield (4)	[7] Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.06 %	7.00 %	7.50 %	7.44 %	7.31 %	2.14 %	9.45 %
Chesapeake Utilities Corporation	2.13	8.00	NA	9.15	8.58	2.22	10.80
New Jersey Resources Corporation	4.07	5.00	NA	7.90	6.45	4.20	10.65
NiSource Inc.	2.65	9.50	7.70	8.51	8.57	2.76	11.33
Northwest Natural Holding Company	4.56	6.50	NA	5.67	6.08	4.70	10.78
ONE Gas, Inc.	3.43	4.50	5.80	6.36	5.55	3.53	9.08
Southwest Gas Holdings, Inc.	3.15	10.00	9.70	12.66	10.79	3.32	14.11 (6)
						Average	10.35 %
						Median	10.71 %
						Average of Mean and Median	10.53 %

NA= Not Available

Notes:

(1) Indicated dividend at 10/31/2025 divided by the average closing price of the last 60 trading days ending 10/31/2025 for each company.
(2) From pages 2 through 8 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.06% x (1+(1/2 x 7.31%)) = 2.14%.
(5) Column 5 + Column 6.
(6) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 10/31/2025
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 165.04 | P/E RATIO 21.7 (Trailing: 22.7 Median: 20.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 3 Raised 1/17/25
SAFETY 1 Raised 6/6/14
TECHNICAL 4 Lowered 8/22/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$143-$208	$176 (5%)

2028-30 PROJECTIONS

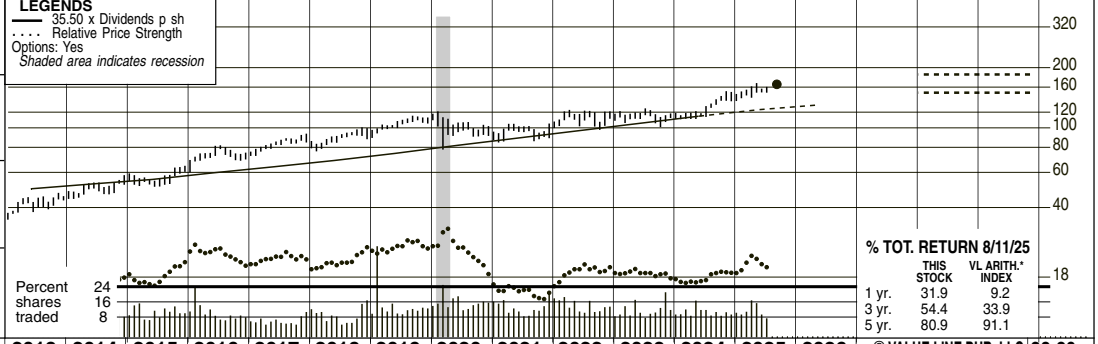
	Price	Gain	Ann'l Total Return
High	185	(+10%)	*5%*
Low	150	(-10%)	*Nil*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	357	421	458
to Sell	315	294	320
Hld's(000)	162641	171243	157845

	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	152.6	167.5
High:												
Low:	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5	136.2

LEGENDS
35.50 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	26.83	*29.15*	*29.05*	Revenues per sh [A]	*34.05*
4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	11.03	*12.00*	*12.70*	"Cash Flow" per sh	*14.75*
1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.83	*7.35*	*7.75*	Earnings per sh [AB]	*9.35*
1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	*3.48*	*3.68*	Div'ds Decl'd per sh [C]■	*4.45*
5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	18.92	*23.00*	*22.75*	Cap'l Spending per sh	*21.60*
23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	78.31	*84.80*	*86.25*	Book Value per sh	*97.30*
92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.26	*161.00*	*167.00*	Common Shs Outst'g [D]	*185.00*
12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	17.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	.90			Relative P/E Ratio	*1.00*
5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	2.7%			Avg Ann'l Div'd Yield	*2.7%*
4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4165.2	*4690*	*4850*	Revenues ($mill) [A]	*6300*
315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1042.9	*1185*	*1300*	Net Profit ($mill)	*1730*
38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.6%	*19.0%*	*19.5%*	Income Tax Rate	*25.0%*
7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	25.0%	*25.3%*	*26.8%*	Net Profit Margin	*27.5%*
43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	39.3%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	60.7%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	20018	*22750*	*24000*	Total Capital ($mill)	*30000*
7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	22204	*24500*	*26000*	Net Plant ($mill)	*32000*
6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	5.7%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	*8.5%*	*9.0%*	Return on Com Equity	*9.5%*
4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
51%	50%	50%	48%	48%	49%	49%	49%	49%	47%	*47%*	*47%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 6/30/25
Total Debt $9000.8 mill. **Due in 5 Yrs** $1185.0 mill.
LT Debt $8980.6 mill. **LT Interest** $190.0 mill.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Leases, Uncapitalized Annual rentals $43.2 mill.

Pfd Stock None

Pension Assets-9/24 $595.2 mill.
Oblig. $470.9 mill.
Common Stock 160,523,571 shs.
as of 8/1/25

MARKET CAP: $26.5 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	15.4	307.3	709.4
Other	870.4	825.0	842.6
Current Assets	885.8	1132.3	1552.0
Accts Payable	336.1	445.4	397.6
Debt Due	253.4	9.9	20.2
Other	763.1	750.6	712.7
Current Liab.	1352.6	1205.9	1130.5
Fix. Chg. Cov.	1059%	914%	940%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.0%	2.0%	*3.0%*
"Cash Flow"	7.0%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.5%	9.0%	*7.0%*
Book Value	10.0%	11.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	701.5	658.0	4165.2
2025	1176.0	1950.5	838.8	*724.7*	*4690*
2026	*1210*	*2030*	*825*	*785*	*4850*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.08	.86	6.83
2025	2.23	3.03	1.16	*.93*	*7.35*
2026	*2.35*	*3.16*	*1.23*	*1.01*	*7.75*

Calendar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805	.805	.87	3.29
2025	.87	.87	.87		

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over 3.3 million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2024: 68.8%, residential; 27.1%, commercial; 2.7%, industrial; and 1.4% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/24 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

It appears that Atmos Energy's long streak of bottom-line growth will continue in fiscal 2025 (concludes September 30th). During the first nine months, earnings per share advanced almost 7%, to $6.42, compared to the prior-year's $6.01 tally. That was driven by better performances from both the distribution unit and pipeline & storage division. But the company's results were held back, to a certain extent, by a rise in bad-debt expense, depreciation, and property taxes. Still, it seems that, for the full year, profits will finish around $7.35 a share. That would indicate a nearly 8% advance from fiscal 2024's $6.83 total. Regarding fiscal 2026, per-share profits stand to grow an additional 5% or so, to $7.75, assuming further expansion of operating margins.

Finances are sound. When the June interim ended, cash and equivalents stood at $709.4 million. Furthermore, long-term debt seemed very manageable (40% of total capital) and short-term borrowings were only $20.2 million. Also, $5.8 billion in common stock and/or debt securities remained available for issuance (out of $8.0 billion) under a shelf registration statement expiring in December, 2027. Finally, Atmos had undrawn credit facilities aggregating $3.1 billion.

Capital expenditures for fiscal 2025 are anticipated to be roughly $3.7 billion. That is some 26% higher than the previous-year level of around $2.9 billion. Similar to fiscal 2024, a meaningful portion of the resources are being utilized to enhance the safety and reliability of the company's natural gas distribution and transmission systems. Leadership adds that it projects total capital spending from fiscal 2025 through fiscal 2029 to lie in the neighborhood of $24 billion. A considerable amount of the investments will continue to be deployed to where they are currently. If the balance sheet stays in good condition, Atmos should have minimal difficulty accomplishing those objectives.

These shares hold unspectacular long-term total return potential. The dividend yield looks unexciting versus the average of *Value Line's* Natural Gas Utility Industry. Also, at the recent quotation, capital gains potential out to 2028-2030 is quite limited.

Frederick L. Harris, III *August 22, 2025*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Nov. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	100

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CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 123.61 | P/E RATIO 20.6 (Trailing: 22.0 Median: 23.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 4 Lowered 6/20/25
SAFETY 2 New 6/5/15
TECHNICAL 3 Lowered 8/15/25
BETA .70 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$107-$175	$141 (15%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+30%)	*9%*
Low	120	(-5%)	*2%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	139	151	164
to Sell	116	127	124
Hld's(000)	23010	23287	20423

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	52.7	61.1	70.0	86.4	93.4	98.6	111.4	146.1	146.3	132.9	134.2	136.7						
Low:	37.5	44.4	52.3	63.0	66.4	77.6	69.5	99.6	105.8	83.8	98.3	115.1						

Target Price Range 2028 2029 2030

% TOT. RETURN 8/11/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.8	9.2
3 yr.	-0.6	33.9
5 yr.	59.9	91.1

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	32.28	38.37	30.16	34.38	*38.35*	*42.90*	Revenues per sh	*65.40*
	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	8.28	8.87	6.87	8.05	*9.40*	*10.85*	"Cash Flow" per sh	*14.05*
	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	4.73	4.97	4.73	5.26	*5.85*	*6.30*	Earnings per sh [A]	*8.00*
	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	2.03	2.25	2.46	*2.65*	*2.82*	Div'ds Decl'd per sh [B]■	*3.40*
	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	10.59	7.23	8.48	15.52	*16.05*	*16.65*	Cap'l Spending per sh	*15.55*
	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	43.85	46.94	56.04	60.71	*67.05*	*72.40*	Book Value per sh	*77.50*
	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	16.40	17.46	17.66	17.74	22.24	22.90	*24.00*	*24.00*	Common Shs Outst'g [C]	*26.00*
	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	24.7	21.6	25.6	25.8	24.3	21.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	1.38	1.49	1.36	1.13			Relative P/E Ratio	*.95*
	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%	1.6%	2.0%	2.2%			Avg Ann'l Div'd Yield	*2.4%*
							459.2	498.9	617.6	717.5	479.6	488.2	570.0	680.7	670.6	787.2	*920*	*1030*	Revenues ($mill)	*1700*
							40.2	44.7	43.8	56.6	61.1	70.6	83.5	88.4	87.2	118.6	*137*	*150*	Net Profit ($mill)	*215*
							39.5%	38.8%	39.5%	27.1%	25.6%	25.0%	25.9%	27.4%	24.4%	26.7%	*27.0%*	*27.0%*	Income Tax Rate	*29.0%*
							8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	14.6%	13.0%	13.0%	15.1%	*14.9%*	*14.6%*	Net Profit Margin	*12.6%*
							29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	41.5%	41.0%	48.8%	47.6%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*48.0%*
							70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	58.5%	59.0%	51.2%	52.4%	*55.0%*	*55.0%*	Common Equity Ratio	*52.0%*
							507.5	583.0	683.7	834.5	1001.7	1205.6	1324.0	1411.2	2433.2	2651.9	*2925*	*3160*	Total Capital ($mill)	*3875*
							855.0	986.7	1126.0	1384.0	1463.8	1601.2	1744.9	1810.5	2456.4	2735.9	*3100*	*3350*	Net Plant ($mill)	*4150*
							8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	7.1%	7.1%	4.3%	5.8%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
							11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	7.0%	8.5%	*8.5%*	*8.5%*	Return on Shr. Equity	*10.5%*
							11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	7.0%	8.5%	*8.5%*	*8.5%*	Return on Com Equity	*10.5%*
							6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	6.7%	6.4%	3.8%	4.6%	*4.5%*	*4.5%*	Retained to Com Eq	*6.5%*
							40%	39%	45%	39%	40%	38%	38%	40%	46%	46%	*46%*	*45%*	All Div'ds to Net Prof	*41%*

CAPITAL STRUCTURE as of 6/30/25
Total Debt $1520.4 mill. **Due in 5 Yrs** $780.0 mill.
LT Debt $1249.6 mill. **LT Interest** $68.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x) (45% of Cap'l)
Leases, Uncapitalized Annual rentals $2.6 mill.
Pfd Stock None
Pension Assets-12/24 $49.1 mill.
Oblig. $47.0 mill.
Common Stock 23,544,479 shs.
as of 8/4/25

MARKET CAP: $2.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	4.9	7.9	1.5
Other	180.8	196.4	190.8
Current Assets	185.7	204.3	192.3
Accts Payable	77.5	78.3	69.1
Debt Due	198.4	222.0	270.8
Other	110.5	119.1	119.9
Current Liab.	386.4	419.4	459.8
Fix. Chg. Cov.	514%	393%	405%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.0%	-1.5%	*11.5%*
"Cash Flow"	6.0%	5.5%	*10.0%*
Earnings	8.5%	8.5%	*8.0%*
Dividends	8.5%	10.0%	*7.0%*
Book Value	11.0%	11.5%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	222.9	139.5	131.1	187.2	680.7
2023	218.1	135.6	131.5	185.4	670.6
2024	245.7	166.3	160.1	215.1	787.2
2025	298.7	192.8	*188*	*240.5*	*920*
2026	*330*	*220*	*215*	*265*	*1030*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	2.08	.88	.54	1.47	4.97
2023	2.04	.90	.53	1.26	4.73
2024	2.07	.82	.78	1.60	5.26
2025	2.21	1.02	*.85*	*1.77*	*5.85*
2026	*2.35*	*1.04*	*.98*	*1.93*	*6.30*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.44	.44	.48	.48	1.84
2022	.48	.48	.535	.535	2.03
2023	.535	.535	.59	.59	2.25
2024	.59	.59	.64	.64	2.46
2025	.64	.64	.685		

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2024: Regulated Energy, 74.1%; Unregulated Energy, 29.0%; Other, d3.1%. Officers and directors own 1.5% of common stock; BlackRock, 16.1% (3/25 Proxy). Chairman and CEO: Jeffry Householder. Inc.: DE. Address: 500 Energy Lane, Dover, DE 19901. Tel.: (302) 734-6799. Internet: www.chpk.com.

It's been a prosperous year, so far, for Chesapeake Utilities Corporation. In fact, through the first six months, earnings per share climbed 11.8%, to $3.23, relative to the $2.89 tally that was registered for the same period in 2024. One supporting factor was increased customer consumption stemming from colder temperatures across the Ohio and Mid-Atlantic service territories. Too, there were benefits from pipeline expansion projects. Other pluses included contributions from regulated infrastructure programs and rate changes associated with recent rate-case activities. If there are no major setbacks during the second half, it seems that the company's bottom line will finish in the neighborhood of $5.85 a share for the entire year. This would indicate an 11% advance from 2024's $5.26 total. Turning to 2026, per-share profits might well grow another 8%, to $6.30, as operating margins widen further.

Corporate finances are sound. When the June interim concluded, cash and equivalents resided at $1.5 million. Moreover, long-term debt appeared reasonable (45% of total capital) and short-term borrowings were not a big hurdle. Elsewhere, $197.1 million was available, out of $450.0 million, under a revolving credit facility.

This year's capital spending budget is now expected to be between $375 million and $425 million. (It was raised from the earlier $325 million-$375 million target due to advances on various projects.) The majority of the funds are being deployed to the Regulated Energy division, with a focus on the natural gas distribution and transmission segments. Also, Chesapeake looks for total capital expenditures to lie in the range of $1.5 billion and $1.8 billion for the five-year period between 2024 and 2028. All things considered, we think those goals can be reached, assuming that the balance sheet stays in good shape, of course.

The equity, ranked 4 (Below Average) for Timeliness, has unspectacular total return potential out to 2028-2030. Its dividend yield is not alluring versus those of other Natural Gas Utility stocks in the *Value Line* universe. Furthermore, long-term capital appreciation possibilities are limited at the recent quotation.

Frederick L. Harris, III *August 22, 2025*

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	80
Earnings Predictability	100

(A) Diluted shrs. Excludes nonrecurring gains: '15, 6¢; '17, 87¢; '22, 8¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Next earnings report due early Nov. Quarters for '24 don't add up to total due to rounding. **(B)** Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available. **(C)** In millions, adjusted for split.

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE **47.20** | P/E RATIO **16.1** (Trailing: 11.7 Median: 17.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **4.0%** | **VALUE LINE**

TIMELINESS 4 Lowered 7/18/25
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Lowered 7/25/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$41-$66	$54 (15%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+60%)	*15%*
Low	55	(+15%)	*8%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	196	215	218
to Sell	134	135	165
Hld's(000)	88596	91465	74916

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	51.9	50.8						
Low:	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4	43.8						

LEGENDS
— Dividend divided by div'd yield
. . . . Relative Price Strength
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

Target Price Range 2028 | 2029 | 2030
120 100 80 64 48 32 24 20 16 12 8

% TOT. RETURN 8/11/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.3	9.2
3 yr.	15.7	33.9
5 yr.	74.3	91.1

Percent shares traded 30 20 10

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.19	20.12	18.06	*19.80*	*19.60*	Revenues per sh [A]	*21.45*
	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.84	4.28	4.59	*5.10*	*5.10*	"Cash Flow" per sh	*6.25*
	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.71	2.95	*3.25*	*3.15*	Earnings per sh [B]	*3.90*
	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.71	*1.80*	*1.95*	Div'ds Decl'd per sh [C]■	*2.20*
	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.81	5.13	5.26	*6.50*	*5.75*	Cap'l Spending per sh	*6.50*
	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.88	20.40	22.12	*24.75*	*25.35*	Book Value per sh [D]	*27.65*
	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	96.25	97.58	99.46	*101.00*	*102.00*	Common Shs Outst'g [E]	*105.00*
	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.6	14.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.95	.98	.98	.77			Relative P/E Ratio	*.95*
	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	3.9%			Avg Ann'l Div'd Yield	*3.3%*
							2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	1796.5	*2000*	*2000*	Revenues ($mill) [A]	*2250*
							153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	264.7	290.8	*330*	*320*	Net Profit ($mill)	*410*
							26.3%	15.5%	17.2%	--	--	--	10.3%	22.0%	15.9%	23.0%	*21.5%*	*22.0%*	Income Tax Rate	*22.0%*
							5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.5%	16.2%	*16.4%*	*16.1%*	Net Profit Margin	*18.2%*
							43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	56.7%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
							56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	43.3%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
							1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5079.9	*5550*	*5750*	Total Capital ($mill)	*6450*
							2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5403.2	*5700*	*5900*	Net Plant ($mill)	*6800*
							8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.8%	5.5%	5.7%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
							13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.0%*	*12.5%*	Return on Shr. Equity	*14.0%*
							13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	*13.0%*	*12.5%*	Return on Com Equity	*14.0%*
							7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.7%	5.7%	*6.0%*	*4.5%*	Retained to Com Eq	*6.0%*
							50%	60%	59%	40%	59%	60%	56%	53%	58%	58%	*55%*	*62%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 6/30/25
Total Debt $3383.4 mill. **Due in 5 Yrs** $660 mill.
LT Debt $3020.6 mill. **LT Interest** $135 mill.
Incl. $8.4 mill. capitalized leases.

Pension Assets-9/24 $641 mill.
Oblig. $624 mill.

Pfd Stock None

Common Stock 100,451,372 shs.
as of 8/1/25

MARKET CAP: $4.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	1.0	1.0	.9
Other	531.1	553.6	561.4
Current Assets	532.1	554.6	562.3
Accts Payable	203.1	169.2	138.7
Debt Due	368.3	480.8	362.8
Other	235.2	237.8	237.6
Current Liab.	806.6	887.8	739.1
Fix. Chg. Cov.	331%	480%	620%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	-4.5%	-5.0%	*2.5%*
"Cash Flow"	7.0%	6.5%	*5.0%*
Earnings	5.5%	5.0%	*5.0%*
Dividends	7.0%	7.0%	*5.0%*
Book Value	7.0%	5.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	675.9	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	275.6	395.8	1796.5
2025	488.4	913.0	298.9	***299.7***	***2000***
2026	***490***	***915***	***300***	***295***	***2000***

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2022	.69	1.36	d.04	.49	2.50
2023	1.14	1.16	.10	.31	2.71
2024	.74	1.41	d.09	.89	2.95
2025	1.28	1.78	.06	***.12***	***3.25***
2026	***1.10***	***1.65***	***.10***	***.30***	***3.15***

Calendar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42	.42	.45	1.71
2025	.45	.45	.45		

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 583,000 cust. at 9/30/24. Fiscal 2024 volume: 158 bill. cu. ft. (16% interruptible, 41% residential, commercial & firm transportation, 43% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2024 dep. rate: 3.2%. Has 1,370 empls. Off./dir. own less than 1% of common; BlackRock, 17.3%; Vanguard, 11.9% (12/24 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted a better-than-expected fiscal third-quarter showing. (Year ends September 30th.) During the three-month term, the company posted earnings per share of $0.06, versus a loss of $0.09 a year ago, primarily due to a strong performance from financial hedging instruments. Year-to-date earnings reached $3.12 per share, up roughly 55% on stronger regulated utility margins after a recent rate case was resolved, a one-time $0.30 per share benefit from the sale of the residential solar portfolio, improved storage and transportation results, and contributions from winter storms. The results are strong overall, with New Jersey Resources on track to deliver a record earnings year, even as some gains may not be recurring.

Growth over the next few years will likely occur on multiple fronts. Investors should watch for execution in three areas, regulated utility growth, solar build-out, and potential storage expansion projects. At New Jersey Natural Gas, steady customer additions in core NJ counties, combined with safety and reliability capital projects should continue to compound on the company's regulated earnings base. Meantime, Clean Energy Ventures maintains a deep development pipeline, though with recent policy actions, this is worth monitoring as the company will need to be more selective about its capital plan. Finally, storage additions, particularly at Leaf River, could add long-lived fee-based cash flows tied to power market balancing needs. Across the portfolio, interest-rate moves and construction market trends remain near-term factors.

New Jersey Resources is well positioned for the long-term. Looking three- to five-years out, the strategy remains anchored in regulated utility earnings. Strong regional economic trends and rising electrification demand from data centers and peak-hour fluctuations increase the need for flexible power balancing resources, which supports NJR's strategic model. These trends should be sustained adding to our growth outlook.

The stock has some investment appeal. Though untimely, the equity may well interest conservative income-oriented accounts.

Earl B. Humes *August 22, 2025*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due late November.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2024: $612.6 million, $6.16/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	65

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NISOURCE INC. NYSE-NI

RECENT PRICE **42.15** | P/E RATIO **22.0** (Trailing: 22.3 Median: 21.0) | RELATIVE P/E RATIO **1.22** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/2/25
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Lowered 8/1/25
BETA .80 (1.00 = Market)

18-Month Target Price Range

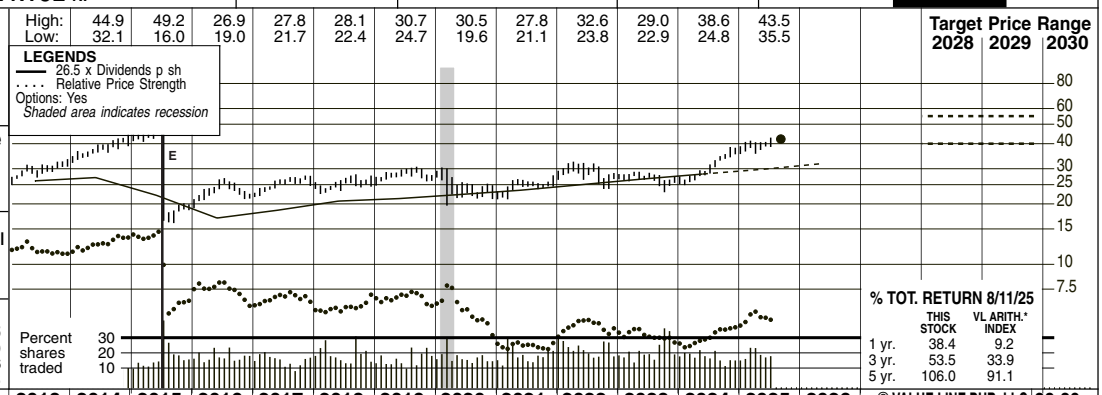
Low-High	Midpoint (% to Mid)
$30-$48	$39 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	*10%*
Low	40	(-5%)	*2%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	334	383	429
to Sell	286	288	296
Hld's(000)	484273	493671	437986



2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	© VALUE LINE PUB. LLC	28-30
24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.20	12.31	11.61	*12.50*	*12.60*	Revenues per sh	*15.60*
2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.56	3.63	3.97	*4.10*	*4.15*	"Cash Flow" per sh	*5.30*
.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	1.75	*1.90*	*2.00*	Earnings per sh [A]	*2.55*
.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	1.06	*1.12*	*1.20*	Div'd Decl'd per sh [B] ■	*1.44*
2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	5.35	5.91	5.56	*5.50*	*6.00*	Cap'l Spending per sh	*7.00*
17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	14.63	17.40	22.71	*25.70*	*25.75*	Book Value per sh [C]	*29.85*
276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	405.30	412.14	447.38	469.82	*480.00*	*500.00*	Common Shs Outst'g [D]	*525.00*
14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	17.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.97	1.13	.93	.97			Relative P/E Ratio	*1.05*
7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	3.5%			Avg Ann'l Div'd Yield	*3.0%*
4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	5455.1	*6000*	*6300*	Revenues ($mill)	*8200*
198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	798.6	*910*	*1000*	Net Profit ($mill)	*1340*
41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	16.5%	17.8%	17.9%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	--	3.0%	3.3%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	57.2%	54.0%	*54.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	35.3%	40.3%	46.0%	*46.0%*	*45.0%*	Common Equity Ratio	*45.0%*
9792.0	10129	11832	12856	13843	14972	16131	17099	19325	24294	*26800*	*28600*	Total Capital ($mill)	*35000*
12112	13068	14360	15543	16912	16620	17882	19843	22275	27044	*30000*	*32000*	Net Plant ($mill)	*39000*
4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	3.5%	*3.5%*	*3.5%*	Return on Total Cap'l	*4.0%*
5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	8.6%	7.1%	*7.5%*	*7.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	10.7%	7.1%	7.5%	*7.5%*	*8.0%*	Return on Com Equity	*8.5%*
NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	3.6%	2.8%	3.0%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
NMF	63%	NMF	60%	64%	67%	64%	64%	63%	61%	*59%*	*60%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 6/30/25
Total Debt $15756 mill. **Due in 5 Yrs** $8306 mill.
LT Debt $14474 mill. **LT Interest** $550 mill. (57% of Cap'l)

Leases, Uncapitalized Annual rentals $10.0 mill.
Pension Assets-12/24 $1.3 bill. **Oblig.** $1.3 bill.

Common Stock 470,855,009 shs.
as of 7/30/25

MARKET CAP: $19.8 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	2245.4	156.6	335.4
Other	2254.0	1923.6	443.2
Current Assets	4499.4	2080.2	778.6
Accts Payable	749.4	863.1	683.9
Debt Due	3072.4	1885.8	1282.2
Other	1443.3	1364.5	1446.2
Current Liab.	5265.1	4113.4	3412.3
Fix. Chg. Cov.	225%	280%	575%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	-3.5%	-1.5%	*5.5%*
"Cash Flow"	1.0%	6.5%	*5.5%*
Earnings	1.0%	10.5%	*9.5%*
Dividends	--	6.0%	*4.5%*
Book Value	-2.0%	3.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1873	1183	1089	1704	5850.6
2023	1966	1090	1027	1422	5505.4
2024	1706	1085	1076	1588	5455.1
2025	2183	1283	*1185*	*1349*	*6000*
2026	*2290*	*1345*	*1245*	*1420*	*6300*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	.21	.20	.49	1.75
2025	.98	.22	*.20*	*.50*	*1.90*
2026	*1.00*	*.30*	*.20*	*.50*	*2.00*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265	.265	.265	1.06
2025	.28	.28	.28		

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 492,690 electric in Indiana, 3.3 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 34%; gas, 63%; other, 3%. Generating capacity, fossil feuls 56%; renewables, 44%. 2024 reported depreciation rates: 3.0% electric, 2.6% gas. Has 7,746 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource posted solid second-quarter results, driven by rates, customer growth, and efficiency gains. The profit picture was mostly steady, with earnings of $0.22 per share advancing a penny over the year-ago figure, though this was below our target. Results benefited from favorable regulatory outcomes in Virginia and Indiana, as well as modest customer growth, and operational efficiencies from new technology implementations. The company's infrastructure modernization initiatives continue to advance, with leak detection and digitalization program rollouts exceeding internal targets. Broader economic tailwinds in its service territories, such as above-average population growth in Columbus, contributed nicely. However, operating costs and interest expenses offset these effects on the bottom line.

Profit comparisons through the back half of 2025 look challenging. We're expecting a mostly flat earnings performance throughout the year with almost all of the bottom line's 9% growth coming from the first quarter's strong result. The utility only has one relatively small rate case expected to be approved in the near term, while maintenance and other operating costs continue to rise. However, NiSource won't be staying idle. Much of the company's focus this year centers around continuing progress on its 5-year $19 billion capital plan, and the ongoing development of data center infrastructure. While actual contracts with data center counterparties are still being negotiated, the company is planning its efforts to meet its power delivery goals in 2025.

NiSource is well positioned for its long-term growth objectives, as a key enabler of the energy transition in the Midwest and Mid-Atlantic. The company's regulated utility businesses, diversified across six states and two energy types, provides a good foundation for steady earnings and rate base growth. And, the emergence of high-load customers is expected to reshape and supplement its market opportunities significantly in the coming years.

Much of these strengths are baked in at the recent quotation, leaving the stock's upside quite limited.

Earl B. Humes *August 22, 2025*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '15, (30¢); '18, ($1.48). Next egs. report due late October. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '24: $1485.9 million, $3.16/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

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N.W. NATURAL NYSE-NWN

RECENT PRICE **40.38** | P/E RATIO **13.6** (Trailing: 13.8 Median: 24.0) | RELATIVE P/E RATIO **0.75** | DIV'D YLD **4.9%** | **VALUE LINE**

TIMELINESS 4 Lowered 8/15/25
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Lowered 7/25/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$52	$43 (5%)

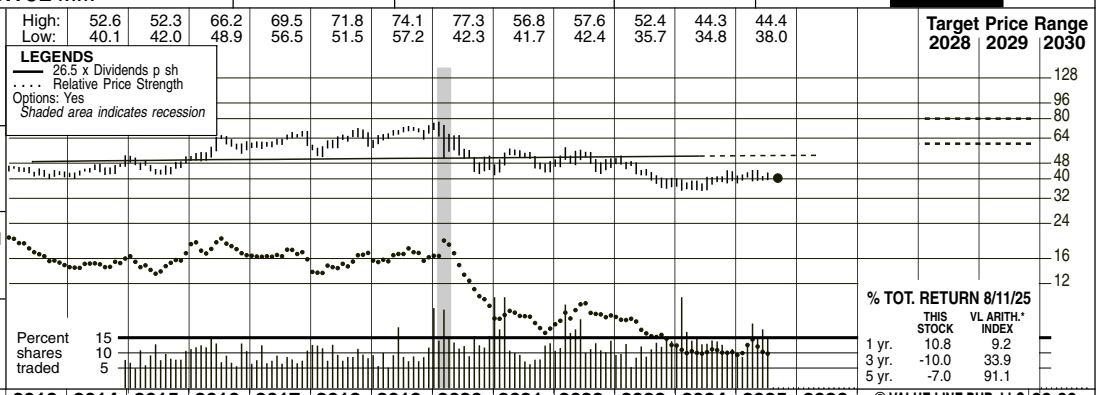
2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+100%)	*22%*
Low	60	(+50%)	*14%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	119	142	149
to Sell	118	96	100
Hld's(000)	37328	37493	31667

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	44.3	44.4						
Low:	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.8	38.0						
Revenues per sh	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	28.67	*32.15*	*31.10*
"Cash Flow" per sh	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	5.68	*6.50*	*6.55*
Earnings per sh [A]	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	2.33	*2.95*	*3.00*
Div'ds Decl'd per sh [B]■	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	1.95	*1.96*	*1.97*
Cap'l Spending per sh	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	8.80	*9.50*	*10.00*
Book Value per sh [D]	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.09	34.12	34.45	*36.65*	*37.75*
Common Shs Outst'g [C]	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	40.22	*42.00*	*45.00*
Avg Ann'l P/E Ratio	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	16.6	*Bold figures are Value Line estimates*	
Relative P/E Ratio	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.05	1.13	.92	.92		
Avg Ann'l Div'd Yield	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	5.1%		
Revenues ($mill)							723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	1153.0	*1350*	*1400*
Net Profit ($mill)							53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	90.6	*125*	*135*
Income Tax Rate							40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.6%	25.6%	*25.0%*	*25.0%*
Net Profit Margin							7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	7.9%	*9.2%*	*9.6%*
Long-Term Debt Ratio							42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	54.8%	*55.0%*	*55.0%*
Common Equity Ratio							57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	45.2%	*45.0%*	*45.0%*
Total Capital ($mill)							1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.3	3064.8	*3420*	*3775*
Net Plant ($mill)							2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.1	3672.3	*3985*	*4300*
Return on Total Cap'l							5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	4.7%	4.9%	3.0%	*3.5%*	*3.5%*
Return on Shr. Equity							6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*6.5%*	*8.0%*	*8.0%*
Return on Com Equity							6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	6.5%	*8.0%*	*8.0%*
Retained to Com Eq							.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.0%	2.1%	.9%	*2.0%*	*2.0%*
All Div'ds to Net Prof							92%	87%	NMF	76%	82%	79%	71%	73%	72%	84%	*66%*	*66%*



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CAPITAL STRUCTURE as of 6/30/25
Total Debt $2386 mill. **Due in 5 Yrs** $1175 mill.
LT Debt $2087 mill. **LT Interest** $120 mill.

Pension Assets-12/24 $284.1 mill.
Oblig. $405.6 mill.

Pfd Stock None

Common Stock 40,938,429 shares
as of 7/25/25

MARKET CAP $1.7 billion (Small Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	32.9	38.5	102.6
Other	568.5	519.3	363.5
Current Assets	601.4	557.8	466.1
Accts Payable	145.4	133.3	116.8
Debt Due	240.7	200.9	298.9
Other	310.8	314.8	268.2
Current Liab.	696.9	649.0	683.9
Fix. Chg. Cov.	240%	410%	440%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '28-'30
Revenues	- -	3.5%	*4.5%*
"Cash Flow"	1.5%	9.5%	*5.0%*
Earnings	1.0%	25.0%	*6.5%*
Dividends	1.0%	.5%	*.5%*
Book Value	2.0%	3.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	211.7	136.9	370.9	1153.0
2025	494.3	236.2	*160*	*459.5*	*1350*
2026	*515*	*245*	*165*	*475*	*1400*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	d.07	d.71	1.41	2.33
2025	2.28	.01	*d.60*	*1.26*	*2.95*
2026	*2.30*	*.Nil*	*d.65*	*1.35*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488	.488	.49	1.95
2025	.49	.49	.49		

BUSINESS: Northwest Natural Holding Co. distributes natural gas to more than 800,000 customers in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Gas margin breakdown: residential, 65%; commercial, 25%; industrial, 6%; other, 4%. Also operates water and wastewater services across six states. Employs 1,452. BlackRock Inc. owns 16.1% of shares; Vanguard, 10.8%; Off./Dir., .93% (4/25 proxy). CEO: Justin B. Palfreyman. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural has been steadily improving its operating results of late. The utility has continued its streak of top- and bottom-line advances for three consecutive quarters in June. Revenues reached $236 million, while earnings per share landed just above breakeven, at $0.01, compared to a $0.07 loss in the year before. Higher margins from new rates in Oregon, recent acquisitions, and continued customer growth all contributed. However, higher operating, depreciation and interest costs tempered some of these gains, and earnings were slightly weaker than we had expected. It's worth noting that broader market conditions were generally stable for regulated utilities, though higher financing costs and regional housing slowdowns present headwinds.

We have lowered our 2025 profit outlook slightly. Management has reaffirmed its guidance for earnings per share of $2.75 to $2.95, expecting steady contributions from its gas, water, and renewable segments. We've cut our target by $0.05 to match the top end of management's range, at $2.95, owing to the recent quarter's weaker-than-expected profitability and the likelihood of continued cost pressures. The natural gas franchise will remain a ballast for the company, with plenty of investment planned in the pipeline. To this point, we've raised our capital expenditure target to $500 million in 2025.

The next few years will be marked by strategic market expansion. The company's growth strategy hinges on a diversified regulated utility model spanning gas, water, and renewable natural gas. Continued water utility consolidation and high growth in Texas markets could meaningfully shift the earnings mix away from its traditional Oregon gas base. However, this carries greater regulatory and execution risk. The company's long-term outlook appears mostly stable, although this depends on disciplined capital deployment and future rate case outcomes.

The stock offers good total-return prospects at the current juncture, with a better overall risk profile than many of its industry peers. Income investors, in particular, may appreciate the stock's high yield. The issue is untimely, however.

Earl B. Humes *August 22, 2025*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early November.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2024: $184 million, $4.60/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	25

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 75.13 | P/E RATIO 17.4 (Trailing: 17.9 Median: 21.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 8/22/25
SAFETY 2 New 6/2/17
TECHNICAL 3 Lowered 8/22/25
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$63-$95	$79 (5%)

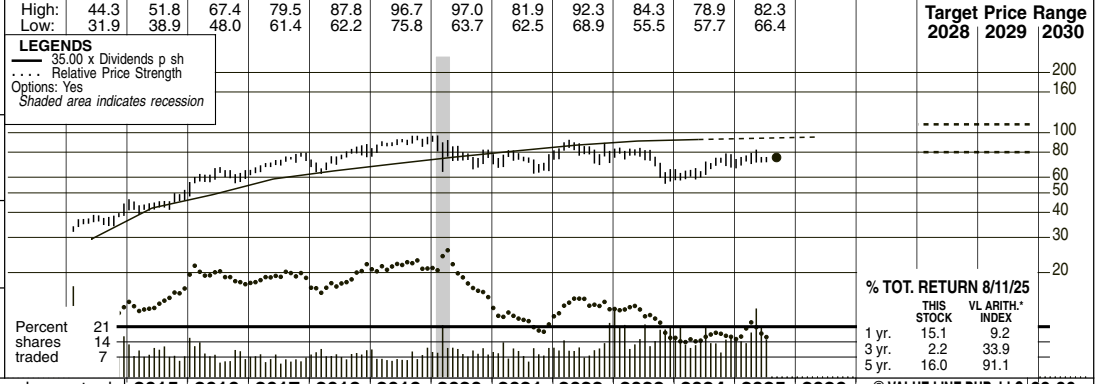
2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+45%)	*13%*
Low	80	(+5%)	*5%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	152	174	188
to Sell	146	124	148
Hld's(000)	62020	63204	54991

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	78.9	82.3
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7	66.4



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	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues per sh	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	34.80	*38.45*	*39.70*
"Cash Flow" per sh	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	8.68	*9.55*	*9.95*
Earnings per sh A	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	3.91	*4.35*	*4.55*
Div'ds Decl'd per sh B■	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	2.64	*2.68*	*2.72*
Cap'l Spending per sh	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	11.74	*11.65*	*11.60*
Book Value per sh	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	51.85	*53.75*	*55.50*
Common Shs Outst'g C	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	59.88	*61.50*	*63.00*
Avg Ann'l P/E Ratio	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	17.0	*Bold figures are Value Line estimates*	
Relative P/E Ratio	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.15	1.01	.90		
Avg Ann'l Div'd Yield	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	4.0%		
Revenues ($mill)	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	2083.6	*2365*	*2500*
Net Profit ($mill)	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	222.9	*265*	*285*
Income Tax Rate	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	14.0%	*18.0%*	*18.0%*
Net Profit Margin	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	10.7%	*11.2%*	*11.4%*
Long-Term Debt Ratio	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	43.5%	*43.0%*	*43.0%*
Common Equity Ratio	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	56.5%	*57.0%*	*57.0%*
Total Capital ($mill)	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	5489.8	*5800*	*6135*
Net Plant ($mill)	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	6645.9	*7050*	*7400*
Return on Total Cap'l	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	5.4%	*6.0%*	*6.0%*
Return on Shr. Equity	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.0%*
Return on Com Equity	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.0%*
Retained to Com Eq	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	2.4%	*3.0%*	*3.0%*
All Div'ds to Net Prof	53%	52%	55%	56%	56%	58%	60%	60%	62%	67%	*62%*	*60%*

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 6/30/25
Total Debt $3273.1 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $2370.9 mill. **LT Interest** $145.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $5.9 mill.
Pfd Stock None
Pension Assets-12/24 $904.9 mill.
Oblig. $882.1 mill.
Common Stock 59,998,366 shs.
as of 7/28/25
MARKET CAP: $4.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	18.8	58.0	20.5
Other	746.4	871.9	660.8
Current Assets	765.2	929.9	681.3
Accts Payable	278.1	261.3	131.0
Debt Due	888.9	943.6	902.2
Other	310.2	253.4	268.8
Current Liab.	1477.2	1458.3	1302.0
Fix. Chg. Cov.	390%	325%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	1.5%	6.0%	*5.0%*
"Cash Flow"	6.5%	6.0%	*4.0%*
Earnings	7.0%	4.5%	*4.5%*
Dividends	12.0%	7.0%	*2.0%*
Book Value	3.5%	5.0%	*2.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	354.1	340.4	630.8	2083.6
2025	935.2	423.7	*353*	*653.1*	*2365*
2026	*933*	*452*	*385*	*730*	*2500*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.48	.34	1.34	3.91
2025	1.98	.53	*.42*	*1.42*	*4.35*
2026	*1.96*	*.64*	*.49*	*1.46*	*4.55*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66	.66	.66	2.64
2025	.67	.67	.67		

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 149 Bcf of natural gas supply in 2024, compared to 160 Bcf in 2023. Total volumes delivered by customer (fiscal 2024): transportation, 60.7%; residential, 28.6%; commercial & industrial, 10.1%; other, .6%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 8.0%; officers and directors, 1.2% (4/25 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas is having a good year, thus far. Through the first half, per-share profits climbed 12.6%, to $2.51, versus 2024's $2.23 figure. That partially reflected benefits from new rates. Another supporting factor was higher residential sales, due primarily to net customer growth in both Texas and Oklahoma. But greater depreciation & amortization expense, given additional capital investments, provided somewhat of an offset to the company's solid performance. Also, employee-related costs rose stemming, to a certain extent, from planned investments in the workforce. Nonetheless, it appears that full-year earnings will advance at a low-double-digit percentage rate, to $4.35 a share, relative to 2024's $3.91 tally. Regarding 2026, the bottom line may grow at a slower (though still respectable) 5% clip, to $4.55 per share, because of the tough comparison.

Business prospects out to 2028-2030 look promising. The company is the leading natural gas distributor, as measured by number of customers, in both Kansas and Oklahoma, and holds the number-three position in Texas. Furthermore, we believe that these markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, thanks to the solid finances, ONE Gas ought to continue to meet its commitments with little trouble. So, annual earnings-per-share increases stand to range between 4% and 6% over that time frame.

There are risk factors to bear in mind, however. The company's lack of geographic diversification leaves it somewhat more vulnerable to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, such as propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate events can take a major toll on profits if not sufficiently covered by insurance.

Conservative, income-minded investors may want to take a look at the stock. Its dividend yield is decent relative to those of other equities in *Value Line's* Natural Gas Utility category. Consider, also, the 2 (Above Average) Safety rank and high score for Price Stability.

Frederick L. Harris, III *August 22, 2025*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Nov. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	100

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 79.00 | P/E RATIO 20.4 (Trailing: 29.5 Median: 21.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$54-$94	$74 (-5%)

2028-30 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+35%)	*10%*
Low	75	(-5%)	*2%*

Institutional Decisions

	3Q2024	4Q2024	1Q2025
to Buy	144	163	181
to Sell	138	132	132
Hld's(000)	73232	74695	64309

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
High:	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	80.3	79.8						
Low:	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6	64.7						

LEGENDS
32.5 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2028 2029 2030

% TOT. RETURN 8/11/25

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.3	9.2
3 yr.	16.8	33.9
5 yr.	29.7	91.1

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Revenues per sh	*76.65*
"Cash Flow" per sh	*13.00*
Earnings per sh A	*5.00*
Div'ds Decl'd per sh B■†	*3.00*
Cap'l Spending per sh	*14.50*
Book Value per sh	*58.65*
Common Shs Outst'g C	*75.00*
Avg Ann'l P/E Ratio	*18.0*
Relative P/E Ratio	*1.00*
Avg Ann'l Div'd Yield	*3.3%*
Revenues ($mill)	*5750*
Net Profit ($mill)	*375*
Income Tax Rate	*21.0%*
Net Profit Margin	*6.5%*
Long-Term Debt Ratio	*56.0%*
Common Equity Ratio	*44.0%*
Total Capital ($mill)	*10000*
Net Plant ($mill)	*10475*
Return on Total Cap'l	*4.0%*
Return on Shr. Equity	*8.5%*
Return on Com Equity	*8.5%*
Retained to Com Eq	*3.5%*
All Div'ds to Net Prof	*60%*

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	75.93	71.22	*69.85*	*73.30*
	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.98	8.27	8.87	*9.80*	*11.40*
	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	2.76	*3.20*	*4.20*
	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.46	2.48	2.48	*2.48*	*2.48*
	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	13.18	*12.50*	*13.50*
	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	45.57	46.25	51.39	*54.25*	*55.50*
	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	71.78	*73.00*	*73.00*
	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.0	25.9	*Bold figures are Value Line estimates*	
	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.61	1.44		
	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%	3.5%		
	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5434.0	5112.4	*5100*	*5350*						
	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	198.8	*235*	*305*						
	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	- -	21.2%	15.1%	*21.0%*	*21.0%*						
	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	3.9%	*4.6%*	*5.7%*						
	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	59.0%	58.2%	54.1%	*55.0%*	*55.0%*						
	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	41.0%	41.8%	45.9%	*45.0%*	*45.0%*						
	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7462.1	7919.9	8037.4	*8800*	*9000*						
	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	8109.1	*8700*	*9290*						
	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.4%	NMF	3.8%	2.5%	*2.5%*	*3.5%*						
	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	*5.5%*	*6.0%*	*7.5%*						
	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	5.4%	*6.0%*	*7.5%*						
	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	.5%	*1.5%*	*3.0%*						
	54%	55%	53%	55%	54%	54%	69%	NMF	116%	90%	*78%*	*59%*						

CAPITAL STRUCTURE as of 6/30/25
Total Debt $4685.0 mill. **Due in 5 Yrs** $1943 mill.
LT Debt $4396.9 mill. **LT Interest** $300 mill. (52% of Cap'l)

Leases, Uncapitalized Annual rentals $23.7 mill.
Pension Assets-12/24 $1158.0 mill. **Oblig.** $1280.5 mill.

Pfd Stock None

Common Stock 71,979,296 shs. **as of 7/25/25**

MARKET CAP: $5.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	6/30/25
Cash Assets	106.5	363.8	355.6
Other	1774.6	1100.7	1069.5
Current Assets	1881.1	1464.5	1425.1
Accts Payable	346.9	331.8	254.6
Debt Due	671.1	710.0	288.1
Other	666.8	790.3	871.8
Current Liab.	1684.8	1832.1	1414.5
Fix. Chg. Cov.	145%	310%	365%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '28-'30
Revenues	5.5%	6.5%	*6.0%*
"Cash Flow"	-3.0%	-7.0%	*8.5%*
Earnings	- -	- -	*10.0%*
Dividends	6.5%	3.5%	*5.5%*
Book Value	4.5%	2.0%	*7.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	1387.6	5434.0
2024	1581.0	1182.2	1079.2	1307.6	5112.4
2025	1296.5	1120.4	*1225*	*1458.1*	*5100*
2026	*1365*	*1175*	*1285*	*1525*	*5350*

Calendar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	1.02	2.13
2024	1.22	.25	- -	1.28	2.76
2025	1.58	d.18	*.15*	*1.65*	*3.20*
2026	*1.80*	*.25*	*.15*	*2.00*	*4.20*

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62	.62	.62	.62	2.48
2025	.62	.62			

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Centuri Group spun-off in IPO 4/22/24. Southwest Gas is a regulated gas distributor serving 2.3 million customers in Arizona, Nevada, and California. 2024 revenue mix: residential 68%; small commercial, 20%; large commercial and industrial, 5%; transportation, 7%. Southwest has 2,435 employees as of 12/31/24; Centuri has 8,687. Off. & dir. own .5% of common stock; Carl C. Icahn, 13.4%; BlackRock, 12.9%; The Vanguard Group, 10.1%; Corvex Management, 6.6% (3/25 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holding's second quarter results reflect steady utility growth. Despite the company's bottom-line setback, operating performance was fairly strong. The operating margin expanded nicely, to 20% from 15% last year, adding $27 million to operating income, driven largely by rate relief across its jurisdictions and modest customer growth. Broader economic strength across Southwest's service territories contributed to demand growth, reflected in 40,000 new meter sets over the past year. However, higher labor, contractor costs, depreciation, and interest expense tied to infrastructure investments offset some of these gains. Too, a significant tax bill pushed the bottom-line into the red, although the adjusted figure was closer to our call.

The remainder of the year should follow a similar trajectory. We don't see a catalyst for earnings growth through rate case resolutions this year, but the company should continue to benefit from steady markets, past investments, and other ongoing corporate actions. Namely, the separation of Centuri is progressing nicely, with Southwest having reduced its stake to 52%, which has helped to further strengthen the balance sheet. Progress on rate cases, and the implementation of alternative ratemaking structures should reduce regulatory lag and improve cost recovery in the years ahead.

Southwest Gas is positioning as a streamlined pure-play regulated gas utility. The long-term demand outlook remains favorable due to continued population and industrial growth in the Southwest U.S., and there is emerging upside from power-hungry applications like AI-driven data centers and supercomputing. In addition to its base capital plan, Southwest has also announced a proposed $1.2 billion to $1.6 billion Great Basin expansion that could materially increase the rate base if executed. This move is driven by demand from large-load users that typically provide long-term stable demand.

Despite the company's solid business prospects, the stock has limited three- to five-year price upside potential. With much of Southwest's corporate shakeup now in the rearview, the utility's stock looks slightly too expensive.

Earl B. Humes *August 22, 2025*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early November. **(B)** Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions. **(D)** Totals may not sum due to rounding. **(E)** Rank suspended 11/17/2023 for spin-off of the Centuri Group.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	5

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UGI Utilities, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seven Natural Gas Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.10%
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.39%
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.49%
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group (3)	0.07%
5.	Adjusted Bond Yield	5.56%
6.	Equity Risk Premium (4)	4.85% - 5.24%
7.	Risk Premium Derived Common Equity Cost Rate	10.41% - 10.80%

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 7 and 8 of this Schedule).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.39% from page 2 of this Schedule.

(3) Adjustment to reflect the A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 3 of this Schedule. The 0.07% upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 0.20% = 0.07%) as derived from page 2 of this Schedule.

(4) From page 5 of this Schedule.

UGI Utilities, Inc.
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Oct-2025	5.22 %	5.56 %	5.77 %
Sep-2025	5.21	5.61	5.81
Aug-2025	5.35	5.77	5.98
Average	5.26 %	5.65 %	5.85 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.39 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.20 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

UGI Utilities, Inc.
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Seven Natural Gas Companies

	Moody's Long-Term Issuer Rating October 2025		Standard & Poor's Long-Term Issuer Rating October 2025	
Proxy Group of Seven Natural Gas Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A2	6.0	A-	7.0
Chesapeake Utilities Corporation	NR	- -	NR	- -
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Southwest Gas Holdings, Inc.	Baa1	8.0	BBB+	8.0
Average	A3	7.0	A-	7.0
UGI Utilities, Inc.	A3	7.0	NR	- -

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 4 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

UGI Utilities, Inc.
Judgment of Equity Risk Premium for the
Proxy Group of Seven Natural Gas Companies

Line No.		Proxy Group of Seven Natural Gas Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	4.77% - 5.94%
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.95%
3.	Predicted Equity Risk Premium Based on Regression Analysis of 852 Fully-Litigated Natural Gas Cases (3)	4.84%
4.	Average equity risk premium	4.85% - 5.24%

Notes: (1) From page 6 of this Schedule.
(2) From page 9 of this Schedule.
(3) From page 10 of this Schedule.

UGI Utilities, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seven Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seven Natural Gas Companies
1.	Kroll Equity Risk Premium (1)	6.10%
2.	Regression on Kroll Risk Premium Data (2)	7.13%
3.	Kroll Equity Risk Premium based on PRPM (3)	7.48%
4	Equity Risk Premium Based on Value Line Summary and Index (4)	5.81%
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	12.57%
6.	Conclusion of Equity Risk Premium	7.82%
7.	Adjusted Beta	0.61 (6) 0.76 (7)
8.	Forecasted Equity Risk Premium	4.77% - 5.94%

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2024.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2024 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.10% (from page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through October 2025.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.10% (from page 1 of this Schedule) from the projected 3-5 year total annual market return of 10.91% (described fully in note 1 on page 3 of Schedule DWD-6).

(5) Using data from Bloomberg Professional Services, Value Line, and S&P Global Market Intelligence for the S&P 500, an expected total return of 17.67% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.10% results in an expected equity risk premium of 12.57%.

(6) Average of mean and median beta from page 1 of Schedule DWD-6.

(7) Average of mean and median beta from page 2 of Schedule DWD-6.

Sources of Information:

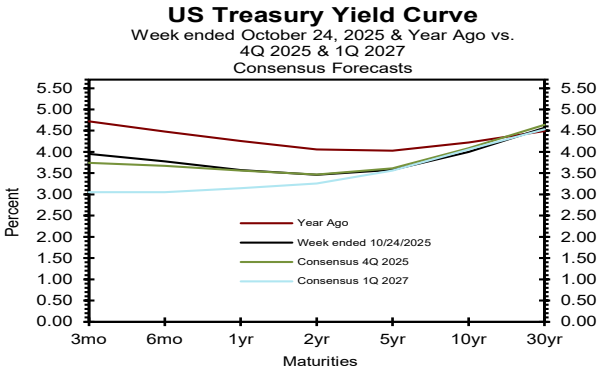
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, June 2, 2025 and October 31, 2025
S&P Capital IQ
Bloomberg Professional Services

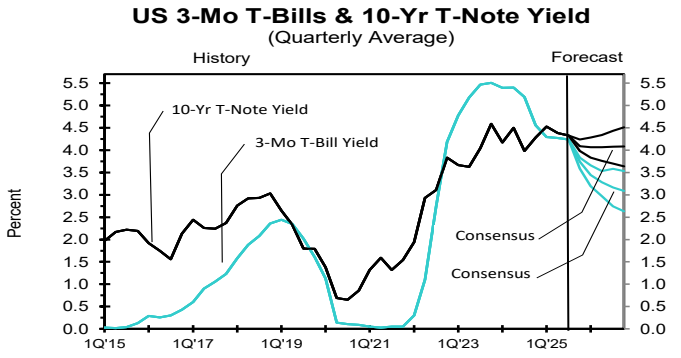
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

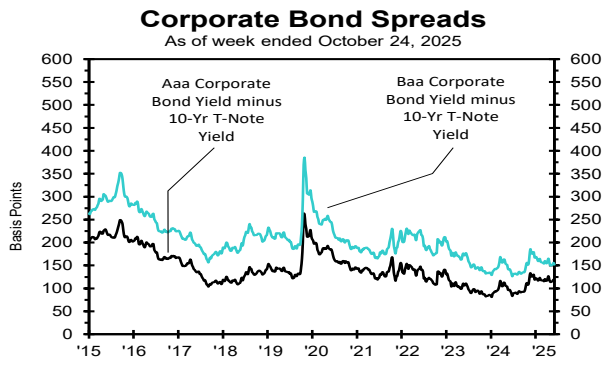
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Oct 24	Oct 17	Oct 10	Oct 3	Sep	Aug	July	3Q 2025	2025	2026	2026	2026	2026	2027
Federal Funds Rate	4.11	4.10	4.09	4.09	4.22	4.33	4.33	4.29	**3.8**	**3.5**	**3.3**	**3.2**	**3.1**	**3.0**
Prime Rate	7.25	7.25	7.25	7.25	7.38	7.50	7.50	7.46	**7.0**	**6.7**	**6.5**	**6.3**	**6.2**	**6.2**
SOFR	4.22	4.22	4.14	4.19	4.30	4.34	4.34	4.33	**3.9**	**3.5**	**3.4**	**3.3**	**3.1**	**3.1**
Commercial Paper, 1-mo.	4.00	4.03	4.04	4.05	4.13	4.28	4.30	4.24	**3.8**	**3.5**	**3.3**	**3.2**	**3.1**	**3.1**
Treasury bill, 3-mo.	3.95	4.02	4.02	4.02	4.07	4.30	4.41	4.26	**3.7**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**
Treasury bill, 6-mo.	3.78	3.80	3.82	3.82	3.84	4.11	4.31	4.09	**3.7**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**
Treasury bill, 1 yr.	3.57	3.57	3.65	3.64	3.66	3.89	4.08	3.88	**3.6**	**3.4**	**3.3**	**3.2**	**3.2**	**3.1**
Treasury note, 2 yr.	3.46	3.46	3.57	3.58	3.57	3.70	3.88	3.72	**3.5**	**3.4**	**3.3**	**3.3**	**3.3**	**3.3**
Treasury note, 5 yr.	3.58	3.59	3.71	3.71	3.66	3.79	3.95	3.80	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**
Treasury note, 10 yr.	4.00	4.02	4.13	4.13	4.12	4.26	4.39	4.26	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**
Treasury note, 30 yr.	4.57	4.61	4.71	4.71	4.74	4.87	4.92	4.84	**4.6**	**4.6**	**4.6**	**4.6**	**4.6**	**4.5**
Corporate Aaa bond	5.15	5.21	5.29	5.28	5.30	5.45	5.56	5.44	**5.1**	**5.1**	**5.1**	**5.1**	**5.1**	**5.1**
Corporate Baa bond	5.52	5.58	5.65	5.64	5.68	5.84	5.94	5.82	**5.8**	**5.8**	**5.8**	**5.9**	**5.9**	**5.9**
State & Local bonds	4.04	4.06	4.11	4.11	4.13	4.34	4.42	4.30	**4.2**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**
Home mortgage rate	6.19	6.27	6.30	6.34	6.35	6.59	6.72	6.55	**6.3**	**6.2**	**6.2**	**6.1**	**6.1**	**6.1**
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2023	2024	2024	2024	2024	2025	2025	2025*	2025	2026	2026	2026	2026	2027
Fed's AFE $ Index	116.6	115.5	117.3	114.9	117.9	119.8	112.9	111.2	**111.4**	**111.6**	**111.8**	**111.3**	**110.8**	**110.5**
Real GDP	3.4	0.8	3.6	3.3	1.9	-0.6	3.8	1.0	**1.0**	**1.5**	**1.9**	**2.0**	**2.0**	**2.0**
GDP Price Index	1.6	3.1	2.6	1.8	2.4	3.6	2.1	3.1	**2.9**	**2.6**	**2.4**	**2.3**	**2.3**	**2.3**
Consumer Price Index	2.8	3.7	2.8	1.4	3.0	3.8	1.6	3.1a	**3.4**	**3.0**	**2.5**	**2.4**	**2.5**	**2.4**
PCE Price Index	1.8	3.6	2.6	1.7	2.5	3.4	2.1	3.3	**3.2**	**2.8**	**2.5**	**2.4**	**2.3**	**2.3**

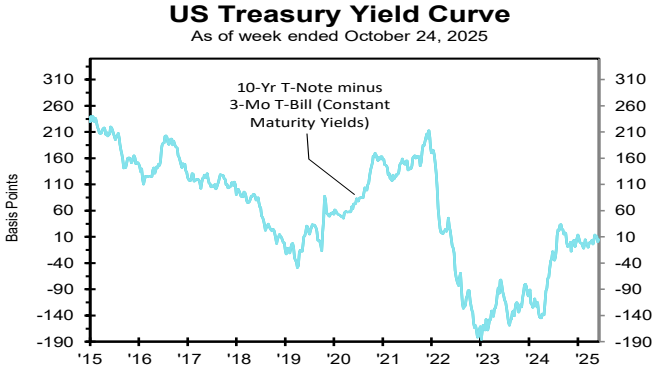
a=actual

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Figures for 3Q 2025 Real GDP, GDP Chained Price Index and PCE Price Index are consensus forecasts from the September 2025 survey.









Long-Range Survey:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2026 through 2031 and averages for the five-year periods 2027-2031 and 2032-2036. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
1. Federal Funds Rate	**CONSENSUS**	**3.4**	**3.2**	**3.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.7	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.0	2.9	2.9	2.8	2.9	2.9	2.8
2. Prime Rate	**CONSENSUS**	**6.5**	**6.4**	**6.3**	**6.3**	**6.2**	**6.2**	**6.3**	**6.2**
	Top 10 Average	6.7	6.6	6.5	6.6	6.5	6.5	6.5	6.5
	Bottom 10 Average	6.2	6.2	6.0	6.0	5.9	5.9	6.0	5.9
3. SOFR	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.3	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.2	3.2	3.0	2.9	2.9	2.9	3.0	2.8
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.5	3.4	3.3	3.2	3.2	3.2	3.3	3.3
	Bottom 10 Average	3.3	3.3	3.1	3.0	3.0	3.0	3.1	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.4	3.3	3.3	3.4	3.3
	Bottom 10 Average	3.1	2.9	2.9	2.8	2.8	2.8	2.9	2.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.9	2.9	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	3.6	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.1	3.1	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.4**	**3.4**	**3.5**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
	Top 10 Average	3.7	3.6	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.1
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0
	Bottom 10 Average	3.4	3.5	3.5	3.5	3.4	3.4	3.5	3.4
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
	Top 10 Average	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	Bottom 10 Average	3.8	3.9	3.8	3.8	3.8	3.8	3.8	3.8
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.3**	**4.4**	**4.3**
	Top 10 Average	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.7
	Bottom 10 Average	4.2	4.3	4.1	4.1	4.1	4.1	4.1	4.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.2**	**5.2**	**5.1**	**5.1**	**5.1**	**5.1**	**5.1**
	Top 10 Average	5.4	5.5	5.4	5.4	5.4	5.4	5.4	5.4
	Bottom 10 Average	5.0	5.0	4.9	4.9	4.9	4.9	4.9	4.9
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.8	5.9	5.8	5.8	5.8	5.7	5.8	5.8
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.3**	**4.2**	**4.2**	**4.2**	**4.3**	**4.1**
	Top 10 Average	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4
	Bottom 10 Average	4.1	4.2	4.1	4.1	4.1	4.1	4.1	3.8
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.2**	**6.1**	**6.0**	**6.0**	**6.0**	**6.1**	**5.9**
	Top 10 Average	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.9	6.0	5.8	5.8	5.8	5.7	5.8	5.6
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**113.3**	**112.7**	**112.7**	**112.2**	**111.7**	**111.3**	**112.1**	**110.8**
	Top 10 Average	114.2	113.3	113.4	112.9	112.5	112.2	112.8	112.4
	Bottom 10 Average	112.2	111.9	112.0	111.3	110.7	110.3	111.3	109.1
		Year-Over-Year, % Change						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
B. Real GDP	**CONSENSUS**	**1.5**	**1.9**	**2.0**	**2.0**	**1.9**	**2.0**	**2.0**	**1.9**
	Top 10 Average	1.9	2.1	2.2	2.2	2.2	2.2	2.2	2.1
	Bottom 10 Average	1.1	1.8	1.8	1.8	1.7	1.7	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.6	2.3	2.2	2.2	2.2	2.2	2.2	2.2
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.5**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.9	2.4	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.1
E. PCE Price Index	**CONSENSUS**	**2.4**	**2.0**	**2.0**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**
	Top 10 Average	2.8	2.3	2.2	2.1	2.1	2.1	2.2	2.1
	Bottom 10 Average	2.1	1.8	1.8	1.8	1.7	1.8	1.8	1.8

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
1.	Historical Equity Risk Premium (1)	4.16%
2.	Regression of Historical Equity Risk Premium (2)	5.00%
3	Forecasted Equity Risk Premium Based on PRPM (3)	4.22%
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	6.40%
5.	Average Equity Risk Premium (5)	4.95%

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2024. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

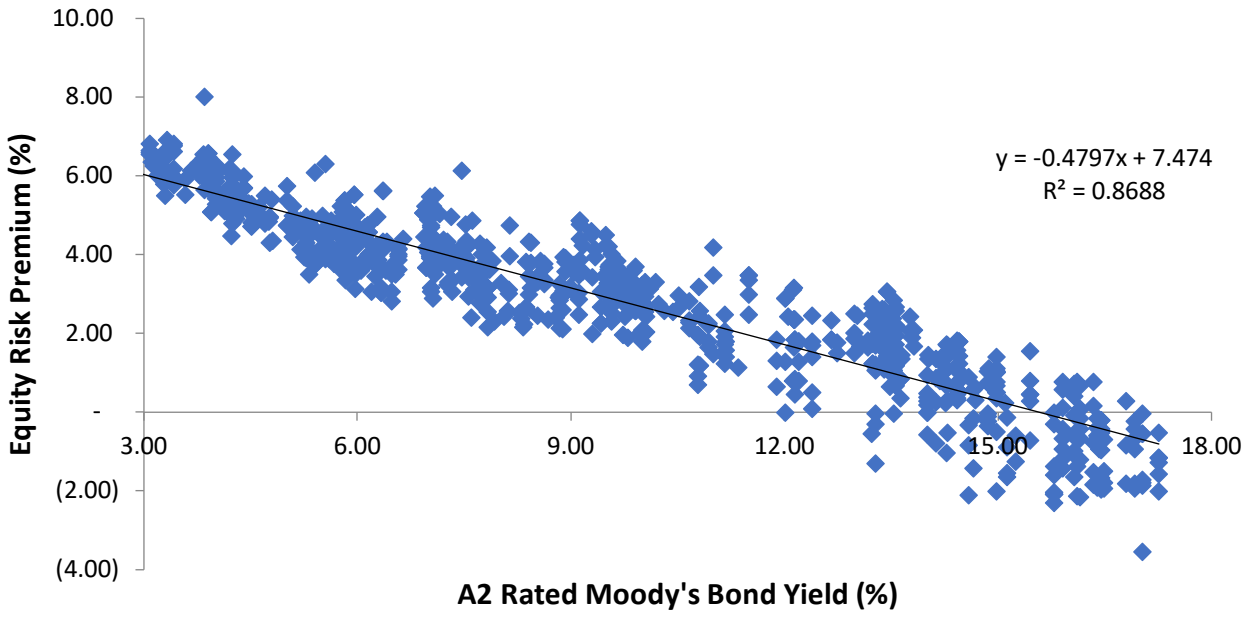
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2024 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.49% (from line 3, page 1 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - October 2025.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 11.89% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.49%, calculated on line 3 of page 1 of this Schedule results in an equity risk premium of 6.40% (11.89% - 5.49% = 6.40%).

(5) Average of lines 1 through 4.

UGI Utilities, Inc.
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Gas Utilities



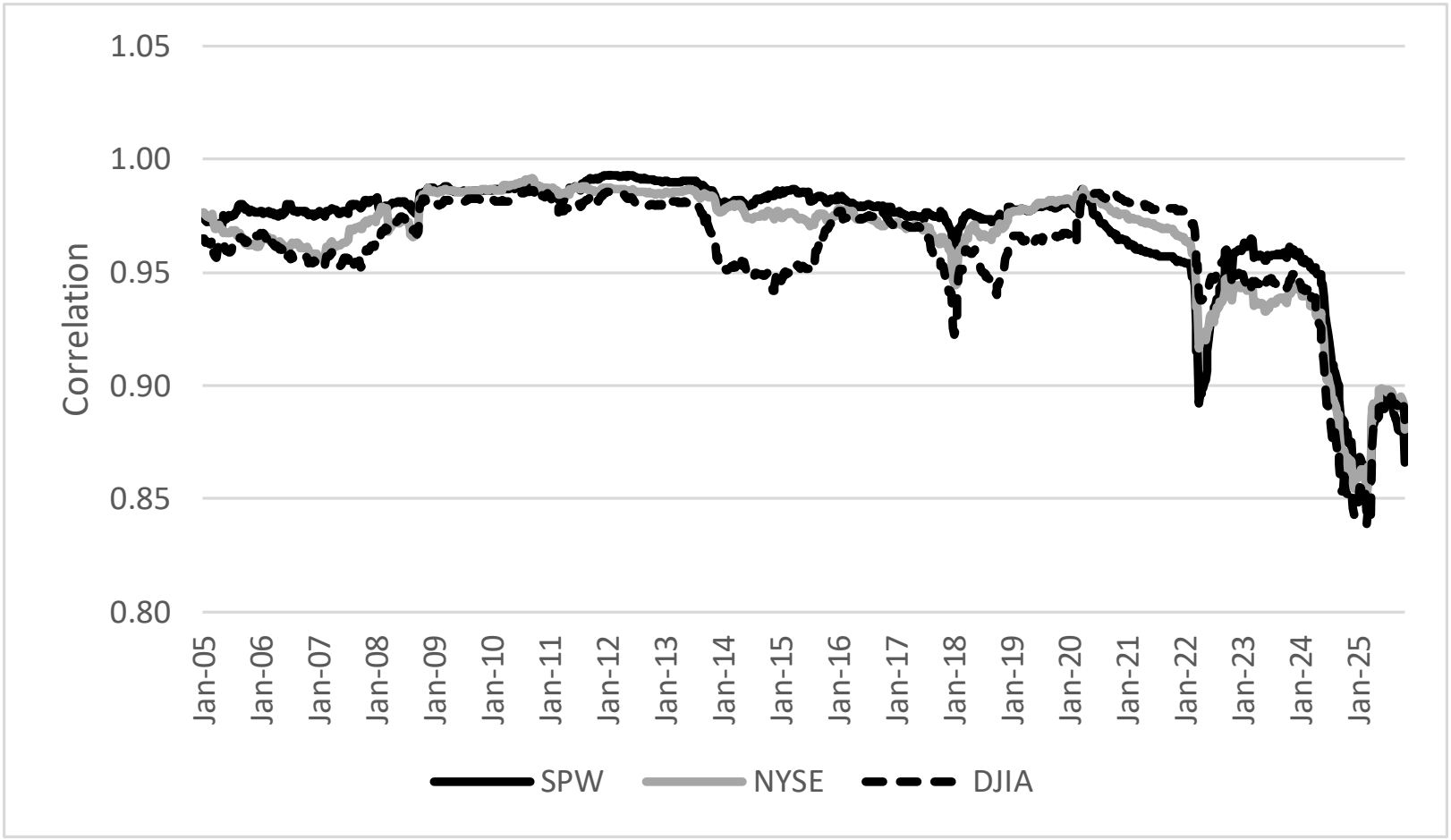
Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.4740 %	-0.4797	5.49 %	4.84 %

Notes:

(1) From line 3 of page 1 of this Schedule.

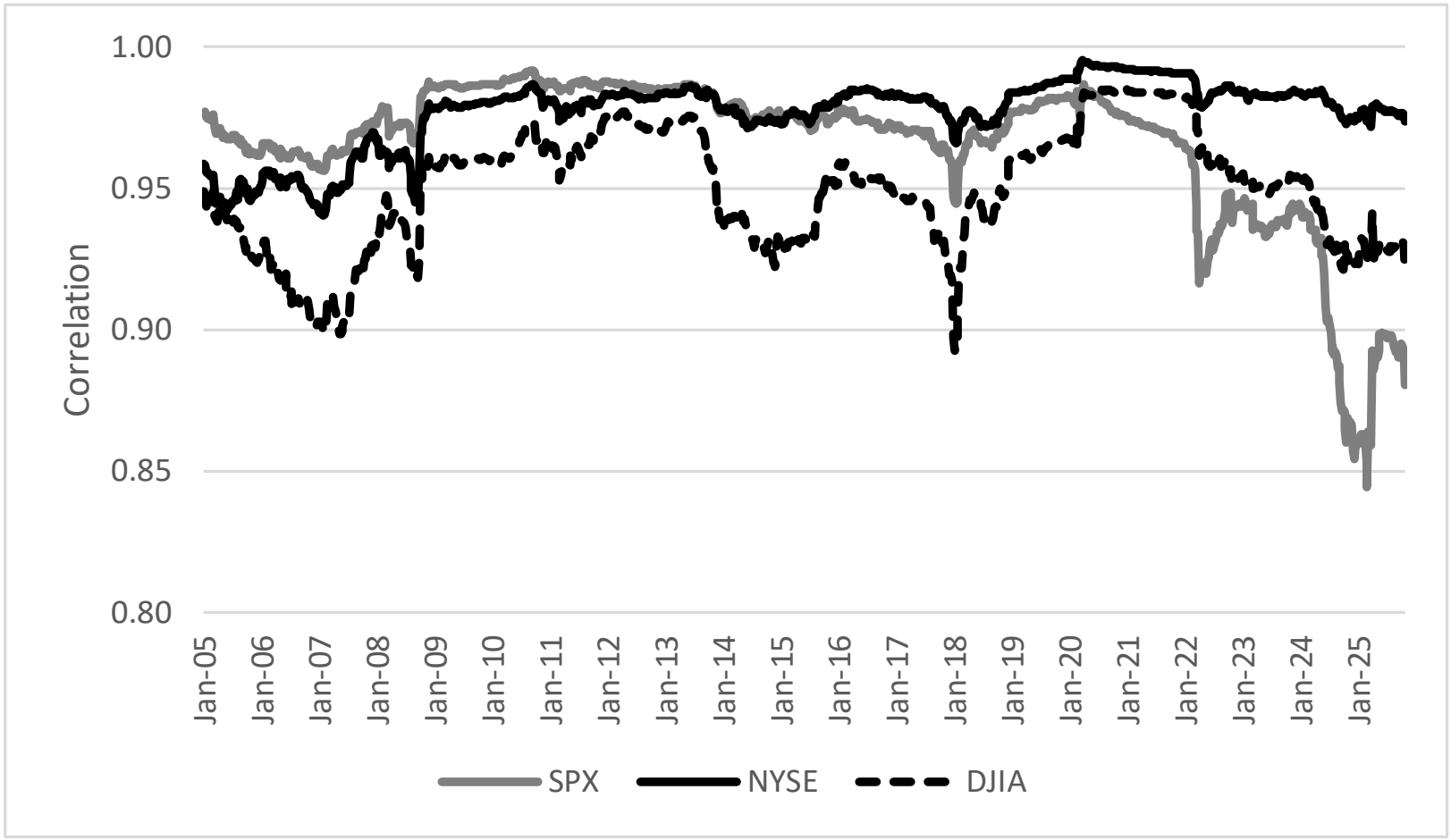
Source of Information: Regulatory Research Associates.

UGI Utilities, Inc.
S&P 500 Correlations



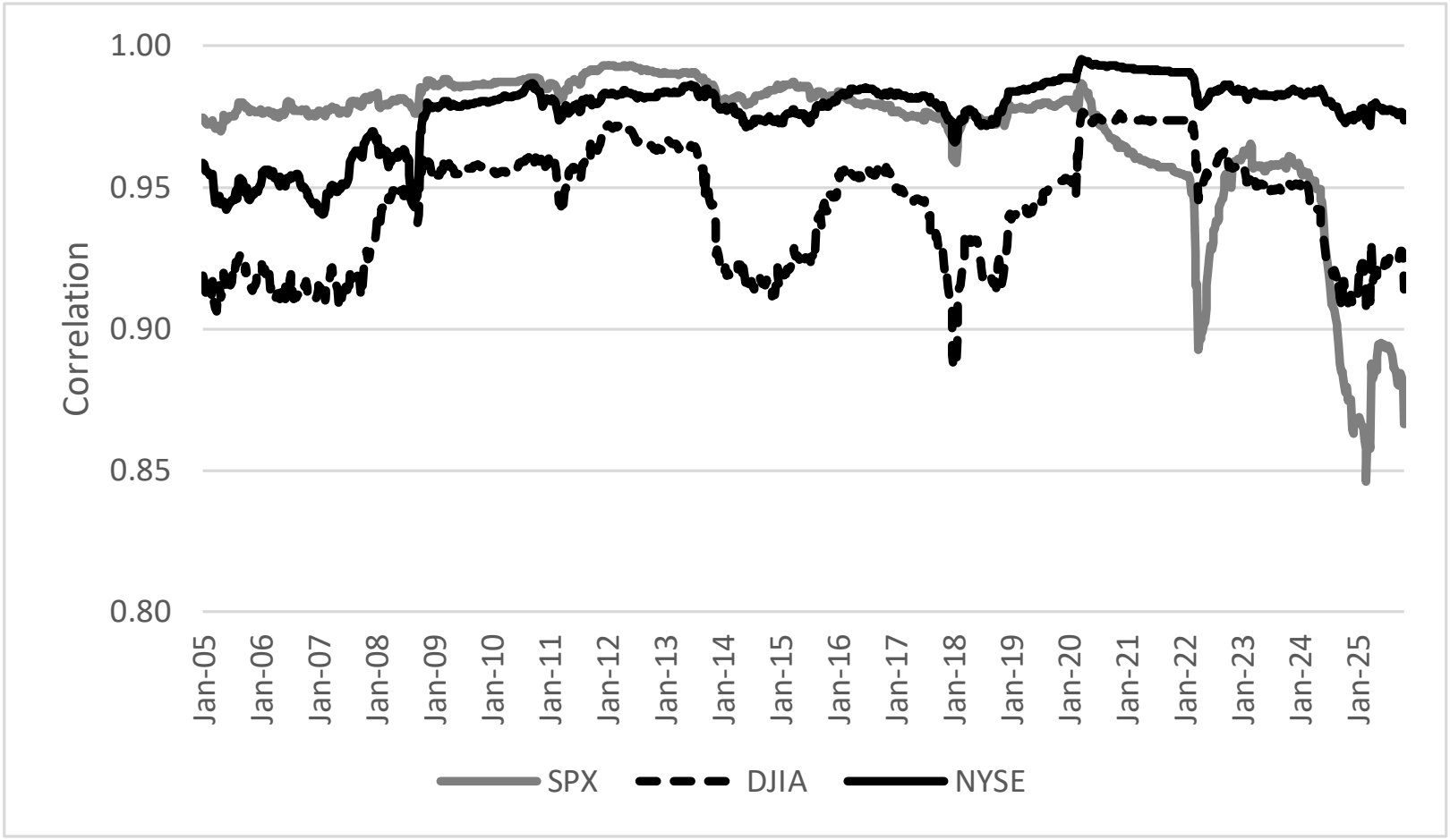
Source: Bloomberg Professional

UGI Utilities, Inc.
NYSE Correlations



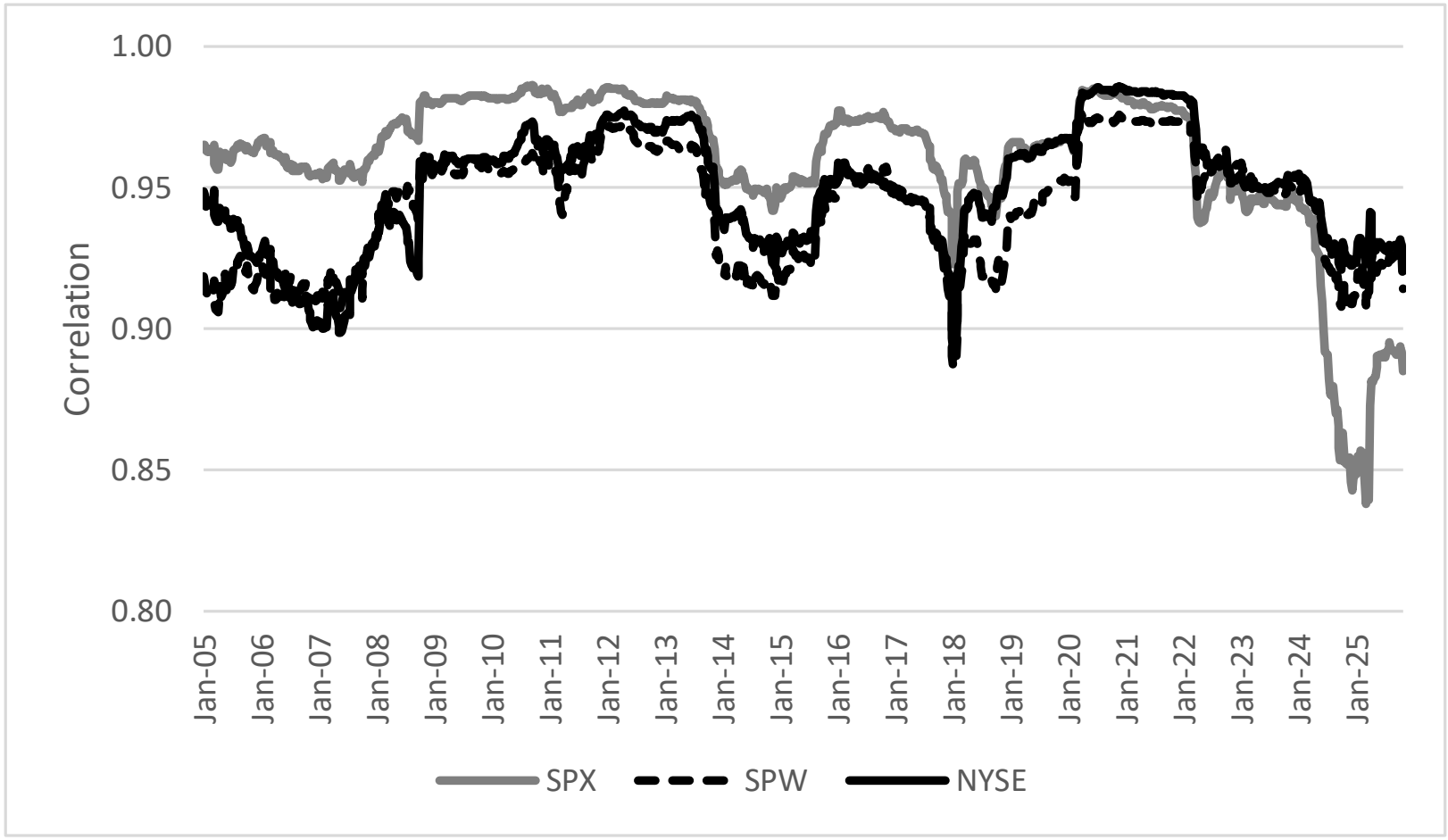
Source: Bloomberg Professional

UGI Utilities, Inc.
SPW Correlations



Source: Bloomberg Professional

UGI Utilities, Inc.
DJIA Correlations



Source: Bloomberg Professional

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Seven Natural Gas Companies

Proxy Group of Seven Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.75	0.43	0.59	8.63 %	4.53 %	9.62 %	10.50 %	10.06 %
Chesapeake Utilities Corporation	0.70	0.39	0.54	8.63	4.53	9.19	10.18	9.68
New Jersey Resources Corporation	0.80	0.42	0.61	8.63	4.53	9.79	10.63	10.21
NiSource Inc.	0.80	0.54	0.67	8.63	4.53	10.31	11.02	10.67
Northwest Natural Holding Company	0.75	0.45	0.60	8.63	4.53	9.71	10.57	10.14
ONE Gas, Inc.	0.75	0.43	0.59	8.63	4.53	9.62	10.50	10.06
Southwest Gas Holdings, Inc.	0.75	0.57	0.66	8.63	4.53	10.22	10.96	10.59
Mean			0.61			9.78 %	10.62 %	10.20 %
Median			0.60			9.71 %	10.57 %	10.14 %
Average of Mean and Median			0.61			9.75 %	10.60 %	10.17 %

Notes on page 3 of this Schedule.

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Seven Natural Gas Companies

	[1]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Companies	Value Line Adjusted Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.75	8.63 %	4.53 %	11.00 %	11.54 %	11.27 %
Chesapeake Utilities Corporation	0.70	8.63	4.53	10.57	11.22	10.89
New Jersey Resources Corporation	0.80	8.63	4.53	11.43	11.86	11.65
NiSource Inc.	0.80	8.63	4.53	11.43	11.86	11.65
Northwest Natural Holding Company	0.75	8.63	4.53	11.00	11.54	11.27
ONE Gas, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Southwest Gas Holdings, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Mean	0.76			11.06 %	11.59 %	11.32 %
Median	0.75			11.00 %	11.54 %	11.27 %
Average of Mean and Median	0.76			11.03 %	11.57 %	11.30 %

Notes on page 3 of this Schedule.

UGI Utilities, Inc.
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

Measure 1: Kroll Arithmetic Mean MRP (1926-2024)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2024:	12.29 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99
MRP based on Kroll Historical Data:	7.31 %

Measure 2: Application of a Regression Analysis to Kroll Historical Data

(1926-2024)	7.96 %

Measure 3: Application of the PRPM to Kroll Historical Data

(January 1926 - October 2025)	8.35 %

Measure 4: Value Line Projected MRP (Thirteen weeks ending October 31, 2025)

Total projected return on the market 3-5 years hence*:	10.91 %
Risk-Free Rate (see note 2):	4.53
MRP based on Value Line Summary & Index:	6.38 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	17.67 %
Risk-Free Rate (see note 2):	4.53
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	13.14 %

Average of all MRP Measures:	8.63 %

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 7 and 8 of Schedule DWD-4.) The projection of the risk-free rate is illustrated below:

Fourth Quarter 2025	4.60 %
First Quarter 2026	4.60
Second Quarter 2026	4.60
Third Quarter 2026	4.60
Fourth Quarter 2026	4.60
First Quarter 2027	4.50
2027-2031	4.40
2032-2036	4.30
	4.53 %

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, June 2, 2025 and October 31, 2025
Kroll 2023 SBBI® Yearbook
S&P Capital IQ
Bloomberg Professional Services

UGI Utilities, Inc.
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Seven Natural Gas Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of seven natural gas companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.43 - 0.77 and residual standard error of the regression range of 2.6407 - 3.1495 of the proxy group of seven natural gas companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1272. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1272 = \frac{2.8951}{\sqrt{518}} = \frac{2.8951}{22.7596}$$

Source of Information: Value Line Proprietary Database, September 2025.
Value Line Investment Survey (Standard Edition).

UGI Utilities, Inc.
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Seven Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.75	0.57	2.4158	0.0691
Chesapeake Utilities Corporation	0.70	0.52	3.0212	0.0864
New Jersey Resources Corporation	0.80	0.65	2.8619	0.0819
NiSource Inc.	0.80	0.69	2.5116	0.0719
Northwest Natural Holding Company	0.75	0.59	3.0386	0.0869
ONE Gas, Inc.	0.75	0.58	3.1364	0.0897
Southwest Gas Holdings, Inc.	0.75	0.61	3.2803	0.0939
Average	0.76	0.60	2.8951	0.0828
Beta Range (+/- 2 std. Devs. of Beta)	0.43	0.77		
2 std. Devs. of Beta	0.17			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.6407	3.1495		
Std. dev. of the Res. Std. Err.	0.1272			
2 std. devs. of the Res. Std. Err.	0.2544			

Source of Information: Value Line Proprietary Database, September 2025.

UGI Utilities, Inc.
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Thirty-Two Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
AbbVie Inc.	0.70	0.49	2.9870	0.0855
Altria Group, Inc.	0.70	0.48	2.6441	0.0757
Amgen Inc.	0.70	0.51	2.8876	0.0826
AutoZone, Inc.	0.75	0.60	2.9668	0.0849
Becton, Dickinson and Company	0.75	0.56	2.8111	0.0804
Bristol-Myers Squibb Company	0.70	0.51	3.0539	0.0874
Casella Waste Systems, Inc.	0.85	0.72	2.8452	0.0814
Cencora Inc.	0.65	0.46	2.6732	0.0765
Chemed Corporation	0.70	0.47	3.0295	0.0867
Constellation Brands, Inc.	0.75	0.62	2.9738	0.0851
Costco Wholesale Corporation	0.80	0.65	2.7892	0.0798
Gilead Sciences, Inc.	0.75	0.57	2.9548	0.0845
Jack Henry & Associates, Inc.	0.80	0.69	2.6933	0.0771
International Business Machines Corporation	0.80	0.67	3.0115	0.0862
L3Harris Technologies, Inc.	0.80	0.67	3.0192	0.0864
Labcorp Holdings Inc.	0.75	0.62	2.8431	0.0813
McCormick & Company, Incorporated	0.70	0.48	2.9988	0.0858
McKesson Corporation	0.70	0.50	2.8220	0.0807
Merck & Co., Inc.	0.65	0.45	3.0459	0.0871
Monster Beverage Corporation	0.70	0.51	2.7151	0.0777
NewMarket Corporation	0.75	0.60	2.8794	0.0824
O'Reilly Automotive, Inc.	0.75	0.61	2.7765	0.0794
Philip Morris International Inc.	0.75	0.61	2.9157	0.0834
The Progressive Corporation	0.75	0.62	2.9673	0.0849
Restaurant Brands International Inc.	0.85	0.77	2.6916	0.0770
RLI Corp.	0.85	0.73	2.7590	0.0789
Rollins, Inc.	0.80	0.65	3.1399	0.0898
Henry Schein, Inc.	0.80	0.67	3.0644	0.0877
Service Corporation International	0.85	0.73	3.0032	0.0859
Verisk Analytics, Inc.	0.85	0.74	2.6834	0.0768
Walmart Inc.	0.75	0.57	2.7118	0.0776
The Wendy's Company	0.80	0.69	3.0367	0.0869
Average	0.76	0.60	2.8873	0.0826
Proxy Group of Seven Natural Gas Companies	0.76	0.60	2.8951	0.0828

Source of Information: Value Line Proprietary Database, September 2025.

UGI Utilities, Inc.
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Principal Methods	Proxy Group of Thirty-Two Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	11.29%
Risk Premium Model (RPM) (2)	10.94% - 11.64%
Capital Asset Pricing Model (CAPM) (3)	10.68% - 11.29%
Mean	10.97% - 11.41%
Median	10.94% - 11.29%
Average of Mean and Median	10.96% - 11.35%

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From pages 6 and 7 of this Schedule.

UGI Utilities, Inc.
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Thirty-Two Non-Price Regulated Companies	[1] Average Dividend Yield	[2] Value Line Projected Five Year Growth in EPS	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth Rate in EPS (1)	[6] Adjusted Dividend Yield	[7] Indicated Common Equity Cost Rate (2)
AbbVie Inc.	3.16 %	7.00 %	15.00 %	14.47 %	12.16 %	3.35 %	15.51 %
Altria Group, Inc.	6.50	6.00	3.30	3.62	4.31	6.64	10.95
Amgen Inc.	3.30	5.50	5.30	5.09	5.30	3.39	8.69
AutoZone, Inc.	-	7.50	13.80	12.42	11.24	-	NA
Becton, Dickinson and Company	2.19	7.00	8.60	7.29	7.63	2.27	9.90
Bristol-Myers Squibb Company	5.42	27.50	3.00	NMF	15.25	5.83	21.08 (3)
Casella Waste Systems, Inc.	-	6.50	NA	(6.88)	6.50	-	NA
Cencora Inc.	0.72	6.50	12.30	11.47	10.09	0.76	10.85
Chemed Corporation	0.54	6.50	8.80	8.76	8.02	0.56	8.58
Constellation Brands, Inc.	2.79	3.50	28.90	(2.49)	16.20	3.02	19.22
Costco Wholesale Corporation	0.55	11.50	8.30	8.68	9.49	0.58	10.07
Gilead Sciences, Inc.	2.72	16.00	18.10	22.18	18.76	2.98	21.74 (3)
Jack Henry & Associates, Inc.	1.49	9.00	9.00	NA	9.00	1.56	10.56
International Business Machines Corporation	2.51	3.00	6.30	6.81	5.37	2.58	7.95
L3Harris Technologies, Inc.	1.69	14.50	13.00	13.02	13.51	1.80	15.31
Labcorp Holdings Inc.	1.04	6.50	9.30	9.18	8.33	1.08	9.41
McCormick & Company, Incorporated	2.65	6.00	5.70	4.99	5.56	2.72	8.28
McKesson Corporation	0.45	12.00	14.60	14.62	13.74	0.48	14.22
Merck & Co., Inc.	3.84	13.00	10.20	8.23	10.48	4.04	14.52
Monster Beverage Corporation	-	12.00	15.10	15.12	14.07	-	NA
NewMarket Corporation	1.50	6.00	NA	NA	6.00	1.55	7.55
O'Reilly Automotive, Inc.	-	10.50	12.80	14.18	12.49	-	NA
Philip Morris International Inc.	3.64	5.00	9.20	11.24	8.48	3.79	12.27
The Progressive Corporation	0.17	16.50	9.80	13.51	13.27	0.18	13.45
Restaurant Brands International Inc.	3.80	12.50	8.90	6.39	9.26	3.98	13.24
RLI Corp.	0.99	13.50	NA	NA	13.50	1.06	14.56
Rollins, Inc.	1.28	9.50	NA	NA	9.50	1.34	10.84
Henry Schein, Inc.	-	10.50	6.30	6.96	7.92	-	NA
Service Corporation International	1.58	7.50	10.80	10.77	9.69	1.66	11.35
Verisk Analytics, Inc.	0.72	11.00	10.90	9.20	10.37	0.76	11.13
Walmart Inc.	0.92	10.00	8.20	7.81	8.67	0.96	9.63
The Wendy's Company	5.84	11.00	6.10	2.99	6.70	6.04	12.74
	NA = Not Available					Mean	11.63 %
	NMF=Not Meaningful Figure					Median	10.95 %
						Average of Mean and Median	11.29 %

Notes:

(1) Average of columns 2 through 4 excluding negative growth rates and extreme positive values.

(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 10/31/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:

Value Line Investment Survey.
www.zacks.com, Downloaded on 10/31/2025
S&P Capital IQ

UGI Utilities, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Thirty-Two Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	5.89%
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	-0.19%
3.	Adjusted Bond Yield	5.70%
4.	Equity Risk Premium (3)	5.24% - 5.94%
5.	Risk Premium Derived Common Equity Cost Rate	10.94% - 11.64%

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated June 2, 2025 and October 31, 2025 (see pages 7 and 8 of Schedule DWD-4). The estimates are detailed below.

Fourth Quarter 2025	5.80 %
First Quarter 2026	5.80
Second Quarter 2026	5.80
Third Quarter 2026	5.90
Fourth Quarter 2026	5.90
First Quarter 2027	5.90
2027-2031	6.00
2032-2036	6.00
Average	5.89 %

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending October 2025. To reflect the A3 average rating of the Non-Price Regulated Proxy Group, the yield on the Baa corporate bond must be adjusted by 2/3 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Oct-25	5.52 %	5.80 %	0.28 %
Sep-25	5.55	5.83	0.28
Aug-25	5.72	6.00	0.28
		Average yield spread	0.28 %
		2/3 of spread	0.19 %

(3) From page 5 of this Schedule.

UGI Utilities, Inc.
Comparison of Long-Term Issuer Ratings for the
and Proxy Group of Thirty-Two Non-Price Regulated Companies

Proxy Group of Thirty-Two Non-Price Regulated Companies	Moody's Long-Term Issuer Rating October 2025		Standard & Poor's Long-Term Issuer Rating October 2025	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
AbbVie Inc.	A3	7.0	A-	7.0
Altria Group, Inc.	A3	7.0	BBB+	8.0
Amgen Inc.	Baa1	8.0	BBB+	8.0
AutoZone, Inc.	Baa1	8.0	BBB	9.0
Becton, Dickinson and Company	Baa2	9.0	BBB	9.0
Bristol-Myers Squibb Company	A2	6.0	A	6.0
Casella Waste Systems, Inc.	NA	--	BB	12.0
Cencora Inc.	Baa1	8.0	BBB+	8.0
Chemed Corporation	WR	--	NR	--
Constellation Brands, Inc.	Baa2	9.0	BBB	9.0
Costco Wholesale Corporation	Aa3	4.0	AA	3.0
Gilead Sciences, Inc.	A3	7.0	A-	7.0
Jack Henry & Associates, Inc.	NA	--	NA	--
International Business Machines Corporation	A3	7.0	A-	7.0
L3Harris Technologies, Inc.	Baa2	9.0	BBB	9.0
Labcorp Holdings Inc.	NA	--	BBB	9.0
McCormick & Company, Incorporated	Baa2	9.0	BBB	9.0
McKesson Corporation	A3	7.0	BBB+	8.0
Merck & Co., Inc.	Aa3	4.0	A+	5.0
Monster Beverage Corporation	NA	--	NA	--
NewMarket Corporation	Baa2	9.0	BBB+	8.0
O'Reilly Automotive, Inc.	Baa1	8.0	BBB	9.0
Philip Morris International Inc.	A2	6.0	A-	7.0
The Progressive Corporation	A2	6.0	A	6.0
Restaurant Brands International Inc.	NA	--	BB	12.0
RLI Corp.	WR	--	BBB	9.0
Rollins, Inc.	NA	--	BBB	9.0
Henry Schein, Inc.	NA	--	NA	--
Service Corporation International	Ba3	13.0	BB+	11.0
Verisk Analytics, Inc.	Baa1	8.0	BBB	9.0
Walmart Inc.	Aa2	3.0	AA	3.0
The Wendy's Company	NA	--	B+	14.0
Proxy Group of Thirty-Two Non-Price Regulated Companies Average	A3	7.4	BBB+	8.2

Notes:
(1) From page 4 of Schedule DWD-4.

Source of Information:
Bloomberg Professional Services.

UGI Utilities, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Thirty-Two Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.10%
2.	Regression on Kroll Risk Premium Data (2)	7.13%
3.	Kroll Equity Risk Premium based on PRPM (3)	7.48%
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.81%
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	12.57%
6.	Conclusion of Equity Risk Premium	7.82%
7.	Adjusted Beta	0.67 (6) 0.76 (7)
8.	Forecasted Equity Risk Premium	5.24% - 5.94%

Notes:
(1) From note 1 of page 6 of Schedule DWD-4.
(2) From note 2 of page 6 of Schedule DWD-4.
(3) From note 3 of page 6 of Schedule DWD-4.
(4) From note 4 of page 6 of Schedule DWD-4.
(5) From note 5 of page 6 of Schedule DWD-4.
(6) Average of mean and median beta from page 6 of this Schedule.
(7) Average of mean and median beta from page 7 of this Schedule.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts, June 2, 2025 and October 31, 2025
Bloomberg Professional Services.

UGI Utilities, Inc.
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Thirty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
AbbVie Inc.	0.70	0.53	0.61	8.63 %	4.53 %	9.79 %	10.63 %	10.21 %
Altria Group, Inc.	0.70	0.31	0.51	8.63	4.53	8.93	9.99	9.46 (4)
Amgen Inc.	0.70	0.60	0.65	8.63	4.53	10.14	10.89	10.52
AutoZone, Inc.	0.75	0.52	0.64	8.63	4.53	10.05	10.83	10.44
Becton, Dickinson and Company	0.75	0.59	0.67	8.63	4.53	10.31	11.02	10.67
Bristol-Myers Squibb Company	0.70	0.46	0.58	8.63	4.53	9.53	10.44	9.99
Casella Waste Systems, Inc.	0.85	0.56	0.70	8.63	4.53	10.57	11.22	10.89
Cencora Inc.	0.65	0.39	0.52	8.63	4.53	9.02	10.05	9.53
Chemed Corporation	0.70	0.52	0.61	8.63	4.53	9.79	10.63	10.21
Constellation Brands, Inc.	0.75	0.62	0.68	8.63	4.53	10.40	11.09	10.74
Costco Wholesale Corporation	0.80	0.73	0.77	8.63	4.53	11.17	11.67	11.42
Gilead Sciences, Inc.	0.75	0.55	0.65	8.63	4.53	10.14	10.89	10.52
Jack Henry & Associates, Inc.	0.80	0.42	0.61	8.63	4.53	9.79	10.63	10.21
International Business Machines Corporation	0.80	0.77	0.78	8.63	4.53	11.26	11.73	11.50
L3Harris Technologies, Inc.	0.80	0.65	0.72	8.63	4.53	10.74	11.35	11.04
Labcorp Holdings Inc.	0.75	0.60	0.67	8.63	4.53	10.31	11.02	10.67
McCormick & Company, Incorporated	0.70	0.48	0.59	8.63	4.53	9.62	10.50	10.06
McKesson Corporation	0.70	0.52	0.61	8.63	4.53	9.79	10.63	10.21
Merck & Co., Inc.	0.65	0.68	0.67	8.63	4.53	10.31	11.02	10.67
Monster Beverage Corporation	0.70	0.53	0.61	8.63	4.53	9.79	10.63	10.21
NewMarket Corporation	0.75	0.76	0.75	8.63	4.53	11.00	11.54	11.27
O'Reilly Automotive, Inc.	0.75	0.49	0.62	8.63	4.53	9.88	10.70	10.29
Philip Morris International Inc.	0.75	0.27	0.51	8.63	4.53	8.93	9.99	9.46 (4)
The Progressive Corporation	0.75	0.67	0.71	8.63	4.53	10.66	11.28	10.97
Restaurant Brands International Inc.	0.90	0.56	0.73	8.63	4.53	10.83	11.41	11.12
RLI Corp.	0.85	0.49	0.67	8.63	4.53	10.31	11.02	10.67
Rollins, Inc.	0.80	0.65	0.73	8.63	4.53	10.83	11.41	11.12
Henry Schein, Inc.	0.80	0.64	0.72	8.63	4.53	10.74	11.35	11.04
Service Corporation International	0.85	0.64	0.75	8.63	4.53	11.00	11.54	11.27
Verisk Analytics, Inc.	0.85	0.55	0.70	8.63	4.53	10.57	11.22	10.89
Walmart Inc.	0.75	0.80	0.78	8.63	4.53	11.26	11.73	11.50
The Wendy's Company	0.80	0.62	0.71	8.63	4.53	10.66	11.28	10.97
		Mean	0.66			10.25 %	10.98 %	10.69 %
		Median	0.67			10.31 %	11.02 %	10.67 %
		Average of Mean and Median	0.67			10.28 %	11.00 %	10.68 %

Notes:
(1) From note 1 of page 3 of Schedule DWD-6.
(2) From note 2 of page 3 of Schedule DWD-6.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

UGI Utilities, Inc.
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]
Proxy Group of Thirty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
AbbVie Inc.	0.70	8.63 %	4.53 %	10.57 %	11.22 %	10.89 %
Altria Group, Inc.	0.70	8.63	4.53	10.57	11.22	10.89
Amgen Inc.	0.70	8.63	4.53	10.57	11.22	10.89
AutoZone, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Becton, Dickinson and Company	0.75	8.63	4.53	11.00	11.54	11.27
Bristol-Myers Squibb Company	0.70	8.63	4.53	10.57	11.22	10.89
Casella Waste Systems, Inc.	0.85	8.63	4.53	11.86	12.19	12.02
Cencora Inc.	0.65	8.63	4.53	10.14	10.89	10.52
Chemed Corporation	0.70	8.63	4.53	10.57	11.22	10.89
Constellation Brands, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Costco Wholesale Corporation	0.80	8.63	4.53	11.43	11.86	11.65
Gilead Sciences, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Jack Henry & Associates, Inc.	0.80	8.63	4.53	11.43	11.86	11.65
International Business Machines Corporation	0.80	8.63	4.53	11.43	11.86	11.65
L3Harris Technologies, Inc.	0.80	8.63	4.53	11.43	11.86	11.65
Labcorp Holdings Inc.	0.75	8.63	4.53	11.00	11.54	11.27
McCormick & Company, Incorporated	0.70	8.63	4.53	10.57	11.22	10.89
McKesson Corporation	0.70	8.63	4.53	10.57	11.22	10.89
Merck & Co., Inc.	0.65	8.63	4.53	10.14	10.89	10.52
Monster Beverage Corporation	0.70	8.63	4.53	10.57	11.22	10.89
NewMarket Corporation	0.75	8.63	4.53	11.00	11.54	11.27
O'Reilly Automotive, Inc.	0.75	8.63	4.53	11.00	11.54	11.27
Philip Morris International Inc.	0.75	8.63	4.53	11.00	11.54	11.27
The Progressive Corporation	0.75	8.63	4.53	11.00	11.54	11.27
Restaurant Brands International Inc.	0.90	8.63	4.53	12.29	12.51	12.40 (4)
RLI Corp.	0.85	8.63	4.53	11.86	12.19	12.02
Rollins, Inc.	0.80	8.63	4.53	11.43	11.86	11.65
Henry Schein, Inc.	0.80	8.63	4.53	11.43	11.86	11.65
Service Corporation International	0.85	8.63	4.53	11.86	12.19	12.02
Verisk Analytics, Inc.	0.85	8.63	4.53	11.86	12.19	12.02
Walmart Inc.	0.75	8.63	4.53	11.00	11.54	11.27
The Wendy's Company	0.80	8.63	4.53	11.43	11.86	11.65
Mean	0.76			11.08 %	11.60 %	11.31 %
Median	0.75			11.00 %	11.54 %	11.27 %
Average of Mean and Median	0.76			11.04 %	11.57 %	11.29 %

Notes:
(1) From note 1 of page 3 of Schedule DWD-6.
(2) From note 2 of page 3 of Schedule DWD-6.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

UGI Utilities, Inc.
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on October 31, 2025 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	UGI Utilities, Inc.	$ 4,001.105		5	0.74%	
2.	Proxy Group of Seven Natural Gas Companies	$ 4,801.525	1.2 x	5	0.74%	0.00%
			[A]	[B]	[C]	[D]

	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 47,156.530	$ 3,522,211.140	-0.01%
	2	20,191.220	46,949.060	0.33%
	3	9,937.940	20,178.360	0.49%
	4	6,196.710	9,937.350	0.50%
	5	3,948.050	6,181.270	0.74%
	6	2,481.780	3,946.150	1.00%
	7	1,422.890	2,464.500	1.19%
	8	731.190	1,417.450	0.88%
	9	304.620	729.920	1.73%
Smallest	10	1.110	304.480	4.47%

*From 2025 Kroll Cost of Capital Navigator

Notes:

(1) From page 2 of this Schedule.

(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].

(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.

(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.00% in Column [4], Line No. 2 is derived as follows 0.00% = 0.74% - 0.74%.

UGI Utilities, Inc.
Market Capitalization of UGI Utilities, Inc. and the
Proxy Group of Seven Natural Gas Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2024 (millions)	[2] Book Value per Share at Fiscal Year End 2024 (1)	[3] Total Common Equity at Fiscal Year End 2024 (millions)	[4] Closing Stock Market Price on October 31, 2025	[5] Market-to-Book Ratio on October 31, 2025 (2)	[6] Market Capitalization on October 31, 2025 (3) (millions)
UGI Utilities, Inc.		NA	NA	$ 1,998.554 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Companies						200.2 (5)	$ 4,001.105 (6)
Proxy Group of Seven Natural Gas Companies							
Atmos Energy Corporation	NYSE	$ 155.26	$ 78.306	$ 12,157.67	$ 171.720	219.3 %	$ 26,661.049
Chesapeake Utilities Corporation	NYSE	22.899	60.710	1,390.20	127.280	209.7	2,914.585
New Jersey Resources Corporation	NYSE	99.461	22.124	2,200.44	44.300	200.2	4,406.142
NiSource Inc.	NYSE	469.822	18.484	8,684.20	42.110	227.8	19,784.224
Northwest Natural Holding Company	NYSE	40.222	34.443	1,385.37	45.530	132.2	1,831.322
ONE Gas, Inc.	NYSE	59.877	51.849	3,104.55	80.190	154.7	4,801.525
Southwest Gas Holdings, Inc.	NYSE	71.783	48.817	3,504.19	79.500	162.9	5,706.729
Median		$ 71.78	$ 48.82	$ 3,104.55	$ 79.50	200.200 %	$ 4,801.525

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of UGI Utilities, Inc. on October 31, 2025 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Companies on October 31, 2025 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2024 Annual Forms 10K
Bloomberg Professional

UGI Utilities, Inc.
R-Squareds of Betas for the
Proxy Group of Seven Natural Gas Companies

Company Name	Adjusted VL Beta	Correlation Coefficient	R-Squared
Atmos Energy Corporation	0.75	0.4593	0.2110
Chesapeake Utilities Corporation	0.70	0.3484	0.1214
New Jersey Resources Corporation	0.80	0.4429	0.1962
NiSource Inc.	0.80	0.5156	0.2658
Northwest Natural Holding Company	0.75	0.3895	0.1517
ONE Gas, Inc.	0.75	0.3746	0.1403
Southwest Gas Holdings, Inc.	0.75	0.3763	0.1416
Average			0.1754

Source of Information: Value Line Proprietary Database September 2025

UGI Utilities, Inc.
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances

Date of Offering	Transaction (1)	[Column 1] Shares Issued (1)	[Column 2] Average Offering Price per Share (1)	[Column 3] Total Offering Expense per Share (1)	[Column 4] Net Proceeds per Share (2)	[Column 5] Gross Equity Issue before Costs (3)	[Column 6] Total Net Proceeds (4)	[Column 7] Total Flotation Costs (5)	[Column 8] Flotation Cost Percentage (6)
5/25/2021	Equity Unit Offering	5,054,030	$ 100.00	$ 3.000	$ 97.0000	$505,403,000	$490,240,910	$ 15,162,090	3.00%
3/24/2004	Equity Offering	7,500,000	$ 32.10	$ 1.404	$ 30.6956	$240,750,000	$230,217,000	$ 10,533,000	4.38%
	Total Public Issuances					$746,153,000	$720,457,910	$ 25,695,090	3.44%

Flotation Cost Adjustment

	[Column 9] Average Dividend Yield (7)	[Column 10] Average Projected EPS Growth Rate (7)	[Column 11] Adjusted Dividend Yield (8)	[Column 12] Average DCF Cost Rate Unadjusted for Flotation (9)	[Column 13] DCF Cost Rate Adjusted for Flotation (10)	[Column 14] Flotation Cost Adjustment (11)
Proxy Group of Seven Natural Gas Companies	3.15 %	7.62 %	3.27 %	10.89 %	11.01 %	0.12 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 1 x Col. 2
(4) Col. 1 x Col. 4
(5) Col. 1 x Col. 3
(6) (Col. 5 - Col. 6) / Col. 5
(7) From page 1 of Schedule DWD-3.
(8) Col. 9 * (1 + (0.5 * Col. 10))
(9) Col. 10 + Col. 11
(10) (Col. 11 / (1 - Col. 8)) + Col. 10
(11) Col. 13 - Col. 12

UGI Utilities, Inc.
Hypothetical Example: Flotation Cost Recovery

Return on Equity	10.75%
Flotation Costs	2.75%
Market Value	$ 25.00
Dividend Yield	3.50%
Growth Rate	7.25%
Adjusted ROE	10.85%
Flotation Cost Recovery:	**No**
DCF Estimate	**10.65%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.31		$ 24.31	$ 25.00	1.0283	$ 2.61	$ 0.88	33.48%
2	$ 24.31	$ 1.74	$ 26.05	$ 26.79	1.0283	$ 2.80	$ 0.94	33.48%
3	$ 24.31	$ 3.60	$ 27.91	$ 28.70	1.0283	$ 3.00	$ 1.00	33.48%
4	$ 24.31	$ 5.60	$ 29.91	$ 30.76	1.0283	$ 3.22	$ 1.08	33.48%
5	$ 24.31	$ 7.74	$ 32.05	$ 32.96	1.0283	$ 3.45	$ 1.15	33.48%
6	$ 24.31	$ 10.03	$ 34.34	$ 35.31	1.0283	$ 3.69	$ 1.24	33.48%
7	$ 24.31	$ 12.48	$ 36.80	$ 37.84	1.0283	$ 3.96	$ 1.32	33.48%
8	$ 24.31	$ 15.12	$ 39.43	$ 40.54	1.0283	$ 4.24	$ 1.42	33.48%
9	$ 24.31	$ 17.94	$ 42.25	$ 43.44	1.0283	$ 4.54	$ 1.52	33.48%
10	$ 24.31	$ 20.96	$ 45.27	$ 46.55	1.0283	$ 4.87	$ 1.63	33.48%
	Growth Rate		7.15%	7.15%		7.15%	7.15%	

Return on Equity	10.75%
Flotation Costs	2.75%
Market Value	$ 25.00
Dividend Yield	3.50%
Growth Rate	7.25%
Adjusted ROE	10.85%
Flotation Cost Recovery:	**Yes**
DCF Estimate	**10.75%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.31		$ 24.31	$ 25.00	1.0283	$ 2.64	$ 0.88	33.17%
2	$ 24.31	$ 1.76	$ 26.08	$ 26.81	1.0283	$ 2.83	$ 0.94	33.17%
3	$ 24.31	$ 3.65	$ 27.97	$ 28.76	1.0283	$ 3.03	$ 1.01	33.17%
4	$ 24.31	$ 5.68	$ 29.99	$ 30.84	1.0283	$ 3.25	$ 1.08	33.17%
5	$ 24.31	$ 7.86	$ 32.17	$ 33.08	1.0283	$ 3.49	$ 1.16	33.17%
6	$ 24.31	$ 10.19	$ 34.50	$ 35.48	1.0283	$ 3.74	$ 1.24	33.17%
7	$ 24.31	$ 12.69	$ 37.00	$ 38.05	1.0283	$ 4.01	$ 1.33	33.17%
8	$ 24.31	$ 15.37	$ 39.68	$ 40.81	1.0283	$ 4.31	$ 1.43	33.17%
9	$ 24.31	$ 18.25	$ 42.56	$ 43.76	1.0283	$ 4.62	$ 1.53	33.17%
10	$ 24.31	$ 21.33	$ 45.65	$ 46.94	1.0283	$ 4.95	$ 1.64	33.17%
	Growth Rate		7.25%	7.25%		7.25%	7.25%	

UGI GAS

EXHIBIT E

PROOF OF REVENUE

UGI Utilities, Inc. - Gas Division
Proof of Revenue Summary - Total Revenue
for the 12-Months Ending September 30, 2027

Rate Class	Customers	Sales	Present Revenue	Proposed Revenue	Revenue Change	Percent Change from Present Revenue	Percent of Total Rate Increase
R/RT	634,252	50,491,037	$ 794,637,988	$ 869,313,264	$ 74,675,276	9.4%	75.2%
N/NT	69,690	30,008,036	$ 269,053,409	$ 292,438,718	$ 23,385,309	8.7%	23.5%
DS	1,305	8,868,042	$ 36,009,619	$ 36,718,468	$ 708,849	2.0%	0.7%
LFD	638	27,341,950	$ 58,767,849	$ 59,503,827	$ 735,978	1.3%	0.7%
XD - Firm	54	207,826,615	$ 39,138,908	$ 39,074,556	$ (64,353)	-0.2%	-0.1%
Interruptible	293	14,668,550	$ 22,943,504	$ 22,870,189	$ (73,315)	-0.3%	-0.1%
Total	706,232	339,204,231	$ 1,220,551,277	$ 1,319,919,022	$ 99,367,745	8.1%	
Other Operating Revenue			$ 14,131,000	$ 14,131,000	$ -		
Total	706,232	339,204,231	$ 1,234,682,277	$ 1,334,050,022	$ 99,367,745	8.0%	

UGI Utilities, Inc. - Gas Division
Residential Service - Rate Schedules R & RT
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charges	7,611,024		$ 16.25	$ 123,679,140	$ 23.00	$ 175,053,552	$ 51,374,412	
Distribution Charges		50,491,037	$ 6.3317	$ 319,694,099	$ 6.8383	$ 345,272,858	$ 25,578,759	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 79,456	0.00%	$ -	$ (79,456)	
Purchased Gas Costs (PGC) - Rider B		44,265,497	$ 6.7486	$ 298,730,133	$ 6.7486	$ 298,730,133	$ -	
Merchant Function Charge (MFC) - Rider D		44,265,497	2.56%	$ 7,647,491	2.37%	$ 7,079,904	$ (567,587)	
Gas Procurement Charge (GPC) - Rider E		44,265,497	$ 0.0660	$ 2,921,523	$ 0.0660	$ 2,921,523	$ -	
Universal Service Program (USP) - Rider F		47,870,552	$ 0.6363	$ 30,460,032	$ 0.6363	$ 30,460,032	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider G		50,491,037	$ 0.1940	$ 9,795,261	$ 0.1940	$ 9,795,261	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 1,630,852	0.00%	$ -	$ (1,630,852)	
Total - Rates R/RT	**7,611,024**	**50,491,037**		**$ 794,637,988**		**$ 869,313,264**	**$ 74,675,276**	**9.4%**

UGI Utilities, Inc. - Gas Division
Non-Residential Service - Rate Schedules N & NT
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charges	836,280		$ 36.42	$ 30,457,318	$ 39.00	$ 32,614,920	$ 2,157,602	
Distribution Charges		30,008,036	$ 4.3004	$ 129,046,558	$ 5.0297	$ 150,931,419	$ 21,884,861	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 26,903	0.00%	$ -	$ (26,903)	
Purchased Gas Costs (PGC) - Rider B		15,791,724	$ 6.7486	$ 106,572,029	$ 6.7486	$ 106,572,029	$ -	
Merchant Function Charge (MFC) - Rider D		15,791,724	0.56%	$ 596,803	0.47%	$ 500,889	$ (95,915)	
Gas Procurement Charge (GPC) - Rider E		15,791,724	$ 0.0660	$ 1,042,254	$ 0.0660	$ 1,042,254	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider G		30,008,036	$ 0.0259	$ 777,208	$ 0.0259	$ 777,208	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 534,336	0.00%	$ -	$ (534,336)	
Total - Rates N/NT	**836,280**	**30,008,036**		**$ 269,053,409**		**$ 292,438,718**	**$ 23,385,309**	**8.7%**

UGI Utilities, Inc. - Gas Division
Delivery Service - Rate Schedule DS
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charges	15,660		$ 300.00	$ 4,698,000	$ 353.00	$ 5,527,980	$ 829,980	
Distribution Charges		8,868,042	$ 3.3651	$ 29,841,847	$ 3.3652	$ 29,842,734	$ 887	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 3,601	0.00%	$ -	$ (3,601)	
Energy Efficiency & Conservation Rider (EEC) - Rider G		8,868,042	$ 0.0449	$ 398,175	$ 0.0449	$ 398,175	$ -	
Technology and Economic Development Rider (TED) - Rider H				$ 692,336		$ 692,336	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 118,417	0.00%	$ -	$ (118,417)	
Gas Delivery Enhancement Rider (GDE) - Rider J		8,868,042	$ 0.0004	$ 3,547	$ 0.0004	$ 3,547	$ -	
Minimum Charges				$ 253,695		$ 253,695	$ -	
Total - Rate DS	**15,660**	**8,868,042**		**$ 36,009,619**		**$ 36,718,468**	**$ 708,849**	**2.0%**

UGI Utilities, Inc. - Gas Division
Large Firm Delivery Service - Rate Schedule LFD
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	7,656		$ 670.00	$ 5,129,520	$ 670.00	$ 5,129,520	$ -	
Distribution Charge		27,341,950	$ 1.3831	$ 37,816,651	$ 1.4173	$ 38,751,746	$ 935,095	
Demand Charge		1,533,062	$ 7.6956	$ 11,797,835	$ 7.6956	$ 11,797,835	$ -	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 5,876	0.00%	$ -	$ (5,876)	
Energy Efficiency & Conservation Rider (EEC) - Rider G		27,341,950	$ 0.0357	$ 976,108	$ 0.0357	$ 976,108	$ -	
Technology and Economic Development Rider (TED) - Rider H				$ 335,160		$ 335,160	$ -	
Minimum Bills				$ 1,887,181		$ 1,887,181	$ -	
Excess Requirement Option				$ 615,341		$ 615,341	$ -	
Excess Take				$ -		$ -	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 193,241	0.00%	$ -	$ (193,241)	
Gas Delivery Enhancement Rider (GDE) - Rider J		27,341,950	$ 0.0004	$ 10,937	$ 0.0004	$ 10,937	$ -	
Total - Rate LFD	**7,656**	**27,341,950**		**$ 58,767,849**		**$ 59,503,827**	**$ 735,978**	**1.3%**

UGI Utilities, Inc. - Gas Division
Extended Large Firm Delivery Service - Rate Schedule XD
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	648		$ 37,190.68	$ 24,099,561	$ 37,190.68	$ 24,099,561	$ -	
Distribution Charge		207,826,615	$ 0.0624	$ 12,976,418	$ 0.0624	$ 12,976,418	$ -	
Excess Requirement Option		1,500	$ 4.5000	$ 6,750	$ 4.5000	$ 6,750	$ -	
Demand Charges		230,040	$ 5.3314	$ 1,226,431	$ 5.3314	$ 1,226,431		
Minimum Charges				$ 765,396		$ 765,396	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 64,353	0.00%	$ -	$ (64,353)	
Total - Rate XD	**648**	**207,826,615**		**$ 39,138,908**		**$ 39,074,556**	**$ (64,353)**	**-0.2%**

UGI Utilities, Inc. - Gas Division
Interruptible Service - Rate Schedule IS
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	3,516		$ 1,411.68	$ 4,963,460	$ 1,411.68	$ 4,963,460	$ -	
Distribution Charge		14,668,550	$ 1.1982	$ 17,576,501	$ 1.1982	$ 17,576,501	$ -	
Minimum Charges				$ 330,229		$ 330,229	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 73,315	0.00%	$ -	$ (73,315)	
Total - Rate IS	**3,516**	**14,668,550**		**$ 22,943,504**		**$ 22,870,189**	**$ (73,315)**	**-0.3%**

BOOK VI

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C
(FULLY PROJECTED FUTURE)
2027 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF SEPTEMBER 30, 2027

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI Gas Exhibit C (Fully Projected Future)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2027

Prepared by:

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT SEPTEMBER 30, 2027

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming Valuation and Rate Consultants, LLC
(a GFT Company)

300 Sterling Parkway, Suite 200
Mechanicsburg, PA 17050
717.763.7211

January 12, 2026

Jessica R. Rogers
Vice President – Rates and Regulatory Affairs
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant at September 30, 2027 for the consolidated UGI gas company. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 through 4 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Gas Exhibit C (Future), "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2026".

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

085304.100

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PART I. INTRODUCTION

UGI UTILITIES, INC. – GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. – Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2027.

BASIS OF STUDY

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2027, are set forth in Table 1 and are based on company data through 2022. The service life estimates are the same estimates as submitted to the Pennsylvania Public Utility Commission (PA PUC) in May 2023 in connection with the company's most recent service life study report.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2027, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2027, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages II-3 through II-11 summarize the results of the depreciation study as of September 30, 2027 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2027, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the bringforward of the book reserve to September 30, 2027. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2027. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2023 through 2027.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced and estimated cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 4 which presents the five-year amortization.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2027

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT	COMPOSITE REMAINING LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GAS PLANT									
PRODUCTION PLANT									
305	MANUFACTURED GAS PLANT SITE REMEDIATION			0	0	0	-	0	0.0
329	OTHER STRUCTURES			0	0	0	-	0	0.0
332	FIELD LINES			0	0	0	-	0	0.0
335	DRILLING AND CLEANING EQUIPMENT			0	0	0	-	0	0.0
TOTAL PRODUCTION PLANT				**0**	**0**	**0**	**-**	**0**	**0.0**
TRANSMISSION PLANT									
365.2	RIGHTS-OF-WAY		70 - R4	868,160	594,389	273,771	1.26	10,902	25.1
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	157,263	4,953	0.17	271	18.3
367	MAINS		75 - R2.5	39,468,181	23,931,881	15,536,300	1.01	399,385	38.9
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2.5	6,172,834	4,437,172	1,735,662	1.40	86,642	20.0
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,505,204	2,630,636	874,568	2.19	76,632	11.4
371	OTHER EQUIPMENT		35 - R2.5	140,637	134,860	5,777	0.56	787	7.3
371.1	TESTING EQUIPMENT		20 - R3	210,011	176,829	33,182	2.01	4,216	7.9
TOTAL TRANSMISSION PLANT				**50,527,243**	**32,063,030**	**18,464,213**	**1.15**	**578,835**	**31.9**
DISTRIBUTION PLANT									
374.2	RIGHTS-OF-WAY		75 - R3	3,374,004	1,594,150	1,779,854	1.26	42,665	41.7
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	7,923,019	3,846,439	4,076,580	1.82	144,227	28.3
376.1	MAINS - PRIMARILY STEEL		75 - R2.5	816,343,179	220,451,099	595,892,080	1.51	12,366,899	48.2
376.2	MAINS - CAST IRON	09-2027	65 - R1	664,766	664,769	(3)	-	0	0.0
376.3	MAINS - PLASTIC		68 - R3	2,371,718,284	422,700,224	1,949,018,060	1.64	38,991,101	50.0
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	305,201	266,181	39,020	1.56	4,749	8.2
376.7	REG AFUDC		40 - SQ	1,322,088	329,843	992,245	2.50	33,052	30.0
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		48 - S0	229,058,181	51,379,895	177,678,286	2.74	6,274,505	28.3
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R1.5	81,779,825	18,453,572	63,326,253	2.73	2,234,071	28.3
380	SERVICES		45 - R2	1,937,403,605	508,597,998	1,428,805,607	2.67	51,721,129	27.6
381	METERS		36 - R2	169,884,761	70,109,842	99,774,919	2.75	4,671,295	21.4
381.1	METERS - ERTS		17 - S3	49,518,244	21,630,260	27,887,984	6.42	3,179,453	8.8
382	METER INSTALLATIONS		45 - R2	153,631,673	52,437,651	101,194,022	2.41	3,708,944	27.3
383	HOUSE REGULATORS		45 - R2	10,274,123	6,278,044	3,996,079	2.01	206,374	19.4
384	HOUSE REGULATOR INSTALLATIONS		45 - R2	17,829,357	10,128,089	7,701,268	1.79	318,884	24.2
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	42,670,641	22,284,010	20,386,631	1.87	797,604	25.6
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		45 - R2	68,824	44,596	24,228	2.05	1,414	17.1
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R1.5	1,180,774	659,589	521,185	2.14	25,261	20.6
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,705	0	-	0	0.0
387	OTHER EQUIPMENT		40 - R2.5	5,308,206	3,405,789	1,902,417	1.64	87,088	21.8
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,488,355	2,309	0.15	2,309	1.0
TOTAL DISTRIBUTION PLANT				**5,901,774,124**	**1,416,775,100**	**4,484,999,024**	**2.11**	**124,811,024**	**35.9**
GENERAL PLANT									
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS*	183,834,899	61,262,838	122,572,061	3.89	7,154,215	17.1
390.3	CNG STATIONS		15 - S3	7,022,614	753,027	6,269,587	7.15	501,969	12.5
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,884,524	2,451,215	3,433,309	5.48	322,668	10.6
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	249,370	100,398	148,972	11.17	27,845	5.4
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	13,631,489	9,567,172	4,064,317	14.79	2,016,027	2.0
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAR		10 - SQ	5,397,504	2,777,598	2,619,906	8.99	485,445	5.4
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEAR		15 - SQ	43,977,025	13,235,056	30,741,969	6.63	2,914,581	10.5
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,667,253	3,536,013	1,131,240	6.91	322,732	3.5
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	61,236,851	24,639,835	36,597,016	10.41	6,376,417	5.7
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL		12 - L3	7,626,640	4,261,968	3,364,672	7.49	570,922	5.9

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2027

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE		CALCULATED ANNUAL ACCRUAL AMOUNT	COMPOSITE REMAINING LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	11,059,662	5,541,637	5,518,025	7.64		844,799	6.5
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,944,491	1,518,810	1,425,681	5.87		172,826	8.2
393	STORES EQUIPMENT		20 - SQ	15,838	8,640	7,198	5.00		792	9.1
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	46,258,749	18,442,253	27,816,496	5.10		2,359,760	11.8
395	LABORATORY EQUIPMENT		20 - SQ	437,779	223,369	214,410	5.13		22,439	9.6
396	POWER OPERATED EQUIPMENT		16 - L2	13,798,162	6,979,558	6,818,604	6.04		832,914	8.2
397	COMMUNICATION EQUIPMENT		10 - SQ	2,364,137	752,256	1,611,881	11.18		264,280	6.1
398	MISCELLANEOUS EQUIPMENT		15 - SQ	2,319,953	1,222,745	1,097,208	3.69		85,708	12.8
399	OTHER TANGIBLE PROPERTY			0	0	0	-		0	0.0
TOTAL GENERAL PLANT				**412,726,940**	**157,274,388**	**255,452,552**	**6.10**		**25,276,339**	**10.1**
TOTAL DEPRECIABLE GAS PLANT				**6,365,028,307**	**1,606,112,518**	**4,758,915,789**	**2.37**		**150,666,198**	**31.6**
NONDEPRECIABLE PLANT										
301	ORGANIZATION			166,478						
302	FRANCHISES AND CONSENTS			193,597						
303	MISCELLANEOUS INTANGIBLE PLANT			289,868						
365.1	LAND			47,323						
374.1	LAND AND LAND RIGHTS - LAND			803,858						
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,459,999						
389.1	LAND AND LAND RIGHTS - LAND			7,936,470						
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313						
TOTAL NONDEPRECIABLE PLANT				**16,898,906**						
TOTAL GAS PLANT				**6,381,927,213**						
OTHER UTILITY PLANT										
COMMON PLANT										
301	ORGANIZATION (NONDEPRECIABLE)			138,964						
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108						
390.1	STRUCTURES AND IMPROVEMENTS									
	UGI HEADQUARTERS BUILDING - DENVER	01-2069	70 - R1	35,294,802	7,650,836	27,643,966	2.50		881,875	31.3
	READING DATA CENTER	09-2073	70 - R1	20,414,469	2,461,462	17,953,007	2.72		556,041	32.3
	KNITTING MILLS OFFICE	06-2050	70 - R1	1,382,240	315,949	1,066,291	3.86		53,288	20.0
	TOTAL ACCOUNT 390.1			*57,091,511*	*10,428,247*	*46,663,264*	*2.61*		*1,491,204*	*31.3*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,976,544	1,734,257	3,242,287	5.12		254,975	12.7
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	0	0	0	20.00	**	0	
TOTAL COMMON PLANT				**69,154,127**	**12,162,504**	**49,905,551**	**2.81**		**1,746,179**	**28.6**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%				**61,623,243**	**10,838,007**	**44,470,836**			**1,556,020**	

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2027

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
INFORMATION SERVICES (IS)								
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,877,324	13,076,764	4,800,560	15.53	2,776,568	1.7
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
SUCCESS FACTORS	09-2024	SQUARE	2,803,866	2,803,866	0	-	0	0.0
UNITE ERP	09-2034	SQUARE	10,695,816	5,347,641	5,348,175	7.14	764,025	7.0
TOTAL ACCOUNT 391.2			*13,499,682*	*8,151,507*	*5,348,175*	*5.66*	*764,025*	*7.0*
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	111,013,417	37,514,115	73,499,302	10.19	11,310,582	6.5
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,296,653	83,072,623	51,224,030	6.82	9,155,825	5.6
TOTAL INFORMATION SERVICES			**276,687,076**	**141,815,009**	**134,872,067**	**8.68**	**24,007,000**	**5.6**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%			**234,685,978**	**120,287,491**	**114,398,487**		**20,362,737**	
EMPIRE YARD BUILDING								
390.1 STRUCTURES AND IMPROVEMENTS			12,832,326	9,120,412	3,711,914	1.53	195,693	19.0
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,677,185**	**1,192,038**	**485,147**		**25,577**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**294,632,036**	**129,933,460**	**158,384,176**		**21,893,180**	
TOTAL PLANT IN SERVICE			**6,676,559,249**	**1,736,045,978**	**4,917,299,965**		**172,559,378**	
AMORTIZATION OF NEGATIVE NET SALVAGE							**9,702,837**	
GRAND TOTAL			**6,676,559,249**	**1,736,045,978**	**4,917,299,965**		**182,262,215**	

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** RATE TO APPLY TO FUTURE PLANT IN-SERVICE

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2026 PROJECTED TO SEPTEMBER 30, 2027

ACCOUNT		BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GAS PLANT										
PRODUCTION PLANT										
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0	0	0	0	0	0	0	0.00
329	OTHER STRUCTURES	0	0	0	0	0	0	0	0	0.00
332	FIELD LINES	0	0	0	0	0	0	0	0	0.00
335	DRILLING AND CLEANING EQUIPMENT	0	0	0	0	0	0	0	0	0.00
TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.00**
TRANSMISSION PLANT										
365.2	RIGHTS-OF-WAY	583,277	11,112	0	0	0	0	0	594,389	68.47
366	STRUCTURES AND IMPROVEMENTS	156,987	276	0	0	0	0	0	157,263	96.95
367	MAINS	23,526,057	402,575	3,249	0	0	0	0	23,931,881	60.64
369	MEASURING AND REGULATING STATION EQUIPMENT	4,347,592	88,553	1,027	0	0	0	0	4,437,172	71.88
370	COMMUNICATION EQUIPMENT	2,549,221	81,415	0	0	0	0	0	2,630,636	75.05
371	OTHER EQUIPMENT	133,995	865	0	0	0	0	0	134,860	95.89
371.1	TESTING EQUIPMENT	172,428	4,401	0	0	0	0	0	176,829	84.20
TOTAL TRANSMISSION PLANT		**31,469,557**	**589,197**	**4,276**	**0**	**0**	**0**	**0**	**32,063,030**	**63.46**
DISTRIBUTION PLANT										
374.2	RIGHTS-OF-WAY	1,551,251	42,899	0	0	0	0	0	1,594,150	47.25
375	STRUCTURES AND IMPROVEMENTS	3,693,851	148,281	4,307	0	0	0	0	3,846,439	48.55
376.1	MAINS - PRIMARILY STEEL	211,746,999	12,013,881	1,383,832	(3,346,366)	0	(1,347,246)	0	220,451,100	27.00
376.2	MAINS - CAST IRON	664,766	1,286	0	0	0	0	(1,283)	664,769	100.00
376.3	MAINS - PLASTIC	390,033,008	36,606,958	1,202,640	(4,272,502)	0	(871,163)	1,283	422,700,224	17.82
376.5	MAINS - PRIMARILY WROUGHT IRON	261,046	5,135	0	0	0	0	0	266,181	87.21
376.7	REG AFUDC	300,224	29,619	0	0	0	0	0	329,843	24.95
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	46,205,293	5,340,005	203,490	(295,115)	0	(73,778)	0	51,379,895	22.43
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	16,033,091	2,335,776	84,705	0	0	0	0	18,453,572	22.56
380	SERVICES	485,016,289	49,142,478	5,360,143	(22,262,878)	0	(8,658,034)	0	508,597,998	26.25
381	METERS	67,493,856	4,417,364	31,896	(1,833,274)	0	0	0	70,109,842	41.27
381.1	METERS - ERTS	19,347,248	3,157,357	6,109	(880,454)	0	0	0	21,630,260	43.68
382	METER INSTALLATIONS	50,079,255	3,619,098	156,549	(1,020,412)	0	(396,838)	0	52,437,652	34.13
383	HOUSE REGULATORS	5,133,343	273,178	871,523	0	0	0	0	6,278,044	61.11
384	HOUSE REGULATOR INSTALLATIONS	9,800,803	326,258	1,028	0	0	0	0	10,128,089	56.81
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	21,130,913	807,779	(47,619)	(9,630)	0	402,567	0	22,284,010	52.22
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	42,958	1,483	155	0	0	0	0	44,596	64.80
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	632,918	26,424	247	0	0	0	0	659,589	55.86
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	0	0	0	24,705	100.00
387	OTHER EQUIPMENT	3,316,734	89,055	0	0	0	0	0	3,405,789	64.16
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,485,147	3,208	0	0	0	0	0	1,488,355	99.85
TOTAL DISTRIBUTION PLANT		**1,333,993,698**	**118,387,521**	**9,259,005**	**(33,920,631)**	**0**	**(10,944,492)**	**0**	**1,416,775,101**	**24.01**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2026 PROJECTED TO SEPTEMBER 30, 2027

ACCOUNT	BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GENERAL PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	55,336,908	6,658,988	137,932	(799,294)	0	(71,696)	0	61,262,838	33.32
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	0	0	0	0.00
390.3 CNG STATIONS	251,058	501,969	0	0	0	0	0	753,027	0.00
391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	2,231,975	324,241	0	(105,002)	0	0	0	2,451,214	41.66
391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	89,606	23,093	0	(12,301)	0	0	0	100,398	40.26
391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	7,096,550	2,855,714	0	(385,092)	0	0	0	9,567,172	70.18
391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	0	0	0	0	0	0	0	0	0.00
391.41 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	2,343,072	483,966	0	(49,440)	0	0	0	2,777,598	51.46
391.42 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	10,694,286	2,905,940	0	(365,170)	0	0	0	13,235,056	30.10
392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	3,148,010	390,841	(909)	(2,143)	214	0	0	3,536,013	75.76
392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	21,105,714	5,357,281	(783,593)	(1,155,074)	115,507	0	0	24,639,835	40.24
392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	3,663,559	603,047	(1,486)	(3,502)	350	0	0	4,261,968	55.88
392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	4,673,510	874,853	(2,155)	(5,079)	508	0	0	5,541,637	50.11
392.5 TRANSPORTATION EQUIPMENT - TRAILERS	1,338,963	181,638	(574)	(1,352)	135	0	0	1,518,810	51.58
393 STORES EQUIPMENT	7,849	791	0	0	0	0	0	8,640	54.55
394 TOOLS, SHOP AND GARAGE EQUIPMENT	17,652,042	2,312,041	4,379	(1,526,210)	0	0	0	18,442,252	39.87
395 LABORATORY EQUIPMENT	200,930	22,439	0	0	0	0	0	223,369	51.02
396 POWER OPERATED EQUIPMENT	6,098,760	880,798	0	0	0	0	0	6,979,558	50.58
397 COMMUNICATION EQUIPMENT	1,216,151	264,898	2,520	(731,313)	0	0	0	752,256	31.82
398 MISCELLANEOUS EQUIPMENT	1,208,168	60,593	78,169	(124,185)	0	0	0	1,222,745	52.71
399 OTHER TANGIBLE PROPERTY	0	0	0	0	0	0	0	0	0.00
TOTAL GENERAL PLANT	**138,357,111**	**24,703,132**	**(565,717)**	**(5,265,157)**	**116,714**	**(71,696)**	**0**	**157,274,387**	**38.77**
TOTAL DEPRECIABLE GAS PLANT	**1,503,820,366**	**143,679,849**	**8,697,564**	**(39,185,788)**	**116,714**	**(11,016,188)**	**0**	**1,606,112,517**	**25.26**
OTHER UTILITY PLANT									
COMMON PLANT									
390.1 STRUCTURES AND IMPROVEMENTS									
UGI HEADQUARTERS BUILDING - DENVER	6,755,017	895,819	0	0	0	0	0	7,650,836	21.68
READING DATA CENTER	1,880,978	580,484	0	0	0	0	0	2,461,462	12.06
KNITTING MILLS OFFICE	261,435	54,514	0	0	0	0	0	315,949	22.86
TOTAL ACCOUNT 390.1	*8,897,430*	*1,530,817*	*0*	*0*	*0*	*0*	*0*	*10,428,247*	
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,481,740	252,517	0	0	0	0	0	1,734,257	34.85
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	0	0	0	0	0	0	0	0	0.00
TOTAL COMMON PLANT	**10,379,170**	**1,783,334**	**0**	**0**	**0**	**0**	**0**	**12,162,504**	**19.60**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%	**9,248,878**	**1,589,129**	**0**	**0**	**0**	**0**	**0**	**10,838,007**	
INFORMATION SERVICES (IS)									
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	9,593,313	3,483,451	0	0	0	0	0	13,076,764	73.15
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE									
SUCCESS FACTORS	2,803,866	0	0	0	0	0	0	2,803,866	100.00
UNITE ERP	4,583,616	764,025	0	0	0	0	0	5,347,641	50.00
TOTAL ACCOUNT 391.2	*7,387,482*	*764,025*	*0*	*0*	*0*	*0*	*0*	*8,151,507*	
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	28,933,224	9,881,444	0	(1,300,552)	0	0	0	37,514,115	33.79
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	73,969,743	9,139,001	0	(36,121)	0	0	0	83,072,623	61.86
TOTAL INFORMATION SERVICES	**119,883,762**	**23,267,921**	**0**	**(1,336,673)**	**0**	**0**	**0**	**141,815,010**	**51.25**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%	**101,685,407**	**19,735,851**	**0**	**(1,133,766)**	**0**	**0**	**0**	**120,287,491**	
EMPIRE YARD BUILDING									
390.1 STRUCTURES AND IMPROVEMENTS	8,904,887	189,490	57,984	(29,319)	0	(2,630)	0	9,120,412	71.07
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,163,869**	**24,766**	**7,578**	**(3,832)**	**0**	**(344)**	**0**	**1,192,038**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION	**109,770,416**	**21,300,214**	**(7,578)**	**(1,129,934)**	**0**	**344**	**0**	**129,933,460**	
TOTAL DEPRECIABLE PLANT IN SERVICE	**1,613,590,782**	**164,980,063**	**8,689,986**	**(40,315,722)**	**116,714**	**(11,015,844)**	**0**	**1,736,045,977**	

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2027

ACCOUNT		BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GAS PLANT									
PRODUCTION PLANT									
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0	0	0	0	0	-	0
329	OTHER STRUCTURES	0	0	0	0	0	0	-	0
332	FIELD LINES	0	0	0	0	0	0	-	0
335	DRILLING AND CLEANING EQUIPMENT	0	0	0	0	0	0	-	0
TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	-	**0**
TRANSMISSION PLANT									
365.2	RIGHTS-OF-WAY	868,160	0	0	0	868,160	868,160	1.28	11,112
366	STRUCTURES AND IMPROVEMENTS	162,216	0	0	0	162,216	162,216	0.17	276
367	MAINS	39,468,181	0	0	0	39,468,181	39,468,181	1.02	402,575
369	MEASURING AND REGULATING STATION EQUIPMENT	6,172,834	0	0	0	6,172,834	6,172,834	1.43	88,553
370	COMMUNICATION EQUIPMENT	3,505,204	0	0	0	3,505,204	3,505,204	2.32	81,415
371	OTHER EQUIPMENT	140,637	0	0	0	140,637	140,637	0.62	865
371.1	TESTING EQUIPMENT	210,011	0	0	0	210,011	210,011	2.10	4,401
TOTAL TRANSMISSION PLANT		**50,527,243**	**0**	**0**	**0**	**50,527,243**	**50,527,243**		**589,197**
DISTRIBUTION PLANT									
374.2	RIGHTS-OF-WAY	3,374,004	0	0	0	3,374,004	3,374,004	1.27	42,899
375	STRUCTURES AND IMPROVEMENTS	7,923,019	0	0	0	7,923,019	7,923,019	1.87	148,281
376.1	MAINS - PRIMARILY STEEL	787,125,750	32,563,794	(3,346,366)	0	816,343,178	801,734,464	1.52	12,013,881
376.2	MAINS - CAST IRON	664,766	0	0	0	664,766	664,766	0.19	1,286
376.3	MAINS - PLASTIC	2,166,671,780	209,319,006	(4,272,502)	0	2,371,718,284	2,269,195,032	1.64	36,606,958
376.5	MAINS - PRIMARILY WROUGHT IRON	305,201	0	0	0	305,201	305,201	1.68	5,135
376.7	REG AFUDC	1,322,088	0	0	0	1,322,088	1,322,088	2.50	29,619
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	191,451,499	37,901,797	(295,115)	0	229,058,181	210,254,840	2.69	5,340,005
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	81,779,825	0	0	0	81,779,825	81,779,825	2.86	2,335,776
380	SERVICES	1,799,933,111	159,733,372	(22,262,878)	0	1,937,403,605	1,868,668,358	2.65	49,142,478
381	METERS	160,820,610	10,897,425	(1,833,274)	0	169,884,761	165,352,686	2.72	4,417,364
381.1	METERS - ERTS	44,949,985	5,448,712	(880,454)	0	49,518,243	47,234,114	6.83	3,157,357
382	METER INSTALLATIONS	147,330,759	7,321,326	(1,020,412)	0	153,631,673	150,481,216	2.41	3,619,098
383	HOUSE REGULATORS	10,274,123	0	0	0	10,274,123	10,274,123	2.66	273,178
384	HOUSE REGULATOR INSTALLATIONS	17,829,357	0	0	0	17,829,357	17,829,357	1.83	326,258
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	41,443,487	1,236,784	(9,630)	0	42,670,641	42,057,064	1.92	807,779
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	68,824	0	0	0	68,824	68,824	2.15	1,483
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	1,180,774	0	0	0	1,180,774	1,180,774	2.24	26,424
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	24,705	24,705	-	0
387	OTHER EQUIPMENT	5,308,206	0	0	0	5,308,206	5,308,206	1.68	89,055
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	0	0	0	1,490,664	1,490,664	0.22	3,208
TOTAL DISTRIBUTION PLANT		**5,471,272,537**	**464,422,216**	**(33,920,631)**	**0**	**5,901,774,122**	**5,686,523,330**		**118,387,521**
GENERAL PLANT									
390.1	STRUCTURES AND IMPROVEMENTS	168,008,808	16,625,384	(799,294)	0	183,834,898	175,921,853	3.93	6,658,988
390.3	CNG STATIONS	7,022,614	0	0	0	7,022,614	7,022,614	7.15	501,969
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,843,693	145,833	(105,002)	0	5,884,524	5,864,109	5.62	324,241
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	211,671	50,000	(12,301)	0	249,370	230,521	11.21	23,093
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	14,016,581	0	(385,092)	0	13,631,489	13,824,035	20.83	2,855,714
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	5,446,944	0	(49,440)	0	5,397,504	5,422,224	8.95	483,966
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	44,342,195	0	(365,170)	0	43,977,025	44,159,610	6.60	2,905,940
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	4,647,964	21,433	(2,143)	0	4,667,254	4,657,609	8.39	390,841
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	50,841,189	11,550,736	(1,155,074)	0	61,236,851	56,039,020	10.13	5,357,281
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	7,595,119	35,023	(3,502)	0	7,626,640	7,610,880	7.93	603,047
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	11,013,953	50,788	(5,079)	0	11,059,662	11,036,808	7.93	874,853
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	2,932,322	13,522	(1,352)	0	2,944,492	2,938,407	6.18	181,638
393	STORES EQUIPMENT	15,838	0	0	0	15,838	15,838	4.99	791
394	TOOLS, SHOP AND GARAGE EQUIPMENT	45,410,964	2,373,995	(1,526,210)	0	46,258,749	45,834,857	5.14	2,312,041
395	LABORATORY EQUIPMENT	437,779	0	0	0	437,779	437,779	5.13	22,439
396	POWER OPERATED EQUIPMENT	13,798,162	0	0	0	13,798,162	13,798,162	6.38	880,798
397	COMMUNICATION EQUIPMENT	3,095,450	0	(731,313)	0	2,364,137	2,729,794	10.48	264,898
398	MISCELLANEOUS EQUIPMENT	1,936,970	507,168	(124,185)	0	2,319,953	2,128,462	3.18	60,593
399	OTHER TANGIBLE PROPERTY	-	0	0	0	0	0	-	0
TOTAL GENERAL PLANT		**386,618,216**	**31,373,882**	**(5,265,157)**	**0**	**412,726,941**	**399,672,579**		**24,703,132**
TOTAL DEPRECIABLE GAS PLANT		**5,908,417,996**	**495,796,098**	**(39,185,788)**	**0**	**6,365,028,306**	**6,136,723,151**		**143,679,849**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2027

ACCOUNT		BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
NONDEPRECIABLE PLANT									
301	ORGANIZATION	166,478	0	0	0	166,478	166,478		
302	FRANCHISES AND CONSENTS	193,597	0	0	0	193,597	193,597		
303	MISCELLANEOUS INTANGIBLE PLANT	289,868	0	0	0	289,868	289,868		
365.1	LAND	47,323	0	0	0	47,323	47,323		
374.1	LAND AND LAND RIGHTS - LAND	803,858	0	0	0	803,858	803,858		
374.2	LAND AND LAND RIGHTS - LAND RIGHTS	7,459,999	0	0	0	7,459,999	7,459,999		
389.1	LAND AND LAND RIGHTS - LAND	7,936,470	0	0	0	7,936,470	7,936,470		
389.2	LAND AND LAND RIGHTS - LAND RIGHTS	1,313	0	0	0	1,313	1,313		
TOTAL NONDEPRECIABLE PLANT		**16,898,906**	**0**	**0**	**0**	**16,898,906**	**16,898,906**		
TOTAL GAS PLANT		**5,925,316,902**	**495,796,098**	**(39,185,788)**	**0**	**6,381,927,212**	**6,153,622,057**		
OTHER UTILITY PLANT									
COMMON PLANT									
301	ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964	138,964		
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108	6,947,108		
390.1	STRUCTURES AND IMPROVEMENTS								
	UGI HEADQUARTERS BUILDING - DENVER	35,116,171	178,631	0	0	35,294,802	35,205,487	2.55	895,819
	READING DATA CENTER	20,414,469	0	0	0	20,414,469	20,414,469	2.84	580,484
	KNITTING MILLS OFFICE	1,382,240	0	0	0	1,382,240	1,382,240	3.94	54,514
	TOTAL ACCOUNT 390.1	*56,912,880*	*178,631*	*0*	*0*	*57,091,511*	*57,002,196*		*1,530,817*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,926,544	50,000	0	0	4,976,544	4,951,544	5.12	252,517
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	0	0	0	0	0	0	20.00	0
TOTAL COMMON PLANT		**68,925,496**	**228,631**	**0**	**0**	**69,154,127**	**69,039,812**		**1,783,334**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%		**61,419,509**	**203,733**	**0**	**0**	**61,623,243**	**61,521,376**		**1,589,129**
INFORMATION SERVICES (IS)									
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	17,877,324	0	0	0	17,877,324	17,877,324	19.49	3,483,451
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
	SUCCESS FACTORS	2,803,866	0	0	0	2,803,866	2,803,866	-	0
	UNITE ERP	10,695,816	0	0	0	10,695,816	10,695,816	7.14	764,025
	TOTAL ACCOUNT 391.2	13,499,682	0	0	0	13,499,682	13,499,682		764,025
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	98,427,853	13,886,116	(1,300,552)	0	111,013,417	104,720,635	9.89	9,881,444
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	134,033,083	299,691	(36,121)	0	134,296,653	134,164,868	6.82	9,139,001
TOTAL INFORMATION SERVICES		**263,837,942**	**14,185,807**	**(1,336,673)**	**0**	**276,687,076**	**270,262,509**		**23,267,921**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%		**223,787,342**	**12,032,402**	**(1,133,766)**	**0**	**234,685,978**	**229,236,660**		**19,735,851**
EMPIRE YARD BUILDING									
390.1	STRUCTURES AND IMPROVEMENTS	12,568,452	293,193	(29,319)	0	12,832,326	12,700,389	1.50	189,490
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%		**1,642,697**	**38,320**	**(3,832)**	**0**	**1,677,185**	**1,659,941**		**24,766**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION		**283,564,154**	**12,197,815**	**(1,129,934)**	**0**	**294,632,036**	**289,098,095**		**21,300,214**
TOTAL PLANT IN SERVICE		**6,208,881,056**	**507,993,913**	**(40,315,722)**	**0**	**6,676,559,248**	**6,442,720,152**		**164,980,063**

* TOTAL ACCRUALS SHOWN ARE BASED ON EACH DISTRICT'S AVERAGE BALANCES

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	2026 GROSS SALVAGE	2026 COST OF REMOVAL	2027 GROSS SALVAGE	2027 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	0	0	0	0	0	0	0	0	0	0	0	0
329	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
335	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	412	0	5,801	0	9,571	0	0	0	0	15,783	3,157
369	0	231	0	0	0	0	0	0	0	0	231	46
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**643**	**0**	**5,801**	**0**	**9,571**	**0**	**0**	**0**	**0**	**16,015**	**3,203**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	1,876	0	0	0	12,062	0	7,250	0	0	21,188	4,238
376.1	0	1,693,882	0	1,190,708	0	2,102,595	0	1,182,058	0	1,347,247	7,516,489	1,503,298
376.2	0	633,299	0	682,408	0	899,144	0	0	0	0	2,214,850	442,970
376.3	0	311,402	0	819,607	0	508,772	0	757,435	0	871,163	3,268,380	653,675
376.5	0	0	0	0	0	0	0	0	0	0	0	0
378	0	206,792	0	165,132	0	313,281	0	53,422	0	73,779	812,406	162,481
379	0	85,312	0	43,038	0	196,338	0	0	0	0	324,688	64,937
380	0	5,345,562	0	4,613,724	0	5,022,669	0	7,271,310	0	8,658,033	30,911,298	6,182,260
381	0	35,495	0	48,411	0	74,865	0	0	0	0	158,771	31,754
381.1	0	2,076	0	9,685	0	18,782	0	0	0	0	30,543	6,109
382	0	117,424	0	65,380	0	94,530	0	341,280	0	396,838	1,015,452	203,090
383	0	806	0	3,328,107	0	1,028,703	0	0	0	0	4,357,616	871,523
384	0	82	0	282	0	2,578	0	0	0	0	2,942	588
385	0	0	0	984	0	87,207	0	(326,138)	0	(402,567)	(640,513)	(128,103)
386.0	0	0	0	0	0	774	0	0	0	0	774	155
386.1	0	0	0	208	0	1,025	0	0	0	0	1,233	247
386.2	0	0	0	0	0	0	0	0	0	0	0	0
386.3	0	0	0	0	0	0	0	0	0	0	0	0
387	0	0	0	0	0	0	0	0	0	0	0	0
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**8,434,009**	**0**	**10,967,674**	**0**	**10,363,326**	**0**	**9,286,617**	**0**	**10,944,493**	**49,996,118**	**9,999,222**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	2026 GROSS SALVAGE	2026 COST OF REMOVAL	2027 GROSS SALVAGE	2027 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	395	0	552,200	0	105,144	0	30,951	0	71,697	760,386	152,077
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	(4,547)	0	(214)	0	(4,761)	(952)
392.2	(887,270)	0	(645,657)	0	(749,272)	0	(86,856)	0	(115,507)	0	(2,484,563)	(496,912)
392.3	0	0	0	0	0	0	(7,430)	0	(350)	0	(7,780)	(1,556)
392.4	0	0	0	0	0	0	(10,774)	0	(508)	0	(11,282)	(2,257)
392.5	0	0	0	0	0	0	(2,869)	0	(135)	0	(3,004)	(601)
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	167	0	0	0	0	0	0	0	0	167	33
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	11	0	2,889	0	9,703	0	0	0	0	12,603	2,520
398	0	79,441	0	74,236	0	86,622	0	0	0	0	240,299	48,060
TOTAL	**(887,270)**	**80,015**	**(645,657)**	**629,324**	**(749,272)**	**201,469**	**(112,476)**	**30,951**	**(116,715)**	**71,697**	**(1,497,935)**	**(299,588)**
TOTAL GAS PLANT	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**(112,476)**	**9,317,568**	**(116,715)**	**11,016,190**	**48,514,198**	**9,702,837**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**(112,476)**	**9,317,568**	**(116,715)**	**11,016,190**	**48,514,198**	**9,702,837**

* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1900	71,114	71,114			0.0
1901	3,919	3,749	170	170	0.0
1902	32,146	32,080	66	236	0.0
1903	42,279	42,036	243	479	0.0
1904	13,568	12,908	660	1,139	0.0
1905	7,041	6,726	315	1,454	0.0
1906	17,522	16,877	645	2,099	0.0
1907	22,133	21,336	797	2,896	0.0
1908	29,989	28,259	1,730	4,626	0.0
1909	9,220	8,531	689	5,315	0.0
1910	19,807	18,704	1,103	6,418	0.0
1911	36,803	34,670	2,133	8,551	0.0
1912	24,366	22,758	1,608	10,159	0.0
1913	24,750	22,358	2,392	12,551	0.0
1914	56,148	50,077	6,071	18,622	0.0
1915	32,913	29,672	3,241	21,863	0.0
1916	22,269	19,901	2,368	24,231	0.0
1917	11,501	11,027	474	24,705	0.0
1918	10,455	9,944	511	25,216	0.0
1919	14,391	13,723	668	25,884	0.0
1920	14,768	14,057	711	26,595	0.0
1921	61,621	57,123	4,498	31,093	0.0
1922	76,456	72,202	4,254	35,347	0.0
1923	55,657	50,308	5,349	40,696	0.0
1924	268,447	245,914	22,533	63,229	0.0
1925	71,476	65,071	6,405	69,634	0.0
1926	345,039	306,445	38,594	108,228	0.0
1927	99,115	92,978	6,137	114,365	0.0
1928	186,204	169,957	16,247	130,612	0.0
1929	179,884	161,549	18,335	148,947	0.0
1930	372,241	319,970	52,271	201,218	0.0
1931	390,640	341,909	48,731	249,949	0.0
1932	149,617	146,396	3,221	253,170	0.0
1933	27,280	24,884	2,396	255,566	0.0
1934	24,263	22,443	1,820	257,386	0.0
1935	17,179	15,692	1,487	258,873	0.0
1936	42,035	38,852	3,183	262,056	0.0
1937	25,095	22,886	2,209	264,265	0.0
1938	14,953	13,289	1,664	265,929	0.0
1939	30,398	27,065	3,333	269,262	0.0
1940	49,981	45,191	4,790	274,052	0.0
1941	73,286	65,050	8,236	282,288	0.0
1942	35,702	30,127	5,575	287,863	0.0
1943	20,036	19,030	1,006	288,869	0.0
1944	16,183	14,372	1,811	290,680	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1945	26,007	23,845	2,162	292,842	0.0
1946	456,047	367,951	88,096	380,938	0.0
1947	131,362	113,888	17,474	398,412	0.0
1948	265,303	234,451	30,852	429,264	0.0
1949	439,751	393,712	46,039	475,303	0.0
1950	1,971,093	1,577,838	393,255	868,558	0.0
1951	738,406	629,909	108,497	977,055	0.0
1952	2,183,030	1,918,748	264,282	1,241,337	0.0
1953	1,425,890	1,142,880	283,010	1,524,347	0.0
1954	2,536,895	2,066,032	470,863	1,995,210	0.0
1955	2,291,746	1,908,230	383,516	2,378,726	0.0
1956	4,185,378	3,379,831	805,547	3,184,273	0.1
1957	3,705,167	2,812,290	892,877	4,077,150	0.1
1958	3,690,902	2,728,924	961,978	5,039,128	0.1
1959	3,833,516	2,905,915	927,601	5,966,729	0.1
1960	4,797,927	3,607,076	1,190,851	7,157,580	0.2
1961	4,132,403	3,139,211	993,192	8,150,772	0.2
1962	3,992,783	2,965,156	1,027,627	9,178,399	0.2
1963	5,327,590	3,851,088	1,476,502	10,654,901	0.2
1964	6,824,656	4,905,422	1,919,234	12,574,135	0.3
1965	7,433,645	5,403,817	2,029,828	14,603,963	0.3
1966	8,217,426	5,997,187	2,220,239	16,824,202	0.4
1967	7,699,930	5,497,461	2,202,469	19,026,671	0.4
1968	10,032,137	7,080,822	2,951,315	21,977,986	0.5
1969	10,726,750	7,549,368	3,177,382	25,155,368	0.5
1970	9,835,505	6,950,678	2,884,827	28,040,195	0.6
1971	8,952,702	6,269,688	2,683,014	30,723,209	0.6
1972	10,393,864	7,129,819	3,264,045	33,987,254	0.7
1973	8,470,705	5,866,621	2,604,084	36,591,338	0.8
1974	9,911,953	7,145,383	2,766,570	39,357,908	0.8
1975	8,026,454	5,507,702	2,518,752	41,876,660	0.9
1976	7,752,960	5,378,844	2,374,116	44,250,776	0.9
1977	9,781,227	6,611,333	3,169,894	47,420,670	1.0
1978	9,434,527	6,205,461	3,229,066	50,649,736	1.1
1979	14,275,335	9,241,936	5,033,399	55,683,135	1.2
1980	24,001,660	15,577,341	8,424,319	64,107,454	1.3
1981	24,821,421	15,941,341	8,880,080	72,987,534	1.5
1982	24,528,969	16,435,961	8,093,008	81,080,542	1.7
1983	12,661,944	8,749,779	3,912,165	84,992,707	1.8
1984	17,274,459	11,700,538	5,573,921	90,566,628	1.9
1985	20,926,803	14,159,937	6,766,866	97,333,494	2.0
1986	25,580,935	16,712,389	8,868,546	106,202,040	2.2
1987	28,529,424	18,584,650	9,944,774	116,146,814	2.4
1988	40,806,136	25,771,100	15,035,036	131,181,850	2.8
1989	43,806,736	27,395,727	16,411,009	147,592,859	3.1

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1990	47,488,934	29,380,018	18,108,916	165,701,775	3.5
1991	38,565,077	23,609,447	14,955,630	180,657,405	3.8
1992	41,475,224	25,432,521	16,042,703	196,700,108	4.1
1993	31,774,205	19,288,055	12,486,150	209,186,258	4.4
1994	48,552,223	28,899,589	19,652,634	228,838,892	4.8
1995	56,898,906	31,488,799	25,410,107	254,248,999	5.3
1996	60,448,466	32,392,009	28,056,457	282,305,456	5.9
1997	73,845,267	39,629,015	34,216,252	316,521,708	6.7
1998	57,617,998	30,236,414	27,381,584	343,903,292	7.2
1999	44,088,017	22,748,121	21,339,896	365,243,188	7.7
2000	60,871,942	30,087,401	30,784,541	396,027,729	8.3
2001	56,279,630	27,255,858	29,023,772	425,051,501	8.9
2002	55,353,934	27,116,348	28,237,586	453,289,087	9.5
2003	55,770,054	25,762,721	30,007,333	483,296,420	10.2
2004	72,461,582	33,513,196	38,948,386	522,244,806	11.0
2005	64,576,218	27,690,060	36,886,158	559,130,964	11.7
2006	62,872,918	26,813,029	36,059,889	595,190,853	12.5
2007	63,227,377	26,540,831	36,686,546	631,877,399	13.3
2008	66,716,157	27,419,054	39,297,103	671,174,502	14.1
2009	65,117,987	25,108,078	40,009,909	711,184,411	14.9
2010	57,941,463	21,132,500	36,808,963	747,993,374	15.7
2011	86,023,492	29,758,882	56,264,610	804,257,984	16.9
2012	106,057,733	34,722,186	71,335,547	875,593,531	18.4
2013	121,420,863	36,972,383	84,448,480	960,042,011	20.2
2014	155,314,107	44,396,396	110,917,711	1,070,959,722	22.5
2015	179,480,485	47,188,676	132,291,809	1,203,251,531	25.3
2016	198,757,522	48,239,999	150,517,523	1,353,769,054	28.4
2017	201,191,850	44,471,416	156,720,434	1,510,489,488	31.7
2018	289,435,349	59,257,242	230,178,107	1,740,667,595	36.6
2019	264,249,189	53,477,278	210,771,911	1,951,439,506	41.0
2020	267,832,909	51,841,425	215,991,484	2,167,430,990	45.5
2021	352,438,530	55,064,261	297,374,269	2,464,805,259	51.8
2022	413,771,169	57,750,452	356,020,717	2,820,825,976	59.3
2023	481,021,958	66,330,307	414,691,651	3,235,517,627	68.0
2024	339,207,440	32,136,900	307,070,540	3,542,588,167	74.4
2025	341,199,806	25,073,408	316,126,398	3,858,714,565	81.1
2026	430,113,359	18,693,647	411,419,712	4,270,134,277	89.7
2027	495,579,613	6,798,106	488,781,507	4,758,915,784	100.0
TOTAL	6,365,028,302	1,606,112,518	4,758,915,784		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2019	33,513,297	8,207,882	25,305,415	25,305,415	50.7
2020	1,957,793	407,117	1,550,676	26,856,091	53.8
2021	658,288	121,856	536,432	27,392,523	54.9
2022	4,218,639	856,607	3,362,032	30,754,555	61.6
2023	11,849,883	1,553,060	10,296,823	41,051,378	82.3
2024	8,704,747	926,670	7,778,077	48,829,455	97.8
2025	532,025	61,743	470,282	49,299,737	98.8
2026	404,752	22,670	382,082	49,681,819	99.6
2027	228,631	4,899	223,732	49,905,551	100.0
TOTAL	62,068,055	12,162,504	49,905,551		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2016	1,957,869	1,482,676	475,193	475,193	0.4
2017	75,949,954	52,514,550	23,435,404	23,910,597	17.7
2018	3,434,311	3,124,288	310,023	24,220,620	18.0
2019	62,692,655	37,212,910	25,479,745	49,700,365	36.9
2020	12,128,665	8,853,641	3,275,024	52,975,389	39.3
2021	14,361,667	7,650,808	6,710,859	59,686,248	44.3
2022	9,534,377	4,835,842	4,698,535	64,384,783	47.7
2023	14,211,435	9,095,373	5,116,062	69,500,845	51.5
2024	10,659,528	5,803,425	4,856,103	74,356,948	55.1
2025	9,387,744	3,518,291	5,869,453	80,226,401	59.5
2026	48,214,614	7,039,106	41,175,508	121,401,909	90.0
2027	14,154,256	684,100	13,470,156	134,872,065	100.0
TOTAL	276,687,075	141,815,010	134,872,065		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1902	3,610.27	3,610	3,610			
1903	4,110.54	4,111	4,111			
1908	44.05	44	44			
1910	85.13	85	85			
1912	835.22	835	835			
1913	222.36	222	222			
1914	14.50	14	15			
1915	224.10	224	224			
1916	117.50	118	118			
1917	64.30	64	64			
1926	6,471.58	6,366	6,472			
1929	1,806.23	1,760	1,806			
1930	2,041.31	1,983	2,041			
1931	27,123.22	26,259	27,062	61	2.23	27
1932	2,640.53	2,547	2,625	16	2.47	6
1933	538.99	518	534	5	2.70	2
1934	812.94	779	803	10	2.95	3
1935	12.64	12	12			
1937	203.24	192	198	5	3.71	1
1938	375.47	354	365	11	3.96	3
1939	962.92	905	933	30	4.22	7
1940	6,450.60	6,037	6,222	229	4.49	51
1941	592.71	552	569	24	4.75	5
1942	337.44	313	323	15	5.02	3
1943	60.01	55	57	3	5.30	1
1944	422.25	389	401	21	5.58	4
1945	631.09	578	596	35	5.86	6
1946	3,351.10	3,057	3,150	201	6.15	33
1947	2,508.33	2,278	2,348	161	6.44	25
1948	4,635.54	4,189	4,317	318	6.75	47
1949	1,157.34	1,040	1,072	86	7.07	12
1950	190.65	171	176	14	7.39	2
1951	4,042.41	3,596	3,706	336	7.73	43
1952	198.20	175	180	18	8.09	2
1953	5,400.53	4,748	4,893	507	8.46	60
1954	14,353.89	12,539	12,922	1,432	8.85	162
1955	8,390.67	7,282	7,505	886	9.25	96
1956	78,471.52	67,620	69,687	8,784	9.68	907
1957	2,231.51	1,909	1,967	264	10.13	26
1958	3,854.85	3,271	3,371	484	10.60	46
1959	3,405.26	2,865	2,953	453	11.10	41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	11,197.19	9,340	9,626	1,572	11.61	135
1961	2,660.99	2,199	2,266	395	12.15	33
1962	3,222.41	2,637	2,718	505	12.72	40
1963	3,157.03	2,557	2,635	522	13.30	39
1964	5,365.41	4,299	4,430	935	13.91	67
1965	6,572.95	5,208	5,367	1,206	14.54	83
1966	36,334.10	28,455	29,325	7,009	15.18	462
1967	22,318.73	17,272	17,800	4,519	15.83	285
1968	3,796.90	2,902	2,991	806	16.50	49
1969	12,470.57	9,410	9,698	2,773	17.18	161
1970	18,015.96	13,417	13,827	4,189	17.87	234
1971	1,199.64	881	908	292	18.57	16
1972	11,935.28	8,648	8,912	3,023	19.28	157
1973	5,080.37	3,629	3,740	1,340	20.00	67
1974	8,346.12	5,876	6,056	2,290	20.72	111
1975	11,480.98	7,961	8,204	3,277	21.46	153
1976	7,995.15	5,458	5,625	2,370	22.21	107
1977	11,905.30	7,997	8,241	3,664	22.98	159
1978	12,918.41	8,535	8,796	4,122	23.75	174
1979	7,570.24	4,917	5,067	2,503	24.53	102
1980	4,856.13	3,100	3,195	1,661	25.32	66
1981	73,749.17	46,219	47,632	26,117	26.13	1,000
1982	10,050.64	6,504	6,703	3,348	24.68	136
1983	9,041.47	5,721	5,896	3,146	25.68	123
1984	15,250.78	9,498	9,788	5,462	26.19	209
1985	26,754.50	16,277	16,775	9,980	27.19	367
1986	14,112.19	8,441	8,699	5,413	27.72	195
1987	3,342.10	1,950	2,010	1,332	28.72	46
1988	11,301.63	6,432	6,629	4,673	29.72	157
1989	1,090.00	609	628	462	30.25	15
1990	8,000.14	4,350	4,483	3,517	31.25	113
1991	117,309.04	62,514	64,425	52,884	31.78	1,664
1992	25,030.74	12,971	13,368	11,663	32.78	356
1993	12,460.42	6,274	6,466	5,995	33.78	177
1994	6,889.97	3,391	3,495	3,395	34.32	99
1995	12,673.77	6,049	6,234	6,440	35.32	182
1996	12,902.15	5,967	6,149	6,753	36.32	186
1997	66,170.17	29,823	30,735	35,435	36.87	961
1998	16,023.55	6,983	7,196	8,827	37.87	233
1999	3,898.06	1,641	1,691	2,207	38.87	57
2000	5,089.04	2,066	2,129	2,960	39.87	74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2001	2,659.41	1,040	1,072	1,588	40.87	39
2002	551.45	209	215	336	41.41	8
2003	1,306.89	475	490	817	42.41	19
2004	373.65	130	134	240	43.41	6
2007	10,611.38	3,224	3,323	7,289	46.41	157
2024	114.45	6	6	108	62.29	2
	868,159.56	577,128	594,389	273,771		10,902

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.1 1.26

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
1915	44.03	44	44			
1931	22.41	22	22			
1936	428.90	429	429			
1939	2,662.19	2,662	2,662			
1940	342.66	343	343			
1946	195.14	195	195			
1953	97.16	97	97			
1954	398.72	399	399			
1955	1,082.26	1,082	1,082			
1956	2,295.78	2,296	2,296			
1957	310.18	310	310			
1958	2,058.46	2,058	2,058			
1959	300.33	300	300			
1960	6,541.37	6,541	6,541			
1961	4,353.35	4,353	4,353			
1962	2,282.71	2,283	2,283			
1963	736.08	736	736			
1964	190.55	191	191			
1965	2,343.06	2,343	2,343			
1966	2,250.24	2,250	2,250			
1967	9,977.71	9,971	9,978			
1968	2,151.32	2,126	2,151			
1969	544.69	532	545			
1970	40.03	39	40			
1971	1,214.19	1,160	1,214			
1973	700.59	654	701			
1974	4,750.87	4,388	4,751			
1977	193.66	173	194			
1978	2,207.46	1,951	2,207			
1979	2,203.60	1,924	2,204			
1983	5,281.99	4,768	5,282			
1984	369.17	331	369			
1985	9,821.44	8,672	9,821			
1986	241.46	211	241			
1987	1,014.54	878	1,015			
1988	31,015.80	26,661	31,016			
1989	44,844.88	38,082	44,845			
1994	601.90	478	602			
1996	1,215.58	935	1,216			
1998	1,575.63	1,171	1,576			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	1,142	1,760			
2019	11,416.29	3,619	6,529	4,888	18.31	267
2020	138.01	40	72	66	18.47	4
	162,216.47	138,840	157,263	4,953		271

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.3 0.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1900	71,113.66	68,118	71,114			
1902	24,056.23	22,863	24,056			
1903	33,197.34	31,436	33,197			
1904	1,964.62	1,853	1,965			
1906	2,420.69	2,267	2,421			
1907	8,730.25	8,148	8,730			
1910	749.15	692	749			
1913	1,738.46	1,592	1,738			
1915	63.32	58	63			
1922	35.55	32	36			
1925	1,356.81	1,193	1,357			
1926	46,464.38	40,709	46,464			
1927	2,171.63	1,896	2,172			
1928	180.25	157	180			
1929	27,529.19	23,848	27,529			
1930	2,522.76	2,177	2,523			
1931	296.56	255	297			
1932	122,819.26	105,133	122,819			
1933	4,897.35	4,175	4,897			
1934	10,855.44	9,213	10,855			
1935	1,410.95	1,192	1,411			
1936	16,622.35	13,981	16,622			
1937	2,388.88	2,000	2,389			
1938	2,797.65	2,331	2,798			
1939	797.65	661	798			
1940	11,364.66	9,372	11,365			
1941	11,633.51	9,543	11,634			
1942	1,215.69	992	1,214	1	13.82	
1943	5,838.88	4,736	5,797	42	14.17	3
1944	48.34	39	48	1	14.53	
1945	1,498.10	1,200	1,469	29	14.90	2
1946	4,905.03	3,906	4,781	124	15.28	8
1947	24,941.60	19,731	24,151	791	15.67	50
1948	98,837.20	77,647	95,040	3,797	16.08	236
1949	28,199.11	21,999	26,927	1,272	16.49	77
1950	2,735.68	2,119	2,594	142	16.92	8
1951	202,177.37	155,379	190,185	11,992	17.36	691
1952	22,207.66	16,934	20,727	1,480	17.81	83
1953	200,020.82	151,296	185,187	14,834	18.27	812
1954	797,823.90	598,472	732,534	65,290	18.74	3,484
1955	81,749.31	60,789	74,406	7,343	19.23	382

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1956	1,473,781.22	1,086,280	1,329,614	144,167	19.72	7,311
1957	311,182.44	227,247	278,152	33,031	20.23	1,633
1958	299,804.72	216,858	265,436	34,369	20.75	1,656
1959	613,382.04	439,347	537,764	75,618	21.28	3,553
1960	674,919.59	478,565	585,767	89,153	21.82	4,086
1961	47,891.52	33,601	41,128	6,764	22.38	302
1962	190,718.09	132,383	162,038	28,680	22.94	1,250
1963	122,060.87	83,798	102,569	19,492	23.51	829
1964	290,969.66	197,472	241,707	49,263	24.10	2,044
1965	701,420.51	470,513	575,911	125,509	24.69	5,083
1966	742,304.44	491,999	602,210	140,094	25.29	5,540
1967	215,827.53	141,266	172,911	42,917	25.91	1,656
1968	370,389.64	239,372	292,993	77,397	26.53	2,917
1969	640,487.71	408,548	500,065	140,422	27.16	5,170
1970	874,219.01	550,172	673,414	200,805	27.80	7,223
1971	453,818.02	281,671	344,767	109,051	28.45	3,833
1972	966,536.05	591,394	723,870	242,666	29.11	8,336
1973	372,161.96	224,388	274,652	97,510	29.78	3,274
1974	485,847.07	288,593	353,240	132,607	30.45	4,355
1975	297,092.08	173,739	212,658	84,434	31.14	2,711
1976	137,471.87	79,129	96,854	40,617	31.83	1,276
1977	134,299.99	76,068	93,108	41,192	32.52	1,267
1978	287,058.05	159,871	195,683	91,375	33.23	2,750
1979	501,981.46	274,820	336,382	165,600	33.94	4,879
1980	243,613.68	131,032	160,384	83,230	34.66	2,401
1981	283,711.51	149,837	183,401	100,310	35.39	2,834
1982	319,398.12	187,870	229,954	89,444	31.68	2,823
1983	524,887.81	301,915	369,546	155,342	32.68	4,753
1984	749,802.45	424,838	520,005	229,798	33.08	6,947
1985	455,843.70	254,224	311,172	144,672	33.51	4,317
1986	565,064.08	307,677	376,599	188,465	34.51	5,461
1987	414,536.27	221,901	271,608	142,928	34.94	4,091
1988	491,903.15	258,741	316,701	175,202	35.37	4,953
1989	207,476.32	106,352	130,176	77,301	36.37	2,125
1990	360,151.18	181,120	221,692	138,459	36.82	3,760
1991	2,298,208.76	1,133,017	1,386,820	911,388	37.28	24,447
1992	1,177,930.89	564,700	691,197	486,734	38.28	12,715
1993	1,136,543.85	533,266	652,721	483,823	38.74	12,489
1994	971,986.45	445,947	545,842	426,144	39.22	10,865
1995	571,362.11	254,256	311,211	260,151	40.22	6,468
1996	804,324.21	349,398	427,665	376,659	40.69	9,257

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1997	1,997,584.37	845,977	1,035,481	962,103	41.18	23,363
1998	1,718,962.57	703,915	861,597	857,366	42.18	20,326
1999	1,080,765.90	430,469	526,897	553,869	42.67	12,980
2000	2,093,639.95	810,239	991,738	1,101,902	43.17	25,525
2001	940,486.78	353,059	432,147	508,340	43.68	11,638
2002	1,450,386.34	523,735	641,055	809,331	44.68	18,114
2003	537,154.95	187,575	229,593	307,562	45.19	6,806
2004	239,158.46	80,620	98,679	140,479	45.72	3,073
2005	237,738.75	76,695	93,875	143,864	46.72	3,079
2006	169,927.36	52,711	64,519	105,409	47.25	2,231
2007	509,991.81	151,825	185,835	324,157	47.78	6,784
2008	103,422.99	29,641	36,281	67,142	48.53	1,384
2009	74,105.67	20,290	24,835	49,271	49.07	1,004
2010	158,384.81	41,307	50,560	107,825	49.61	2,173
2011	140,623.77	34,804	42,600	98,023	50.17	1,954
2012	2,357,530.59	551,662	675,238	1,682,293	50.73	33,162
2013	41,989.81	9,196	11,256	30,734	51.72	594
2024	307,730.46	17,787	21,771	285,959	57.10	5,008
2025	643,848.72	27,042	33,100	610,749	57.02	10,711
	39,468,181.38	19,581,868	23,931,881	15,536,300		399,385

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.9 1.01

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1927	43.41	43	43			
1935	1.00	1	1			
1937	63.36	63	63			
1938	130.20	129	130			
1939	199.99	197	200			
1940	188.95	185	189			
1942	115.52	112	116			
1943	207.70	200	208			
1944	83.77	80	84			
1945	174.42	166	174			
1946	163.63	155	164			
1947	277.29	261	277			
1948	89.09	83	89			
1950	7.97	7	8			
1952	18.79	17	19			
1953	5,944.35	5,431	5,944			
1954	8,508.82	7,738	8,509			
1955	7,542.08	6,825	7,542			
1956	39,702.37	35,740	39,702			
1957	13,574.54	12,159	13,575			
1958	6,469.06	5,764	6,469			
1959	9,801.88	8,688	9,802			
1960	24,067.26	21,214	24,067			
1961	5,498.45	4,821	5,498			
1962	12,455.03	10,856	12,406	49	6.29	8
1963	5,203.12	4,509	5,153	50	6.54	8
1964	19,172.75	16,516	18,874	299	6.79	44
1965	16,408.17	14,047	16,053	356	7.05	50
1966	43,116.46	36,675	41,911	1,205	7.32	165
1967	18,626.28	15,737	17,984	642	7.60	84
1968	18,055.59	15,148	17,311	745	7.89	94
1969	32,278.33	26,883	30,721	1,557	8.19	190
1970	15,250.12	12,602	14,401	849	8.51	100
1971	26,308.31	21,562	24,640	1,668	8.84	189
1972	26,694.33	21,693	24,790	1,904	9.18	207
1973	12,036.90	9,693	11,077	960	9.54	101
1974	18,632.52	14,860	16,982	1,651	9.92	166
1975	30,467.80	24,057	27,492	2,976	10.31	289
1976	138,678.97	108,339	123,807	14,872	10.72	1,387
1977	14,832.80	11,458	13,094	1,739	11.15	156
1978	22,161.07	16,919	19,335	2,826	11.59	244

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1979	41,008.38	30,915	35,329	5,680	12.06	471
1980	13,577.55	10,103	11,545	2,032	12.54	162
1981	82,437.31	60,499	69,137	13,301	13.04	1,020
1982	156,832.69	123,490	141,121	15,712	12.22	1,286
1983	24,048.18	18,623	21,282	2,766	12.89	215
1984	50,677.87	38,794	44,333	6,345	13.25	479
1985	86,879.75	65,707	75,088	11,792	13.61	866
1986	86,985.91	64,587	73,808	13,178	14.31	921
1987	52,185.49	38,231	43,689	8,496	14.69	578
1988	411,643.09	297,289	339,734	71,909	15.10	4,762
1989	41,658.60	29,478	33,687	7,972	15.81	504
1990	297,917.74	207,529	237,159	60,759	16.22	3,746
1991	147,610.27	100,596	114,958	32,652	16.94	1,928
1992	264,883.76	177,419	202,750	62,134	17.38	3,575
1993	163,266.69	106,809	122,059	41,208	18.10	2,277
1994	349,935.44	224,554	256,614	93,321	18.56	5,028
1995	117,235.62	73,729	84,256	32,980	19.03	1,733
1996	215,121.50	131,762	150,574	64,547	19.77	3,265
1997	728,580.35	436,420	498,729	229,851	20.25	11,351
1998	560,594.04	326,322	372,912	187,682	21.00	8,937
1999	16,725.51	9,497	10,853	5,873	21.50	273
2000	174,732.10	96,173	109,904	64,828	22.26	2,912
2001	495,273.00	265,219	303,085	192,188	22.77	8,440
2002	154,135.03	79,780	91,170	62,965	23.53	2,676
2003	301,200.83	151,203	172,791	128,410	24.06	5,337
2004	59,852.58	28,945	33,078	26,775	24.83	1,078
2005	86,161.34	40,255	46,002	40,159	25.37	1,583
2006	82,235.60	37,047	42,336	39,899	25.92	1,539
2007	11,729.27	5,059	5,781	5,948	26.70	223
2008	249,781.89	104,234	119,116	130,666	27.23	4,799
2012	21,662.45	7,422	8,482	13,181	29.75	443
2013	8,571.24	2,772	3,168	5,403	30.34	178
2021	1,310.54	203	232	1,079	35.52	30
2022	23,129.77	3,067	3,505	19,625	35.99	545
	6,172,833.83	3,885,365	4,437,172	1,735,662		86,642

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.0 1.40

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1955	5,466.25	5,466	5,466			
1965	7,727.57	7,728	7,728			
1966	1,743.15	1,743	1,743			
1967	249.76	250	250			
1968	2,500.34	2,500	2,500			
1972	1,946.45	1,946	1,946			
1979	706.12	706	706			
1982	5,572.11	5,547	5,572			
1983	1,354.71	1,331	1,355			
1984	2,338.50	2,276	2,339			
1985	8,363.40	8,021	8,363			
1986	1,865.01	1,770	1,865			
1987	8,236.27	7,757	8,236			
1988	56,812.32	52,847	56,812			
1989	6,202.17	5,694	6,202			
1990	81,477.96	74,055	81,478			
1991	19,398.63	17,439	19,399			
1992	11,826.34	10,505	11,826			
1993	4,988.84	4,374	4,989			
1994	24,237.82	20,954	24,238			
1995	53,971.10	46,124	53,971			
1996	2,814.71	2,375	2,815			
1997	270.53	224	271			
2000	83,012.05	65,596	80,982	2,030	7.23	281
2001	21,876.59	16,941	20,915	962	7.65	126
2004	19,336.59	14,071	17,372	1,965	8.70	226
2009	679,443.48	434,912	536,926	142,518	10.40	13,704
2010	158,522.71	98,205	121,240	37,283	10.75	3,468
2011	574,467.00	343,129	423,614	150,853	11.12	13,566
2012	649,682.90	372,593	459,989	189,694	11.53	16,452
2013	552,258.31	304,294	375,670	176,589	11.82	14,940
2014	229,452.61	120,509	148,776	80,677	12.21	6,607
2015	208,014.12	104,007	128,403	79,611	12.50	6,369
2022	19,067.98	5,411	6,680	12,388	13.88	893
	3,505,204.40	2,161,300	2,630,636	874,568		76,632

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.4 2.19

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1931	73.41	73	73			
1932	22.79	23	23			
1934	159.65	160	160			
1935	148.67	149	149			
1937	75.60	76	76			
1938	348.00	348	348			
1952	193.45	193	193			
1956	802.14	802	802			
1958	54.05	54	54			
1959	1,630.62	1,631	1,631			
1962	268.78	269	269			
1964	542.39	535	542			
1965	237.71	233	238			
1966	1,610.42	1,566	1,610			
1967	1,046.31	1,009	1,046			
1968	8,185.23	7,832	8,185			
1969	1,294.81	1,229	1,295			
1970	2,302.48	2,168	2,302			
1971	4,402.26	4,113	4,402			
1972	6,378.34	5,917	6,378			
1973	2,116.13	1,949	2,116			
1974	772.96	707	773			
1975	728.51	662	729			
1976	666.84	602	667			
1977	2,372.22	2,126	2,372			
1978	395.78	352	393	3	3.86	1
1979	1,489.70	1,315	1,469	21	4.10	5
1980	1,156.83	1,013	1,132	25	4.34	6
1981	1,410.00	1,225	1,368	42	4.58	9
1982	4,310.08	3,920	4,310			
1983	3,348.16	3,022	3,348			
1984	3,634.15	3,254	3,634			
1985	5,292.73	4,696	5,252	41	5.37	8
1986	1,466.52	1,295	1,448	18	5.48	3
1987	1,617.48	1,413	1,580	37	5.83	6
1988	7,215.84	6,231	6,969	247	6.20	40
1989	11,462.74	9,821	10,984	479	6.39	75
1990	14,888.28	12,590	14,080	808	6.80	119
1991	14,350.24	11,965	13,381	969	7.23	134
1992	10,561.54	8,711	9,742	819	7.49	109

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1993	9,905.10	8,040	8,992	913	7.95	115
1994	3,879.74	3,096	3,463	417	8.42	50
1995	7,818.56	6,152	6,880	938	8.73	107
	140,637.24	122,537	134,860	5,777		787
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.3	0.56

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1982	15,664.23	15,664	15,664			
1983	11,125.29	11,125	11,125			
1985	4,384.63	4,385	4,385			
1986	38,021.86	38,022	38,022			
1990	11,962.90	11,963	11,963			
1991	2,199.99	2,200	2,200			
1992	1,383.30	1,383	1,383			
1995	24,385.78	24,222	24,386			
1996	494.25	487	494			
2015	100,388.74	61,619	67,207	33,182	7.87	4,216
	210,010.97	171,070	176,829	33,182		4,216

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9 2.01

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1903	298.00	295	298			
1904	222.17	220	222			
1929	410.41	372	410			
1930	548.08	494	548			
1931	10,677.87	9,590	10,678			
1932	38.71	35	39			
1933	55.00	49	55			
1934	123.52	110	123	1	8.46	
1935	533.10	471	525	8	8.75	1
1936	100.54	88	98	2	9.04	
1937	223.29	195	217	6	9.34	1
1938	178.56	156	174	5	9.65	1
1939	285.78	248	276	9	9.96	1
1940	249.96	216	241	9	10.28	1
1941	57.82	50	56	2	10.62	
1942	19.44	17	19			
1944	36.92	31	35	2	11.68	
1945	59.80	50	56	4	12.05	
1946	160.11	134	149	11	12.44	1
1947	235.63	195	217	18	12.84	1
1948	51.03	42	47	4	13.25	
1949	2,077.70	1,699	1,894	184	13.67	13
1950	1,726.56	1,402	1,563	163	14.11	12
1951	360.18	290	323	37	14.55	3
1952	287.05	230	256	31	15.01	2
1953	1,145.40	909	1,013	132	15.49	9
1954	877.98	691	770	108	15.97	7
1955	3,133.21	2,445	2,726	407	16.47	25
1956	1,794.30	1,388	1,547	247	16.98	15
1957	5,277.55	4,045	4,510	768	17.51	44
1958	1,136.57	863	962	174	18.04	10
1959	1,431.64	1,077	1,201	231	18.59	12
1960	1,139.60	849	947	193	19.15	10
1961	1,739.80	1,282	1,429	311	19.72	16
1962	534.64	390	435	100	20.31	5
1963	1,024.78	739	824	201	20.91	10
1964	2,424.42	1,729	1,928	497	21.51	23
1965	1,904.74	1,343	1,497	407	22.13	18
1966	14,200.26	9,891	11,027	3,173	22.76	139
1967	36,083.66	24,826	27,678	8,406	23.40	359
1968	18,362.30	12,474	13,907	4,455	24.05	185

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1969	11,282.03	7,565	8,434	2,848	24.71	115
1970	6,080.40	4,023	4,485	1,595	25.38	63
1971	15,534.05	10,136	11,300	4,234	26.06	162
1972	18,498.57	11,901	13,268	5,230	26.75	196
1973	38,364.70	24,323	27,117	11,247	27.45	410
1974	49,272.90	30,772	34,307	14,966	28.16	531
1975	37,863.68	23,284	25,959	11,905	28.88	412
1976	13,898.67	8,413	9,379	4,519	29.60	153
1977	19,181.60	11,425	12,738	6,444	30.33	212
1978	24,833.70	14,543	16,214	8,620	31.08	277
1979	27,735.34	15,968	17,802	9,933	31.82	312
1980	38,526.40	21,791	24,294	14,232	32.58	437
1981	41,644.61	23,127	25,784	15,861	33.35	476
1982	29,660.39	17,716	19,751	9,909	30.51	325
1983	47,020.30	27,465	30,620	16,400	31.51	520
1984	51,245.11	29,476	32,862	18,383	31.94	576
1985	70,214.20	39,755	44,322	25,892	32.37	800
1986	74,675.20	41,280	46,022	28,653	33.37	859
1987	61,590.79	33,468	37,313	24,278	33.82	718
1988	64,488.00	34,172	38,098	26,390	34.82	758
1989	63,293.80	32,925	36,707	26,586	35.28	754
1990	76,971.45	38,994	43,474	33,498	36.28	923
1991	69,790.71	34,658	38,640	31,151	36.74	848
1992	74,877.76	36,421	40,605	34,273	37.22	921
1993	94,389.03	44,608	49,733	44,656	38.22	1,168
1994	63,758.76	29,469	32,854	30,904	38.69	799
1995	64,141.55	28,755	32,058	32,083	39.69	808
1996	101,676.17	44,483	49,593	52,083	40.18	1,296
1997	147,067.21	62,283	69,438	77,629	41.18	1,885
1998	219,807.88	90,649	101,063	118,745	41.67	2,850
1999	109,098.49	43,454	48,446	60,652	42.67	1,421
2000	148,695.59	57,545	64,156	84,540	43.17	1,958
2001	49,857.74	18,587	20,722	29,135	44.17	660
2002	51,469.65	18,586	20,721	30,748	44.68	688
2003	48,988.25	16,989	18,941	30,048	45.68	658
2004	503,472.20	168,562	187,927	315,546	46.19	6,831
2005	99,247.65	31,799	35,452	63,796	47.19	1,352
2006	21,099.30	6,501	7,248	13,851	47.72	290
2007	21,366.27	6,273	6,994	14,373	48.72	295
2008	132,857.20	37,572	41,888	90,969	49.46	1,839
2009	5,977.08	1,614	1,799	4,178	49.99	84

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2010	18,300.47	4,676	5,213	13,087	50.99	257
2011	20,776.70	5,040	5,619	15,158	51.52	294
2012	7,943.52	1,810	2,018	5,926	52.53	113
2013	93,193.26	19,999	22,297	70,897	53.07	1,336
2014	11,063.41	2,210	2,464	8,600	54.07	159
2015	2,375.70	442	493	1,883	54.62	34
2016	108,946.54	18,673	20,818	88,128	55.61	1,585
2017	88,797.46	13,888	15,483	73,314	56.62	1,295
2018	1,675.04	239	266	1,409	57.17	25
2019	189.14	24	27	162	58.17	3
	3,374,003.70	1,429,951	1,594,150	1,779,854		42,665

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.7 1.26

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	770.06	770	770			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,545	1,545			
1923	444.90	445	445			
1924	49,481.98	49,482	49,482			
1925	9,550.78	9,551	9,551			
1926	1,437.54	1,438	1,438			
1927	12,577.28	12,577	12,577			
1928	169.18	168	169			
1929	1,786.94	1,764	1,787			
1930	5,907.90	5,791	5,908			
1931	886.67	863	887			
1932	690.68	667	691			
1933	4,845.58	4,649	4,846			
1934	599.15	571	599			
1937	206.12	192	206			
1939	941.28	865	941			
1941	1,497.83	1,356	1,498			
1942	1,321.59	1,188	1,322			
1943	3,799.03	3,389	3,799			
1944	480.46	425	480			
1945	7,388.06	6,491	7,388			
1946	24,241.93	21,134	24,242			
1947	1,212.46	1,049	1,211	2	6.74	
1948	11,813.70	10,141	11,706	108	7.08	15
1949	155,416.10	132,352	152,777	2,639	7.42	356
1950	314,103.69	265,355	306,306	7,797	7.76	1,005
1951	117,565.93	98,520	113,724	3,842	8.10	474
1952	14,011.46	11,646	13,443	568	8.44	67
1953	64,035.02	52,778	60,923	3,112	8.79	354

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1954	82,747.60	67,621	78,057	4,691	9.14	513
1955	21,708.32	17,592	20,307	1,401	9.48	148
1956	33,265.27	26,725	30,849	2,416	9.83	246
1957	16,795.88	13,373	15,437	1,359	10.19	133
1958	16,398.95	12,942	14,939	1,460	10.54	139
1959	32,555.72	25,459	29,388	3,168	10.90	291
1960	28,812.28	22,324	25,769	3,043	11.26	270
1961	30,404.90	23,339	26,941	3,464	11.62	298
1962	27,753.65	21,104	24,361	3,393	11.98	283
1963	14,913.85	11,230	12,963	1,951	12.35	158
1964	4,880.13	3,639	4,201	680	12.72	53
1965	18,536.25	13,683	15,795	2,742	13.09	209
1966	5,038.93	3,681	4,249	790	13.47	59
1967	4,718.58	3,412	3,939	780	13.85	56
1968	4,278.86	3,061	3,533	745	14.23	52
1969	8,771.59	6,207	7,165	1,607	14.62	110
1970	5,741.53	4,018	4,638	1,103	15.01	73
1971	25,767.69	17,826	20,577	5,191	15.41	337
1973	11,871.49	8,023	9,261	2,610	16.21	161
1974	25,525.37	17,046	19,677	5,849	16.61	352
1975	87,663.74	57,823	66,747	20,917	17.02	1,229
1976	4,598.73	2,995	3,457	1,142	17.44	65
1977	8,040.17	5,168	5,966	2,075	17.86	116
1978	13,389.00	8,491	9,801	3,588	18.29	196
1979	6,024.51	3,769	4,351	1,674	18.72	89
1980	2,625.97	1,620	1,870	756	19.15	39
1981	3,896.41	2,370	2,736	1,161	19.59	59
1982	4,195.18	3,018	3,484	711	17.64	40
1984	107,312.77	75,656	87,332	19,981	18.10	1,104
1985	3,250.91	2,266	2,616	635	18.36	35
1987	11,800.00	7,979	9,210	2,590	19.27	134
1989	18,115.32	11,918	13,757	4,358	19.89	219
1993	4,421.64	2,726	3,147	1,275	21.31	60
1995	3,605.96	2,140	2,470	1,136	22.10	51
1996	28,053.64	16,395	18,925	9,128	22.22	411
1998	37,254.30	20,814	24,026	13,228	23.10	573
1999	24,770.91	13,574	15,669	9,102	23.30	391
2000	23,959.75	12,797	14,772	9,188	23.77	387
2001	34,304.98	17,832	20,584	13,721	24.25	566
2002	6,262.15	3,178	3,668	2,594	24.50	106
2003	8,507.00	4,188	4,834	3,673	25.01	147

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2004	14,150.50	6,778	7,824	6,326	25.29	250
2005	14,063.28	6,539	7,548	6,515	25.60	254
2006	17,523.06	7,857	9,070	8,454	26.14	323
2007	55,195.64	23,922	27,614	27,582	26.48	1,042
2008	20,558.92	8,659	9,995	10,564	26.80	394
2011	27,987.49	10,389	11,992	15,995	27.95	572
2013	103,921.61	34,814	40,187	63,735	28.79	2,214
2014	188,343.09	59,742	68,962	119,381	29.06	4,108
2019	56,478.77	12,098	13,965	42,514	31.18	1,364
2020	20,252.13	3,888	4,488	15,764	31.56	499
2021	3,292.94	557	643	2,650	31.96	83
2022	36,972.61	5,368	6,196	30,776	32.38	950
2024	446,028.38	42,640	49,221	396,808	33.13	11,977
2025	65,974.61	4,585	5,293	60,682	33.47	1,813
	2,781,411.12	1,563,419	1,784,526	996,885		38,072
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,142	4,142			
1927	2,693.18	2,693	2,693			
1930	189.29	186	189			
1933	847.72	813	848			
1936	544.45	511	544			
1938	32.84	30	33			
1952	9,309.40	7,738	9,114	195	8.44	23
1956	5,775.22	4,640	5,465	310	9.83	32
1957	65,555.21	52,195	61,479	4,076	10.19	400
1958	3,928.05	3,100	3,651	277	10.54	26
1959	1,740.26	1,361	1,603	137	10.90	13
1960	10,837.04	8,397	9,891	946	11.26	84
1961	15,060.14	11,560	13,616	1,444	11.62	124
1962	44,412.35	33,771	39,778	4,634	11.98	387
1963	61,579.91	46,370	54,618	6,962	12.35	564
1964	33,613.04	25,062	29,520	4,093	12.72	322
1965	24,411.66	18,021	21,227	3,185	13.09	243
1966	17,104.75	12,497	14,720	2,385	13.47	177

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1967	43,814.66	31,678	37,313	6,502	13.85	469
1968	31,758.04	22,720	26,761	4,997	14.23	351
1969	35,461.98	25,093	29,557	5,905	14.62	404
1970	109,477.63	76,612	90,240	19,238	15.01	1,282
1971	28,682.10	19,842	23,371	5,311	15.41	345
1972	14,929.02	10,211	12,027	2,902	15.80	184
1973	43,388.65	29,322	34,538	8,851	16.21	546
1974	6,679.10	4,460	5,253	1,426	16.61	86
1975	2,388.78	1,576	1,856	532	17.02	31
1976	325.75	212	250	76	17.44	4
1977	310.42	200	236	75	17.86	4
1978	5,350.19	3,393	3,997	1,354	18.29	74
1980	6,000.02	3,702	4,361	1,640	19.15	86
1981	66,216.28	40,273	47,437	18,780	19.59	959
1982	55,560.11	39,975	47,086	8,474	17.64	480
1983	28,861.79	20,561	24,218	4,643	17.86	260
1984	5,806.34	4,093	4,821	985	18.10	54
1985	10,388.00	7,241	8,529	1,859	18.36	101
1986	10,162.46	6,959	8,197	1,966	18.99	104
1987	21,773.61	14,723	17,342	4,432	19.27	230
1988	9,500.30	6,339	7,467	2,034	19.58	104
1989	21,764.75	14,319	16,866	4,899	19.89	246
1990	17,697.49	11,472	13,513	4,185	20.22	207
1991	2,527.62	1,613	1,900	628	20.57	31
1993	14,187.04	8,746	10,302	3,885	21.31	182
1994	31,906.90	19,310	22,745	9,162	21.69	422
1995	24,723.97	14,671	17,281	7,443	22.10	337
1996	64,217.36	37,529	44,205	20,013	22.22	901
1997	106,890.33	61,109	71,979	34,911	22.66	1,541
1998	90,466.61	50,544	59,535	30,932	23.10	1,339
1999	26,987.42	14,789	17,420	9,568	23.30	411
2000	20,094.65	10,733	12,642	7,452	23.77	314
2001	27,792.71	14,447	17,017	10,776	24.25	444
2002	74,704.50	37,913	44,657	30,048	24.50	1,226
2003	35,723.93	17,587	20,715	15,009	25.01	600
2004	12,600.58	6,036	7,110	5,491	25.29	217
2005	1,094.30	509	600	495	25.60	19
2006	2,275.29	1,020	1,201	1,074	26.14	41
2007	50,329.62	21,813	25,693	24,637	26.48	930
2008	4,380.00	1,845	2,173	2,207	26.80	82
2009	6,511.91	2,639	3,108	3,403	27.16	125

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2010	2,023.74	786	926	1,098	27.55	40
2014	1,151,949.73	365,398	430,395	721,555	29.06	24,830
2017	18,705.63	4,811	5,667	13,039	30.32	430
2019	630,236.94	134,997	159,010	471,227	31.18	15,113
2020	35,373.19	6,792	8,000	27,373	31.56	867
2023	6,264.54	756	890	5,374	32.81	164
2024	2,560.25	245	289	2,272	33.13	69
	3,323,085.84	1,465,183	1,724,310	1,598,776		59,681
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1908	234.48	234	234			
1910	3,861.59	3,862	3,862			
1915	126.30	126	126			
1923	235.29	235	235			
1925	190.68	191	191			
1927	12,436.94	12,437	12,437			
1928	813.98	809	814			
1930	35.14	34	35			
1936	535.44	503	528	7	3.05	2
1937	4,312.45	4,020	4,221	92	3.39	27
1945	11.76	10	10	1	6.07	
1947	413.05	357	375	38	6.74	6
1948	6,553.87	5,626	5,907	647	7.08	91
1949	1,401.38	1,193	1,253	149	7.42	20
1950	22,787.70	19,251	20,213	2,575	7.76	332
1952	7.75	6	6	1	8.44	
1953	1,739.58	1,434	1,506	234	8.79	27
1954	0.58			1	9.14	
1955	740.69	600	630	111	9.48	12
1956	119.40	96	101	19	9.83	2
1957	1,800.86	1,434	1,506	295	10.19	29
1959	2,182.25	1,707	1,792	390	10.90	36
1960	2,606.73	2,020	2,121	486	11.26	43
1961	2,799.92	2,149	2,256	544	11.62	47
1962	2,082.30	1,583	1,662	420	11.98	35
1963	1,506.73	1,135	1,192	315	12.35	26
1964	244.55	182	191	53	12.72	4

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1965	873.68	645	677	196	13.09	15
1966	2,877.32	2,102	2,207	670	13.47	50
1967	6,144.27	4,442	4,664	1,480	13.85	107
1968	8,237.89	5,893	6,187	2,050	14.23	144
1969	1,214.79	860	903	312	14.62	21
1970	15,096.54	10,565	11,093	4,004	15.01	267
1971	1,337.23	925	971	366	15.41	24
1972	1,686.39	1,153	1,211	476	15.80	30
1973	475.61	321	337	139	16.21	9
1974	889.29	594	624	266	16.61	16
1975	1,607.08	1,060	1,113	494	17.02	29
1977	1,491.56	959	1,007	485	17.86	27
1980	1,550.75	957	1,005	546	19.15	29
1984	1,147.18	809	849	298	18.10	16
1985	56,276.04	39,230	41,190	15,086	18.36	822
1986	5,672.61	3,885	4,079	1,593	18.99	84
1988	3,743.66	2,498	2,623	1,121	19.58	57
1989	1,743.75	1,147	1,204	539	19.89	27
1990	2,013.56	1,305	1,370	643	20.22	32
1991	2,592.31	1,654	1,737	856	20.57	42
1994	417.47	253	266	152	21.69	7
1995	815.73	484	508	308	22.10	14
1996	2,818.09	1,647	1,729	1,089	22.22	49
1997	2,053.45	1,174	1,233	821	22.66	36
2003	2,522.29	1,242	1,304	1,218	25.01	49
2004	5,228.61	2,505	2,630	2,598	25.29	103
2006	3,917.66	1,757	1,845	2,073	26.14	79
2007	1,840.52	798	838	1,003	26.48	38
2011	2,842.27	1,055	1,108	1,735	27.95	62
2012	17,220.59	6,086	6,390	10,830	28.36	382
2015	14,049.51	4,180	4,389	9,661	29.52	327
2016	24,794.44	6,873	7,216	17,578	29.99	586
2017	102,116.02	26,264	27,576	74,540	30.32	2,458
2018	150,878.25	35,547	37,323	113,555	30.82	3,684
2019	52,911.67	11,334	11,900	41,011	31.18	1,315
2020	8,613.41	1,654	1,737	6,877	31.56	218
2023	79,428.28	9,579	10,058	69,371	32.81	2,114

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2024	294,630.33	28,167	29,574	265,056	33.13	8,000
2025	106,021.38	7,368	7,736	98,285	33.47	2,937
2026	758,949.48	32,179	33,787	725,163	33.84	21,429
	1,818,522.35	322,384	337,603	1,480,919		46,474
	7,923,019.31	3,350,986	3,846,439	4,076,580		144,227
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.3	1.82

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1924	91,901.99	81,106	79,411	12,491	8.81	1,418
1925	14,230.50	12,513	12,252	1,979	9.05	219
1926	263,035.17	230,453	225,638	37,397	9.29	4,026
1927	20,101.97	17,548	17,181	2,921	9.53	307
1928	102,059.62	88,751	86,897	15,163	9.78	1,550
1929	120,138.32	104,072	101,898	18,241	10.03	1,819
1930	280,452.16	242,011	236,955	43,497	10.28	4,231
1931	146,192.45	125,648	123,023	23,170	10.54	2,198
1932	14,900.11	12,754	12,488	2,413	10.80	223
1933	5,190.08	4,424	4,332	859	11.07	78
1934	9,383.89	7,964	7,798	1,586	11.35	140
1935	6,664.77	5,631	5,513	1,151	11.63	99
1936	4,157.49	3,497	3,424	734	11.92	62
1937	8,640.71	7,234	7,083	1,558	12.21	128
1938	6,200.15	5,165	5,057	1,143	12.52	91
1939	14,632.26	12,129	11,876	2,757	12.83	215
1940	14,249.95	11,752	11,506	2,743	13.15	209
1941	26,656.99	21,866	21,409	5,248	13.48	389
1942	26,786.62	21,851	21,394	5,392	13.82	390
1943	3,832.40	3,108	3,043	789	14.17	56
1944	5,139.72	4,144	4,057	1,082	14.53	74
1945	8,917.22	7,146	6,997	1,921	14.90	129
1946	330,577.03	263,229	257,729	72,848	15.28	4,768
1947	53,260.36	42,133	41,253	12,008	15.67	766
1948	100,342.03	78,829	77,182	23,160	16.08	1,440
1949	116,086.57	90,563	88,671	27,416	16.49	1,663
1950	1,565,385.74	1,212,235	1,186,908	378,478	16.92	22,369
1951	340,244.85	261,488	256,025	84,220	17.36	4,851
1952	587,501.87	447,988	438,628	148,874	17.81	8,359
1953	679,741.21	514,156	503,414	176,327	18.27	9,651
1954	1,317,049.65	987,958	967,317	349,733	18.74	18,662
1955	1,131,137.02	841,113	823,540	307,597	19.23	15,996
1956	1,700,326.49	1,253,260	1,227,076	473,251	19.72	23,999
1957	1,450,783.38	1,059,464	1,037,329	413,455	20.23	20,438
1958	2,901,190.85	2,098,518	2,054,674	846,517	20.75	40,796
1959	1,710,295.63	1,225,033	1,199,438	510,857	21.28	24,006
1960	2,787,736.80	1,976,701	1,935,402	852,335	21.82	39,062
1961	1,629,786.68	1,143,458	1,119,568	510,219	22.38	22,798
1962	1,739,364.82	1,207,345	1,182,120	557,245	22.94	24,291
1963	2,178,583.44	1,495,663	1,464,414	714,169	23.51	30,377
1964	2,168,724.12	1,471,848	1,441,097	727,627	24.10	30,192

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1965	2,731,843.40	1,832,521	1,794,234	937,609	24.69	37,975
1966	2,907,591.44	1,927,152	1,886,888	1,020,703	25.29	40,360
1967	3,029,378.44	1,982,819	1,941,392	1,087,986	25.91	41,991
1968	3,406,238.46	2,201,350	2,155,357	1,250,881	26.53	47,150
1969	3,809,224.92	2,429,790	2,379,024	1,430,200	27.16	52,658
1970	3,211,950.39	2,021,377	1,979,144	1,232,806	27.80	44,346
1971	3,095,616.81	1,921,356	1,881,213	1,214,404	28.45	42,686
1972	2,981,900.90	1,824,536	1,786,416	1,195,485	29.11	41,068
1973	2,710,882.86	1,634,473	1,600,324	1,110,559	29.78	37,292
1974	3,014,025.17	1,790,331	1,752,926	1,261,099	30.45	41,415
1975	2,175,741.94	1,272,374	1,245,790	929,952	31.14	29,864
1976	1,914,558.82	1,102,020	1,078,996	835,563	31.83	26,251
1977	2,313,903.80	1,310,595	1,283,213	1,030,691	32.52	31,694
1978	2,030,826.78	1,131,028	1,107,397	923,429	33.23	27,789
1979	4,122,269.44	2,256,819	2,209,667	1,912,602	33.94	56,352
1980	8,402,033.09	4,519,202	4,424,782	3,977,251	34.66	114,750
1981	6,116,168.35	3,230,132	3,162,645	2,953,523	35.39	83,456
1982	6,677,864.27	3,927,920	3,845,854	2,832,010	31.68	89,394
1983	1,510,811.76	869,019	850,863	659,949	32.68	20,194
1984	2,198,788.46	1,245,834	1,219,805	978,984	33.08	29,594
1985	2,913,490.15	1,624,853	1,590,905	1,322,585	33.51	39,468
1986	4,700,328.48	2,559,329	2,505,857	2,194,471	34.51	63,589
1987	2,031,792.43	1,087,618	1,064,894	966,898	34.94	27,673
1988	4,098,795.47	2,155,966	2,110,921	1,987,874	35.37	56,202
1989	3,525,477.71	1,807,160	1,769,403	1,756,075	36.37	48,284
1990	3,267,236.23	1,643,093	1,608,764	1,658,472	36.82	45,043
1991	3,093,565.86	1,525,128	1,493,264	1,600,302	37.28	42,927
1992	2,395,536.62	1,148,420	1,124,426	1,271,111	38.28	33,206
1993	1,056,754.21	495,829	485,470	571,285	38.74	14,747
1994	862,530.02	395,729	387,461	475,069	39.22	12,113
1995	5,041,341.70	2,243,397	2,196,526	2,844,816	40.22	70,731
1996	4,880,193.36	2,119,956	2,075,664	2,804,530	40.69	68,924
1997	1,897,431.82	803,562	786,773	1,110,659	41.18	26,971
1998	2,305,476.97	944,093	924,368	1,381,109	42.18	32,743
1999	1,110,362.15	442,257	433,017	677,345	42.67	15,874
2000	2,544,468.60	984,709	964,136	1,580,333	43.17	36,607
2001	5,843,168.34	2,193,525	2,147,696	3,695,473	43.68	84,603
2002	1,045,333.91	377,470	369,584	675,750	44.68	15,124
2003	3,310,218.35	1,155,928	1,131,777	2,178,441	45.19	48,206
2004	1,744,006.36	587,905	575,622	1,168,384	45.72	25,555
2005	1,015,066.62	327,460	320,618	694,448	46.72	14,864

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2006	2,666,822.92	827,248	809,964	1,856,859	47.25	39,299
2007	879,397.21	261,797	256,327	623,070	47.78	13,040
2008	2,135,574.21	612,056	599,268	1,536,306	48.53	31,657
2009	2,488,356.94	681,312	667,077	1,821,280	49.07	37,116
2010	2,041,276.18	532,365	521,242	1,520,034	49.61	30,640
2011	1,833,701.09	453,841	444,359	1,389,342	50.17	27,693
2012	2,339,036.37	547,335	535,900	1,803,137	50.73	35,544
2013	3,387,743.57	741,916	726,415	2,661,328	51.72	51,456
2014	4,885,215.35	1,002,446	981,502	3,903,713	52.29	74,655
2015	9,525,814.87	1,821,336	1,783,283	7,742,532	52.86	146,472
2016	12,515,711.01	2,216,532	2,170,222	10,345,489	53.44	193,591
2017	23,523,097.37	3,829,560	3,749,549	19,773,548	54.01	366,109
2018	19,010,537.75	2,817,362	2,758,499	16,252,039	54.60	297,656
2019	10,559,636.35	1,408,655	1,379,224	9,180,412	55.20	166,312
2020	10,769,271.50	1,283,697	1,256,877	9,512,395	55.40	171,704
2021	24,332,976.68	2,530,630	2,477,758	21,855,219	56.00	390,272
2022	23,012,525.53	2,038,910	1,996,311	21,016,214	56.61	371,246
2023	26,711,471.87	1,960,622	1,919,659	24,791,813	56.85	436,092
2024	15,432,667.49	892,008	873,371	14,559,296	57.10	254,979
2025	21,613,862.70	907,782	888,816	20,725,047	57.02	363,470
2026	17,849,063.90	460,506	450,885	17,398,179	56.64	307,171
2027	10,038,690.55	91,352	89,443	9,949,247	54.45	182,723
	400,278,229.35	113,675,052	111,300,043	288,978,186		6,111,165
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1901	994.93	949	957	38	3.44	11
1903	400.38	379	382	18	3.98	5
1904	266.55	251	253	13	4.25	3
1905	1,257.62	1,182	1,192	66	4.51	15
1906	3,398.58	3,183	3,210	189	4.75	40
1907	8,718.80	8,138	8,207	512	5.00	102
1908	17,720.18	16,485	16,625	1,095	5.23	209
1909	366.96	340	343	24	5.46	4
1910	2,452.39	2,267	2,286	166	5.68	29
1911	4.73	4	4	1	5.91	
1913	1,966.53	1,800	1,815	151	6.34	24
1914	283.86	259	261	23	6.56	4

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1916	11.98	11	11	1	6.99	
1920	4,210.35	3,767	3,799	411	7.89	52
1921	32,526.72	29,010	29,257	3,270	8.11	403
1922	22,747.01	20,218	20,390	2,357	8.34	283
1923	31,284.72	27,706	27,942	3,343	8.58	390
1924	37,465.61	33,065	33,346	4,120	8.81	468
1925	39,109.23	34,390	34,682	4,427	9.05	489
1926	10,283.75	9,010	9,087	1,197	9.29	129
1927	26,881.19	23,465	23,664	3,217	9.53	338
1928	8,774.78	7,631	7,696	1,079	9.78	110
1929	744.31	645	650	94	10.03	9
1930	67,623.54	58,354	58,850	8,773	10.28	853
1931	191,406.68	164,508	165,907	25,500	10.54	2,419
1932	5,792.44	4,958	5,000	792	10.80	73
1933	10,113.23	8,621	8,694	1,419	11.07	128
1934	1,550.45	1,316	1,327	223	11.35	20
1935	2,214.43	1,871	1,887	328	11.63	28
1936	16,073.34	13,519	13,634	2,439	11.92	205
1937	3,527.96	2,954	2,979	549	12.21	45
1938	3,158.41	2,631	2,653	505	12.52	40
1939	1,631.17	1,352	1,363	268	12.83	21
1940	9,614.73	7,929	7,996	1,618	13.15	123
1941	1,309.18	1,074	1,083	226	13.48	17
1942	754.64	616	621	133	13.82	10
1944	433.76	350	353	81	14.53	6
1946	69,428.84	55,284	55,754	13,675	15.28	895
1947	14,257.85	11,279	11,375	2,883	15.67	184
1948	8,112.29	6,373	6,427	1,685	16.08	105
1949	12,304.05	9,599	9,681	2,623	16.49	159
1950	8,340.09	6,459	6,514	1,826	16.92	108
1951	12,663.19	9,732	9,815	2,848	17.36	164
1952	146,792.94	111,934	112,886	33,907	17.81	1,904
1953	326,118.39	246,676	248,773	77,345	18.27	4,233
1954	7,239.09	5,430	5,476	1,763	18.74	94
1955	100,988.44	75,095	75,733	25,255	19.23	1,313
1956	590,193.55	435,014	438,712	151,481	19.72	7,682
1957	1,535,821.68	1,121,564	1,131,099	404,723	20.23	20,006
1958	168,161.95	121,637	122,671	45,491	20.75	2,192
1959	1,058,550.91	758,208	764,654	293,897	21.28	13,811
1960	595,111.16	421,975	425,562	169,549	21.82	7,770
1961	1,195,260.00	838,594	845,723	349,537	22.38	15,618

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1962	955,711.74	663,388	669,028	286,684	22.94	12,497
1963	1,705,666.27	1,170,991	1,180,946	524,720	23.51	22,319
1964	2,839,204.91	1,926,883	1,943,264	895,941	24.10	37,176
1965	2,167,416.71	1,453,903	1,466,263	701,154	24.69	28,398
1966	1,908,643.60	1,265,049	1,275,803	632,840	25.29	25,023
1967	2,137,222.68	1,398,876	1,410,768	726,455	25.91	28,038
1968	3,231,597.99	2,088,485	2,106,240	1,125,358	26.53	42,418
1969	2,881,686.74	1,838,142	1,853,768	1,027,918	27.16	37,847
1970	2,381,353.69	1,498,657	1,511,397	869,956	27.80	31,293
1971	2,163,125.15	1,342,587	1,354,001	809,125	28.45	28,440
1972	3,186,239.32	1,949,564	1,966,138	1,220,102	29.11	41,914
1973	1,157,595.11	697,949	703,882	453,713	29.78	15,235
1974	535,736.81	318,228	320,933	214,804	30.45	7,054
1975	597,406.04	349,363	352,333	245,073	31.14	7,870
1976	403,380.31	232,186	234,160	169,220	31.83	5,316
1977	602,932.67	341,501	344,404	258,529	32.52	7,950
1978	572,536.95	318,863	321,574	250,963	33.23	7,552
1979	1,002,194.38	548,671	553,335	448,859	33.94	13,225
1980	950,653.79	511,328	515,675	434,979	34.66	12,550
1981	2,953,230.44	1,559,690	1,572,949	1,380,281	35.39	39,002
1982	4,609,885.07	2,711,534	2,734,585	1,875,300	31.68	59,195
1983	442,745.66	254,667	256,832	185,914	32.68	5,689
1984	1,511,442.28	856,383	863,663	647,779	33.08	19,582
1985	1,484,604.85	827,964	835,003	649,602	33.51	19,385
1986	1,322,738.76	720,231	726,354	596,385	34.51	17,282
1987	1,637,181.76	876,383	883,833	753,348	34.94	21,561
1988	1,740,164.97	915,327	923,108	817,057	35.37	23,100
1989	1,553,781.86	796,469	803,240	750,542	36.37	20,636
1990	1,285,574.26	646,515	652,011	633,563	36.82	17,207
1991	825,996.00	407,216	410,678	415,318	37.28	11,141
1992	2,797,530.30	1,341,136	1,352,537	1,444,993	38.28	37,748
1993	853,094.03	400,272	403,675	449,419	38.74	11,601
1994	1,520,827.45	697,756	703,688	817,140	39.22	20,835
1995	1,202,826.49	535,258	539,808	663,018	40.22	16,485
1996	8,799,219.56	3,822,381	3,854,876	4,944,344	40.69	121,513
1997	7,682,282.40	3,253,447	3,281,105	4,401,177	41.18	106,877
1998	3,519,039.60	1,441,047	1,453,298	2,065,742	42.18	48,974
1999	440,440.35	175,427	176,918	263,522	42.67	6,176
2000	8,069,150.99	3,122,761	3,149,308	4,919,843	43.17	113,964
2001	2,127,731.71	798,750	805,540	1,322,191	43.68	30,270
2002	5,012,303.41	1,809,943	1,825,330	3,186,974	44.68	71,329

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2003	2,478,182.37	865,381	872,738	1,605,445	45.19	35,527
2004	2,639,714.54	889,848	897,413	1,742,302	45.72	38,108
2005	2,713,620.35	875,414	882,856	1,830,764	46.72	39,186
2006	1,306,493.99	405,274	408,719	897,775	47.25	19,001
2007	911,020.48	271,211	273,517	637,504	47.78	13,342
2008	2,773,117.35	794,775	801,532	1,971,586	48.53	40,626
2009	548,782.02	150,257	151,534	397,248	49.07	8,096
2010	2,396,718.53	625,064	630,378	1,766,341	49.61	35,605
2011	1,319,809.92	326,653	329,430	990,380	50.17	19,740
2012	2,637,262.23	617,119	622,365	2,014,897	50.73	39,718
2013	4,747,614.04	1,039,727	1,048,566	3,699,048	51.72	71,521
2014	15,609,380.67	3,203,045	3,230,275	12,379,106	52.29	236,739
2015	16,426,455.69	3,140,738	3,167,438	13,259,018	52.86	250,833
2016	11,943,214.05	2,115,143	2,133,124	9,810,090	53.44	183,572
2017	7,070,631.23	1,151,099	1,160,885	5,909,747	54.01	109,419
2018	60,800,356.07	9,010,613	9,087,214	51,713,142	54.60	947,127
2019	7,269,821.99	969,794	978,038	6,291,784	55.20	113,982
2020	9,034,425.10	1,076,903	1,086,058	7,948,367	55.40	143,472
2021	3,412,529.80	354,903	357,920	3,054,610	56.00	54,547
2022	7,418,865.84	657,312	662,900	6,755,966	56.61	119,342
2023	9,770,489.13	717,154	723,251	9,047,238	56.85	159,142
2024	3,829,544.75	221,348	223,230	3,606,315	57.10	63,158
2025	4,770,641.48	200,367	202,070	4,568,571	57.02	80,122
2026	5,987,417.95	154,475	155,788	5,831,630	56.64	102,960
2027	11,956,850.36	108,807	109,732	11,847,118	54.45	217,578
	298,961,476.53	82,556,656	83,258,483	215,702,993		4,477,473
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1939	2,177.75	1,805	1,926	252	12.83	20
1940	1,536.91	1,267	1,352	185	13.15	14
1941	21,902.54	17,966	19,167	2,736	13.48	203
1942	175.01	143	153	22	13.82	2
1943	1,158.45	940	1,003	156	14.17	11
1944	4,047.03	3,263	3,481	566	14.53	39
1945	226.73	182	194	33	14.90	2
1946	6,225.29	4,957	5,288	937	15.28	61
1947	6,818.63	5,394	5,754	1,064	15.67	68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1948	2,784.84	2,188	2,334	451	16.08	28
1949	65,466.05	51,072	54,485	10,981	16.49	666
1951	15,890.12	12,212	13,028	2,862	17.36	165
1952	2,224.37	1,696	1,809	415	17.81	23
1953	25,289.89	19,129	20,407	4,883	18.27	267
1954	19,638.16	14,731	15,715	3,923	18.74	209
1955	9,084.12	6,755	7,206	1,878	19.23	98
1956	33,542.65	24,723	26,375	7,168	19.72	363
1957	44,630.29	32,592	34,770	9,860	20.23	487
1958	14,436.03	10,442	11,140	3,296	20.75	159
1959	50,039.18	35,842	38,237	11,802	21.28	555
1960	43,923.86	31,145	33,226	10,698	21.82	490
1961	121,637.35	85,341	91,044	30,594	22.38	1,367
1962	188,330.21	130,726	139,461	48,869	22.94	2,130
1963	387,321.59	265,908	283,676	103,645	23.51	4,409
1964	422,874.19	286,992	306,169	116,705	24.10	4,843
1965	297,490.46	199,557	212,892	84,599	24.69	3,426
1966	627,131.63	415,663	443,438	183,693	25.29	7,263
1967	273,278.12	178,869	190,821	82,457	25.91	3,182
1968	485,382.24	313,688	334,649	150,733	26.53	5,682
1969	406,351.62	259,200	276,520	129,831	27.16	4,780
1970	312,806.78	196,859	210,013	102,793	27.80	3,698
1971	247,866.42	153,843	164,123	83,743	28.45	2,944
1972	146,053.15	89,366	95,338	50,716	29.11	1,742
1973	299,123.70	180,351	192,402	106,721	29.78	3,584
1974	290,179.33	172,367	183,885	106,294	30.45	3,491
1975	103,541.30	60,551	64,597	38,944	31.14	1,251
1976	245,303.49	141,197	150,632	94,671	31.83	2,974
1977	113,099.80	64,060	68,341	44,759	32.52	1,376
1978	335,550.77	186,878	199,366	136,185	33.23	4,098
1979	149,948.17	82,092	87,578	62,371	33.94	1,838
1980	207,811.93	111,776	119,245	88,567	34.66	2,555
1981	213,658.00	112,839	120,379	93,279	35.39	2,636
1982	223,462.92	131,441	140,224	83,239	31.68	2,627
1983	338,198.73	194,532	207,531	130,668	32.68	3,998
1984	131,977.76	74,779	79,776	52,202	33.08	1,578
1985	385,690.07	215,099	229,472	156,218	33.51	4,662
1986	619,012.82	337,052	359,574	259,438	34.51	7,518
1987	117,624.51	62,964	67,171	50,453	34.94	1,444
1988	163,685.99	86,099	91,852	71,834	35.37	2,031
1989	371,166.63	190,260	202,974	168,193	36.37	4,624

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1990	80,628.44	40,548	43,257	37,371	36.82	1,015
1991	521,531.06	257,115	274,296	247,235	37.28	6,632
1992	1,269,533.88	608,615	649,284	620,250	38.28	16,203
1993	607,774.42	285,168	304,223	303,551	38.74	7,836
1995	936.49	417	445	492	40.22	12
1996	630,367.17	273,831	292,129	338,238	40.69	8,313
1997	665,541.97	281,857	300,691	364,851	41.18	8,860
1998	938,366.92	384,261	409,938	528,429	42.18	12,528
1999	344,071.34	137,044	146,202	197,870	42.67	4,637
2000	3,564,481.06	1,379,454	1,471,632	2,092,849	43.17	48,479
2001	401,484.87	150,717	160,788	240,697	43.68	5,510
2002	1,527,303.04	551,509	588,362	938,941	44.68	21,015
2003	337,376.48	117,812	125,684	211,692	45.19	4,684
2004	4,162,517.82	1,403,185	1,496,948	2,665,569	45.72	58,302
2005	6,296,305.58	2,031,188	2,166,916	4,129,390	46.72	88,386
2006	2,563,829.69	795,300	848,443	1,715,386	47.25	36,304
2007	1,032,740.16	307,447	327,991	704,749	47.78	14,750
2008	147,068.63	42,150	44,967	102,102	48.53	2,104
2009	3,165,760.79	866,785	924,705	2,241,056	49.07	45,671
2010	946,493.92	246,846	263,341	683,153	49.61	13,770
2011	2,244,810.99	555,591	592,717	1,652,094	50.17	32,930
2012	501,243.01	117,291	125,129	376,114	50.73	7,414
2013	940,200.89	205,904	219,663	720,538	51.72	13,932
2014	486,379.25	99,805	106,474	379,905	52.29	7,265
2015	2,317,668.03	443,138	472,749	1,844,919	52.86	34,902
2016	9,527,419.74	1,687,306	1,800,055	7,727,365	53.44	144,599
2017	7,576,741.28	1,233,493	1,315,917	6,260,824	54.01	115,920
2018	5,180,739.92	767,786	819,091	4,361,649	54.60	79,884
2019	4,107,654.90	547,961	584,577	3,523,078	55.20	63,824
2020	12,049,817.05	1,436,338	1,532,317	10,517,500	55.40	189,847
2021	3,972,231.99	413,112	440,717	3,531,515	56.00	63,063
2022	7,559,266.30	669,751	714,505	6,844,761	56.61	120,911
2023	1,591,099.64	116,787	124,591	1,466,509	56.85	25,796
2024	5,547,626.22	320,653	342,080	5,205,547	57.10	91,165

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2025	436,141.07	18,318	19,542	416,599	57.02	7,306
2026	4,705,426.21	121,400	129,512	4,575,914	56.64	80,789
2027	10,558,115.02	96,079	102,499	10,455,616	54.45	192,022
	117,103,472.82	24,270,755	25,892,573	91,210,900		1,778,261
	816,343,178.70	220,502,463	220,451,100	595,892,079		12,366,899
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					48.2	1.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1901	665.32	665	665			
1902	1,876.45	1,876	1,876			
1903	661.31	661	661			
1904	1,470.23	1,470	1,470			
1905	930.38	930	930			
1906	1,039.29	1,039	1,039			
1907	1,672.43	1,672	1,672			
1908	4,594.00	4,594	4,594			
1909	1,516.23	1,516	1,516			
1910	781.01	781	781			
1911	3,276.38	3,276	3,276			
1912	2,805.58	2,806	2,806			
1913	870.86	871	871			
1914	3,083.63	3,084	3,084			
1915	3,725.15	3,725	3,725			
1916	2,084.30	2,084	2,084			
1917	2,302.84	2,303	2,303			
1918	1,613.19	1,613	1,613			
1919	5,743.39	5,743	5,743			
1920	5,437.10	5,437	5,437			
1921	2,270.62	2,271	2,271			
1922	33,123.16	33,123	33,123			
1923	7,935.08	7,935	7,935			
1924	36,316.13	36,316	36,316			
1925	7,038.34	7,038	7,038			
1926	16,015.63	16,016	16,016			
1927	19,332.45	19,332	19,332			
1928	14,711.22	14,711	14,711			
1929	22,640.69	22,641	22,641			
1930	11,103.53	11,104	11,104			
1931	3,414.62	3,415	3,415			
1932	1,643.47	1,643	1,643			
1933	93.97	94	94			
1934	201.46	201	201			
1935	1,404.76	1,405	1,405			
1936	2,219.81	2,220	2,220			
1937	1,507.39	1,507	1,507			
1938	1,013.48	1,013	1,013			
1939	4,543.85	4,544	4,544			
1940	3,443.16	3,443	3,443			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1941	6,305.26	6,305	6,305			
1942	455.82	456	456			
1943	1,059.36	1,059	1,059			
1944	2,021.15	2,021	2,021			
1945	233.29	233	233			
1946	3,466.43	3,466	3,466			
1947	4,534.23	4,534	4,534			
1948	13,944.47	13,944	13,944			
1949	14,981.32	14,981	14,981			
1950	9,771.29	9,771	9,771			
1951	14,464.65	14,465	14,465			
1952	19,332.52	19,333	19,333			
1953	13,918.64	13,919	13,919			
1954	23,732.78	23,733	23,733			
1955	45,943.45	45,943	45,943			
1956	22,722.46	22,722	22,722			
1957	31,202.14	31,202	31,202			
1958	12,729.72	12,730	12,730			
1959	34,438.45	34,438	34,438			
1960	5,230.46	5,230	5,230			
1962	3,625.02	3,625	3,625			
1968	316.24	316	316			
2025	30,687.51	30,688	30,691		3-	
	551,238.55	551,232	551,242		3-	
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1903	827.90	828	828			
1904	1,600.92	1,601	1,601			
1905	59.45	59	59			
1906	3,388.02	3,388	3,388			
1908	45.16	45	45			
1910	2,040.42	2,040	2,040			
1911	13,104.26	13,104	13,104			
1912	4,993.79	4,994	4,994			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1923	297.99	298	298			
1943	508.36	508	508			
1952	86,661.17	86,661	86,661			
	113,527.44	113,526	113,527			
	664,765.99	664,758	664,769		3-	

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1972	20,322.31	14,100	13,751	6,571	20.82	316
1973	49,345.95	33,773	32,937	16,409	21.46	765
1974	11,909.87	8,036	7,837	4,073	22.12	184
1975	42,410.34	28,203	27,505	14,906	22.78	654
1976	438,648.31	287,315	280,201	158,447	23.46	6,754
1977	450,097.41	290,245	283,059	167,039	24.15	6,917
1978	651,167.85	413,205	402,975	248,193	24.85	9,988
1979	506,537.56	316,211	308,382	198,156	25.55	7,756
1980	1,089,756.70	668,762	652,204	437,552	26.27	16,656
1981	1,414,737.42	853,002	831,883	582,855	27.00	21,587
1982	1,937,296.50	1,244,907	1,214,085	723,212	25.17	28,733
1983	2,350,279.42	1,487,257	1,450,434	899,845	25.68	35,041
1984	3,226,207.67	2,009,282	1,959,535	1,266,673	26.19	48,365
1985	3,417,184.57	2,093,367	2,041,538	1,375,647	26.72	51,484
1986	4,259,617.97	2,547,678	2,484,601	1,775,017	27.72	64,034
1987	7,464,772.73	4,386,300	4,277,701	3,187,072	28.25	112,817
1988	10,680,938.15	6,162,901	6,010,315	4,670,623	28.78	162,287
1989	12,987,147.44	7,302,673	7,121,868	5,865,279	29.78	196,954
1990	14,789,230.32	8,153,303	7,951,438	6,837,793	30.32	225,521
1991	8,906,554.67	4,810,430	4,691,330	4,215,225	30.87	136,548
1992	6,937,052.92	3,643,340	3,553,136	3,383,917	31.87	106,179
1993	5,160,655.43	2,651,545	2,585,896	2,574,759	32.41	79,443
1994	9,370,274.38	4,704,815	4,588,330	4,781,945	32.97	145,039
1995	15,061,987.74	7,383,386	7,200,583	7,861,405	33.54	234,389
1996	9,053,456.12	4,300,392	4,193,920	4,859,536	34.54	140,693
1997	13,968,715.89	6,464,722	6,304,664	7,664,052	35.11	218,287
1998	9,859,958.72	4,412,332	4,303,088	5,556,870	36.11	153,887
1999	10,393,923.82	4,521,357	4,409,414	5,984,510	36.69	163,110
2000	10,852,181.02	4,583,961	4,470,468	6,381,713	37.26	171,275
2001	10,948,644.53	4,455,003	4,344,703	6,603,942	38.26	172,607
2002	10,121,532.85	3,986,872	3,888,162	6,233,371	38.85	160,447
2003	14,201,717.95	5,406,594	5,272,734	8,928,984	39.45	226,337
2004	13,249,953.11	4,836,233	4,716,494	8,533,459	40.45	210,963
2005	14,237,858.72	5,006,031	4,882,088	9,355,771	41.04	227,967
2006	14,924,266.97	5,011,569	4,887,489	10,036,778	42.04	238,744
2007	14,082,947.89	4,534,709	4,422,435	9,660,513	42.64	226,560
2008	11,781,163.90	3,652,161	3,561,738	8,219,426	43.40	189,388
2009	11,312,902.41	3,348,619	3,265,711	8,047,191	44.00	182,891
2010	11,814,146.50	3,307,961	3,226,060	8,588,086	45.00	190,846
2011	16,645,277.12	4,420,986	4,311,528	12,333,749	45.61	270,418
2012	22,274,467.33	5,593,119	5,454,640	16,819,827	46.23	363,829

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2013	29,775,840.44	6,994,345	6,821,174	22,954,667	47.23	486,019
2014	33,042,611.23	7,269,374	7,089,394	25,953,218	47.85	542,387
2015	31,373,824.42	6,393,985	6,235,678	25,138,146	48.85	514,599
2016	43,838,053.69	8,267,857	8,063,155	35,774,898	49.48	723,017
2017	39,403,097.72	6,785,213	6,617,220	32,785,878	50.48	649,483
2018	51,304,584.33	8,044,559	7,845,386	43,459,198	51.10	850,474
2019	71,420,538.22	10,013,159	9,765,246	61,655,292	52.11	1,183,176
2020	79,126,628.04	9,851,265	9,607,360	69,519,268	52.74	1,318,151
2021	87,954,269.55	9,551,834	9,315,343	78,638,927	53.38	1,473,191
2022	108,337,505.72	9,945,383	9,699,148	98,638,358	54.38	1,813,872
2023	129,045,033.08	9,755,805	9,514,264	119,530,769	55.02	2,172,497
2024	101,317,304.46	5,997,984	5,849,482	95,467,823	55.67	1,714,888
2025	117,384,767.13	4,988,853	4,865,335	112,519,432	56.32	1,997,859
2026	118,050,495.18	3,022,093	2,947,270	115,103,225	56.98	2,020,064
2027	118,221,442.05	1,028,527	1,003,062	117,218,380	56.97	2,057,546
	1,490,543,243.74	247,246,893	241,125,373	1,249,417,870		24,723,883
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1973	283,639.82	194,126	195,753	87,886	21.46	4,095
1974	566,917.62	382,505	385,712	181,206	22.12	8,192
1975	1,574,070.52	1,046,757	1,055,532	518,538	22.78	22,763
1976	1,074,844.16	704,023	709,925	364,919	23.46	15,555
1977	1,327,053.59	855,751	862,925	464,129	24.15	19,219
1978	1,697,681.56	1,077,281	1,086,312	611,369	24.85	24,602
1979	1,917,426.89	1,196,973	1,207,008	710,419	25.55	27,805
1980	2,061,256.28	1,264,952	1,275,556	785,700	26.27	29,909
1981	1,501,220.22	905,146	912,734	588,486	27.00	21,796
1982	1,522,652.85	978,457	986,660	535,993	25.17	21,295
1983	801,140.07	506,961	511,211	289,929	25.68	11,290
1984	1,002,010.14	624,052	629,284	372,727	26.19	14,232
1985	1,284,950.21	787,160	793,759	491,191	26.72	18,383
1986	1,956,686.24	1,170,294	1,180,105	776,581	27.72	28,015
1987	3,172,544.01	1,864,187	1,879,815	1,292,729	28.25	45,760
1988	5,780,611.86	3,335,413	3,363,375	2,417,237	28.78	83,990
1989	4,255,041.58	2,392,610	2,412,668	1,842,374	29.78	61,866
1990	4,717,912.04	2,600,985	2,622,790	2,095,122	30.32	69,100
1991	2,188,191.57	1,181,842	1,191,750	996,442	30.87	32,279

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1992	2,713,434.17	1,425,096	1,437,043	1,276,391	31.87	40,050
1993	2,615,542.14	1,343,866	1,355,132	1,260,410	32.41	38,890
1994	5,283,059.33	2,652,624	2,674,862	2,608,198	32.97	79,108
1995	5,545,624.08	2,718,465	2,741,255	2,804,370	33.54	83,613
1996	6,467,951.98	3,072,277	3,098,033	3,369,919	34.54	97,566
1997	9,914,325.93	4,588,350	4,626,815	5,287,511	35.11	150,598
1998	7,401,823.32	3,312,316	3,340,084	4,061,739	36.11	112,482
1999	5,197,585.60	2,260,950	2,279,904	2,917,682	36.69	79,523
2000	4,052,244.80	1,711,668	1,726,017	2,326,227	37.26	62,432
2001	7,073,377.26	2,878,157	2,902,285	4,171,092	38.26	109,020
2002	3,163,896.25	1,246,259	1,256,707	1,907,190	38.85	49,091
2003	3,575,942.77	1,361,361	1,372,774	2,203,169	39.45	55,847
2004	8,078,846.50	2,948,779	2,973,499	5,105,347	40.45	126,214
2005	6,583,538.49	2,314,772	2,334,177	4,249,361	41.04	103,542
2006	3,970,205.05	1,333,195	1,344,371	2,625,834	42.04	62,460
2007	5,598,535.66	1,802,728	1,817,841	3,780,695	42.64	88,665
2008	4,648,919.52	1,441,165	1,453,247	3,195,673	43.40	73,633
2009	5,578,260.41	1,651,165	1,665,007	3,913,253	44.00	88,938
2010	4,083,743.16	1,143,448	1,153,034	2,930,709	45.00	65,127
2011	5,577,827.94	1,481,471	1,493,891	4,083,937	45.61	89,540
2012	8,812,809.28	2,212,896	2,231,447	6,581,362	46.23	142,361
2013	5,522,126.93	1,297,148	1,308,022	4,214,105	47.23	89,225
2014	8,067,843.62	1,774,926	1,789,806	6,278,038	47.85	131,202
2015	15,551,588.97	3,169,414	3,195,984	12,355,605	48.85	252,929
2016	18,084,504.67	3,410,738	3,439,331	14,645,174	49.48	295,982
2017	20,998,329.82	3,615,912	3,646,225	17,352,105	50.48	343,742
2018	22,633,242.31	3,548,892	3,578,643	19,054,599	51.10	372,888
2019	28,497,573.97	3,995,360	4,028,854	24,468,720	52.11	469,559
2020	26,679,548.77	3,321,604	3,349,450	23,330,099	52.74	442,361
2021	24,387,997.28	2,648,537	2,670,740	21,717,257	53.38	406,843
2022	32,669,611.56	2,999,070	3,024,212	29,645,400	54.38	545,153
2023	32,069,769.57	2,424,475	2,444,800	29,624,970	55.02	538,440
2024	22,691,250.89	1,343,322	1,354,583	21,336,667	55.67	383,270
2025	22,674,778.59	963,678	971,757	21,703,022	56.32	385,352
2026	33,869,602.88	867,062	874,331	32,995,272	56.98	579,068
2027	23,188,512.70	201,740	203,431	22,985,081	56.97	403,459
	492,209,627.40	103,552,361	104,420,466	387,789,162		7,998,319

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1967	5,277.53	3,898	4,159	1,119	17.78	63
1968	11,832.07	8,637	9,214	2,618	18.36	143
1969	6,528.75	4,708	5,023	1,506	18.96	79
1970	24,075.19	17,150	18,297	5,779	19.56	295
1971	340,739.06	239,570	255,588	85,152	20.19	4,218
1972	517,897.14	359,327	383,351	134,546	20.82	6,462
1973	405,756.15	277,704	296,271	109,485	21.46	5,102
1974	613,000.21	413,597	441,250	171,750	22.12	7,764
1975	548,739.77	364,912	389,310	159,430	22.78	6,999
1976	339,917.60	222,646	237,532	102,386	23.46	4,364
1977	624,397.39	402,643	429,563	194,834	24.15	8,068
1978	518,002.60	328,704	350,681	167,322	24.85	6,733
1979	479,869.09	299,563	319,592	160,277	25.55	6,273
1980	696,608.79	427,495	456,077	240,532	26.27	9,156
1981	818,380.53	493,434	526,425	291,956	27.00	10,813
1982	740,219.81	475,665	507,468	232,752	25.17	9,247
1983	860,660.26	544,626	581,039	279,621	25.68	10,889
1984	1,377,933.91	858,177	915,554	462,380	26.19	17,655
1985	1,569,674.29	961,582	1,025,873	543,801	26.72	20,352
1986	1,859,097.65	1,111,926	1,186,269	672,829	27.72	24,272
1987	1,423,172.24	836,256	892,168	531,005	28.25	18,797
1988	2,086,413.80	1,203,861	1,284,350	802,063	28.78	27,869
1989	2,151,936.80	1,210,034	1,290,936	861,001	29.78	28,912
1990	2,274,033.35	1,253,675	1,337,495	936,538	30.32	30,888
1991	2,623,005.99	1,416,686	1,511,405	1,111,601	30.87	36,009
1992	2,153,923.70	1,131,241	1,206,875	947,049	31.87	29,716
1993	3,370,133.74	1,731,575	1,847,347	1,522,787	32.41	46,985
1994	3,434,793.94	1,724,610	1,839,916	1,594,878	32.97	48,374
1995	3,800,766.19	1,863,136	1,987,704	1,813,062	33.54	54,057
1996	4,707,831.54	2,236,220	2,385,732	2,322,099	34.54	67,229
1997	4,849,208.00	2,244,213	2,394,260	2,454,948	35.11	69,922
1998	5,657,646.40	2,531,797	2,701,071	2,956,575	36.11	81,877
1999	3,369,622.65	1,465,786	1,563,788	1,805,835	36.69	49,219
2000	4,912,995.88	2,075,249	2,213,999	2,698,997	37.26	72,437
2001	2,491,916.15	1,013,961	1,081,754	1,410,162	38.26	36,857
2002	4,123,481.73	1,624,239	1,732,835	2,390,647	38.85	61,535
2003	4,385,263.62	1,669,470	1,781,090	2,604,174	39.45	66,012
2004	4,603,543.15	1,680,293	1,792,636	2,810,907	40.45	69,491
2005	4,715,542.34	1,657,985	1,768,837	2,946,705	41.04	71,801
2006	6,329,710.09	2,125,517	2,267,628	4,062,082	42.04	96,624
2007	5,401,696.59	1,739,346	1,855,638	3,546,059	42.64	83,163

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2008	4,877,735.01	1,512,098	1,613,196	3,264,539	43.40	75,220
2009	4,319,969.28	1,278,711	1,364,205	2,955,764	44.00	67,176
2010	6,184,225.66	1,731,583	1,847,356	4,336,870	45.00	96,375
2011	7,160,270.89	1,901,768	2,028,919	5,131,352	45.61	112,505
2012	5,178,876.72	1,300,416	1,387,361	3,791,516	46.23	82,014
2013	5,515,815.30	1,295,665	1,382,292	4,133,523	47.23	87,519
2014	7,520,760.91	1,654,567	1,765,190	5,755,571	47.85	120,284
2015	13,990,421.42	2,851,248	3,041,881	10,948,541	48.85	224,126
2016	12,487,549.75	2,355,152	2,512,616	9,974,934	49.48	201,595
2017	12,692,646.78	2,185,674	2,331,807	10,360,840	50.48	205,246
2018	16,636,399.84	2,608,587	2,782,996	13,853,404	51.10	271,104
2019	7,826,174.93	1,097,230	1,170,590	6,655,585	52.11	127,722
2020	4,754,869.81	591,981	631,561	4,123,309	52.74	78,182
2021	11,460,725.45	1,244,635	1,327,851	10,132,875	53.38	189,825
2022	15,241,818.43	1,399,199	1,492,749	13,749,070	54.38	252,833
2023	18,760,982.17	1,418,330	1,513,159	17,247,823	55.02	313,483
2024	21,547,836.26	1,275,632	1,360,920	20,186,916	55.67	362,617
2025	23,689,765.36	1,006,815	1,074,130	22,615,635	56.32	401,556
2026	30,005,343.56	768,137	819,494	29,185,849	56.98	512,212
2027	67,887,980.15	590,625	630,114	67,257,866	56.97	1,180,584
	388,965,413.36	72,319,167	77,154,385	311,811,029		6,268,899
	2,371,718,284.50	423,118,421	422,700,224	1,949,018,061		38,991,101
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					50.0	1.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1901	1,823.44	1,700	1,691	132	4.74	28
1902	858.12	796	792	66	5.04	13
1903	2,783.58	2,572	2,559	225	5.32	42
1904	6,859.36	6,312	6,280	579	5.59	104
1905	2,828.98	2,593	2,580	249	5.85	43
1906	4,634.90	4,232	4,211	424	6.09	70
1907	3,011.94	2,740	2,726	286	6.33	45
1908	6,470.50	5,865	5,835	635	6.55	97
1909	6,566.28	5,932	5,902	664	6.76	98
1910	8,992.96	8,097	8,056	937	6.97	134
1911	19,368.44	17,383	17,295	2,073	7.17	289
1912	12,488.38	11,174	11,118	1,371	7.36	186
1913	19,952.20	17,801	17,711	2,241	7.54	297
1914	52,379.23	46,596	46,361	6,019	7.72	780
1915	24,228.79	21,490	21,381	2,847	7.90	360
1916	19,636.02	17,368	17,280	2,356	8.07	292
1917	3,879.82	3,423	3,406	474	8.23	58
1918	4,097.87	3,605	3,587	511	8.39	61
1919	5,274.03	4,629	4,606	668	8.54	78
1920	2,322.08	2,033	2,023	299	8.69	34
1921	9,356.23	8,170	8,129	1,227	8.84	139
1922	14,230.62	12,396	12,333	1,897	8.98	211
1923	14,826.56	12,886	12,821	2,006	9.11	220
1924	43,133.11	37,401	37,212	5,921	9.24	641
2025	4,827.55	783	779	4,049	12.91	314
	294,830.99	257,977	256,674	38,157		4,634
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,183.84	1,089	1,117	67	5.59	12
1906	505.47	461	473	33	6.09	5
1911	733.05	658	675	58	7.17	8
1912	2,886.54	2,583	2,649	238	7.36	32
1914	339.20	302	310	30	7.72	4
1915	4,350.95	3,859	3,957	394	7.90	50
1916	121.20	107	110	11	8.07	1

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1924	17.25	15	15	2	9.24	
1928	52.02	45	46	6	9.73	1
1939	125.74	106	109	17	10.79	2
1940	30.00	25	26	4	10.87	
1943	25.03	21	22	3	11.10	
	10,370.29	9,271	9,507	863		115
	305,201.28	267,248	266,181	39,020		4,749
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.2	1.56

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	214,839	329,843	992,245	33.50	29,619
	1,322,088.00	214,839	329,843	992,245		29,619
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					33.5	2.24

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	46.55	47	47			
1916	176.30	176	176			
1919	842.73	843	843			
1920	200.76	201	201			
1921	59.74	60	60			
1923	335.53	336	336			
1924	940.41	940	940			
1926	1,101.08	1,101	1,101			
1927	2,415.27	2,415	2,415			
1928	45.42	45	45			
1929	633.14	633	633			
1930	742.57	743	743			
1931	2,305.44	2,305	2,305			
1935	51.51	50	52			
1936	381.52	368	382			
1937	1,295.79	1,239	1,296			
1940	174.33	163	174			
1941	66.28	61	66			
1942	2,206.15	2,024	2,196	10	3.97	3
1943	932.24	848	920	12	4.35	3
1945	649.55	581	630	19	5.10	4
1946	820.32	727	789	32	5.48	6
1947	2,534.09	2,225	2,414	120	5.86	20
1948	1,699.47	1,478	1,603	96	6.25	15
1949	1,260.93	1,087	1,179	82	6.63	12
1950	12,126.15	10,353	11,232	894	7.02	127
1951	8,935.99	7,558	8,200	736	7.40	99
1952	17,913.02	15,006	16,280	1,633	7.79	210
1953	15,733.05	13,052	14,160	1,573	8.18	192
1954	57,461.65	47,202	51,209	6,253	8.57	730
1955	21,547.00	17,525	19,013	2,534	8.96	283
1956	92,077.31	74,122	80,414	11,663	9.36	1,246
1957	22,345.95	17,807	19,319	3,027	9.75	310
1958	33,882.12	26,717	28,985	4,897	10.15	482
1959	4,179.56	3,261	3,538	642	10.55	61
1960	30,399.51	23,465	25,457	4,943	10.95	451
1961	34,928.66	26,669	28,933	5,996	11.35	528
1962	38,905.19	29,373	31,867	7,039	11.76	599
1963	23,326.10	17,417	18,896	4,431	12.16	364
1964	17,254.51	12,736	13,817	3,437	12.57	273
1965	12,413.99	9,057	9,826	2,588	12.98	199

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1966	22,899.01	16,506	17,907	4,992	13.40	373
1967	49,345.93	35,149	38,133	11,213	13.81	812
1968	36,608.05	25,755	27,941	8,667	14.23	609
1969	25,855.88	17,964	19,489	6,367	14.65	435
1970	35,399.60	24,286	26,348	9,052	15.07	601
1971	176,757.04	119,716	129,879	46,878	15.49	3,026
1972	51,793.31	34,615	37,554	14,240	15.92	894
1973	11,543.24	7,611	8,257	3,286	16.35	201
1974	60,537.62	39,375	42,718	17,820	16.78	1,062
1975	44,283.06	28,406	30,817	13,466	17.21	782
1976	69,206.53	43,759	47,474	21,733	17.65	1,231
1977	28,731.44	17,903	19,423	9,309	18.09	515
1978	34,885.08	21,418	23,236	11,649	18.53	629
1979	32,642.29	19,742	21,418	11,224	18.97	592
1980	102,943.95	61,295	66,498	36,445	19.42	1,877
1981	177,907.83	104,261	113,112	64,796	19.87	3,261
1982	169,589.99	121,257	131,551	38,039	18.04	2,109
1983	35,882.05	25,404	27,561	8,321	18.25	456
1984	81,827.28	57,328	62,195	19,633	18.48	1,062
1985	180,703.83	125,210	135,839	44,864	18.73	2,395
1986	196,405.01	133,673	145,021	51,384	19.36	2,654
1987	146,666.57	98,589	106,958	39,708	19.63	2,023
1988	154,751.03	102,646	111,360	43,391	19.92	2,178
1989	334,794.62	218,989	237,579	97,215	20.23	4,805
1990	136,874.06	88,202	95,690	41,184	20.55	2,004
1991	193,603.84	122,822	133,249	60,355	20.89	2,889
1992	282,847.84	176,469	191,450	91,398	21.25	4,301
1993	86,549.01	53,357	57,887	28,662	21.31	1,345
1994	181,236.28	109,684	118,995	62,241	21.69	2,870
1995	396,859.59	235,496	255,488	141,372	22.10	6,397
1996	818,778.06	475,874	516,272	302,506	22.52	13,433
1997	294,580.35	168,412	182,709	111,871	22.66	4,937
1998	503,734.26	281,436	305,328	198,407	23.10	8,589
1999	146,537.73	80,303	87,120	59,418	23.30	2,550
2000	646,411.98	346,994	376,451	269,961	23.51	11,483
2001	422,720.36	220,829	239,576	183,145	24.00	7,631
2002	260,599.71	132,906	144,189	116,411	24.26	4,798
2003	2,201,997.80	1,094,613	1,187,537	1,014,461	24.53	41,356
2004	1,205,552.54	583,005	632,498	573,055	24.83	23,079
2005	890,815.79	418,238	453,743	437,073	25.14	17,386
2006	866,210.85	393,953	427,397	438,814	25.48	17,222

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2007	738,069.37	325,784	353,441	384,629	25.62	15,013
2008	1,439,668.23	617,618	670,049	769,619	25.95	29,658
2009	547,413.67	226,848	246,106	301,308	26.14	11,527
2010	582,286.06	232,332	252,055	330,231	26.36	12,528
2011	2,477,358.89	944,369	1,024,539	1,452,820	26.79	54,230
2012	2,428,744.75	884,549	959,640	1,469,104	27.06	54,291
2013	962,946.24	335,105	363,553	599,393	27.17	22,061
2014	1,511,199.24	497,789	540,047	971,152	27.48	35,340
2015	5,050,043.29	1,571,573	1,704,987	3,345,056	27.66	120,935
2016	3,449,761.90	1,003,881	1,089,103	2,360,659	28.02	84,249
2017	3,140,867.77	850,861	923,093	2,217,775	28.26	78,478
2018	1,745,197.44	437,696	474,853	1,270,344	28.38	44,762
2019	5,079,854.70	1,161,255	1,259,837	3,820,018	28.68	133,194
2020	3,169,317.14	653,513	708,991	2,460,326	28.87	85,221
2021	7,820,554.35	1,433,508	1,555,202	6,265,353	28.96	216,345
2022	8,132,417.22	1,293,054	1,402,824	6,729,593	29.10	231,257
2023	8,098,609.99	1,078,735	1,170,311	6,928,299	29.28	236,622
2024	2,925,199.98	311,241	337,663	2,587,537	29.39	88,041
2025	4,329,866.95	338,596	367,340	3,962,527	29.45	134,551
2026	17,651,752.86	857,875	930,702	16,721,051	29.36	569,518
2027	20,112,433.77	337,889	366,573	19,745,861	29.18	676,692
	113,656,780.98	22,249,537	24,137,444	89,519,337		3,147,582
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1929	58.99	59	59			
1930	109.86	110	110			
1932	197.27	196	197			
1952	2,315.61	1,940	2,042	273	7.79	35
1953	1,154.21	958	1,009	146	8.18	18
1954	1,177.60	967	1,018	160	8.57	19
1955	8,967.15	7,293	7,678	1,289	8.96	144
1956	486.82	392	413	74	9.36	8
1957	72,929.07	58,116	61,186	11,743	9.75	1,204
1958	56,529.32	44,576	46,931	9,598	10.15	946
1959	12,760.45	9,956	10,482	2,278	10.55	216
1960	32,441.28	25,041	26,364	6,077	10.95	555
1961	23,693.17	18,091	19,047	4,646	11.35	409

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RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1962	27,285.62	20,601	21,689	5,596	11.76	476
1963	57,297.23	42,782	45,042	12,255	12.16	1,008
1964	58,168.52	42,935	45,203	12,965	12.57	1,031
1965	114,686.31	83,673	88,093	26,593	12.98	2,049
1966	92,967.05	67,013	70,553	22,414	13.40	1,673
1967	109,601.41	78,068	82,192	27,409	13.81	1,985
1968	157,689.08	110,941	116,802	40,887	14.23	2,873
1969	418,328.98	290,651	306,006	112,323	14.65	7,667
1970	355,387.43	243,810	256,691	98,697	15.07	6,549
1971	176,179.95	119,325	125,629	50,551	15.49	3,263
1972	61,628.64	41,188	43,364	18,265	15.92	1,147
1973	159,414.88	105,115	110,668	48,747	16.35	2,981
1974	60,062.76	39,066	41,130	18,933	16.78	1,128
1975	27,992.71	17,956	18,905	9,088	17.21	528
1976	50,057.41	31,651	33,323	16,734	17.65	948
1977	212,544.19	132,441	139,438	73,106	18.09	4,041
1978	8,167.49	5,015	5,280	2,888	18.53	156
1979	28,285.21	17,107	18,011	10,274	18.97	542
1980	113,240.40	67,426	70,988	42,252	19.42	2,176
1981	454,217.40	266,190	280,253	173,964	19.87	8,755
1982	328,461.18	234,850	247,257	81,204	18.04	4,501
1983	224,162.32	158,707	167,092	57,071	18.25	3,127
1984	56,050.23	39,269	41,344	14,707	18.48	796
1985	104,177.50	72,185	75,999	28,179	18.73	1,504
1986	132,972.60	90,501	95,282	37,690	19.36	1,947
1987	261,536.66	175,805	185,093	76,444	19.63	3,894
1988	119,726.99	79,415	83,611	36,116	19.92	1,813
1989	200,231.87	130,972	137,891	62,341	20.23	3,082
1990	106,206.22	68,439	72,055	34,152	20.55	1,662
1991	79,674.10	50,545	53,215	26,459	20.89	1,267
1992	147,510.95	92,032	96,894	50,617	21.25	2,382
1993	179,020.01	110,366	116,197	62,823	21.31	2,948
1994	425,039.96	257,234	270,824	154,216	21.69	7,110
1995	292,571.10	173,612	182,784	109,787	22.10	4,968
1996	198,223.97	115,208	121,294	76,929	22.52	3,416
1997	425,406.69	243,205	256,054	169,353	22.66	7,474
1998	447,881.80	250,232	263,452	184,430	23.10	7,984
1999	143,231.13	78,491	82,638	60,593	23.30	2,601
2000	130,762.40	70,193	73,901	56,861	23.51	2,419
2001	714,509.34	373,260	392,980	321,530	24.00	13,397
2002	109,282.86	55,734	58,678	50,604	24.26	2,086

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2003	117,916.31	58,616	61,713	56,204	24.53	2,291
2004	493,422.57	238,619	251,225	242,197	24.83	9,754
2005	285,542.68	134,062	141,145	144,398	25.14	5,744
2006	251,220.33	114,255	120,291	130,929	25.48	5,139
2007	891,848.00	393,662	414,459	477,389	25.62	18,633
2008	791,704.54	339,641	357,584	434,120	25.95	16,729
2009	101,130.74	41,909	44,123	57,008	26.14	2,181
2010	91,083.87	36,342	38,262	52,822	26.36	2,004
2011	1,500,685.84	572,061	602,283	898,403	26.79	33,535
2012	452,577.39	164,829	173,537	279,040	27.06	10,312
2013	22,506.02	7,832	8,246	14,260	27.17	525
2014	3,021,456.72	995,268	1,047,849	1,973,608	27.48	71,820
2015	1,485,145.91	462,177	486,594	998,552	27.66	36,101
2016	1,043,371.30	303,621	319,661	723,710	28.02	25,828
2017	1,884,811.91	510,596	537,571	1,347,241	28.26	47,673
2018	10,737,689.23	2,693,012	2,835,285	7,902,404	28.38	278,450
2019	4,123,000.39	942,518	992,312	3,130,689	28.68	109,159
2020	4,236,788.97	873,626	919,780	3,317,009	28.87	114,895
2021	2,162,596.83	396,404	417,346	1,745,251	28.96	60,264
2022	7,502,269.50	1,192,861	1,255,880	6,246,389	29.10	214,653
2023	2,211,966.72	294,634	310,200	1,901,767	29.28	64,951
2024	1,666,979.06	177,367	186,737	1,480,242	29.39	50,365
2025	1,841,128.84	143,976	151,582	1,689,547	29.45	57,370
2026	2,560,431.79	124,437	131,011	2,429,421	29.36	82,746
2027	8,365,517.67	140,541	147,966	8,217,552	29.18	281,616
	65,625,456.48	16,263,770	17,122,975	48,502,481		1,737,646
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	49.71	50	50			
1911	74.43	74	74			
1922	239.65	240	240			
1926	221.61	222	222			
1927	195.87	196	196			
1928	1,791.77	1,792	1,792			
1929	55.23	55	55			
1930	19.49	19	19			
1931	24.36	24	24			

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ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1932	102.73	102	103			
1934	267.54	262	268			
1935	272.68	265	273			
1936	438.73	423	439			
1937	1,079.14	1,032	1,079			
1938	450.67	427	451			
1939	436.02	410	436			
1940	99.67	93	100			
1941	242.91	225	243			
1945	104.32	93	102	2	5.10	
1947	482.97	424	467	16	5.86	3
1948	531.67	462	509	22	6.25	4
1949	69.62	60	66	3	6.63	
1950	50.06	43	47	3	7.02	
1951	42.77	36	40	3	7.40	
1952	318.99	267	294	25	7.79	3
1953	316.09	262	289	27	8.18	3
1954	1,075.72	884	974	101	8.57	12
1955	520.36	423	466	54	8.96	6
1956	7,497.08	6,035	6,651	846	9.36	90
1957	7,332.27	5,843	6,440	893	9.75	92
1958	2,897.56	2,285	2,518	379	10.15	37
1959	1,717.28	1,340	1,477	240	10.55	23
1960	4,272.61	3,298	3,635	638	10.95	58
1961	4,315.00	3,295	3,631	684	11.35	60
1962	3,909.96	2,952	3,253	657	11.76	56
1963	7,664.12	5,723	6,307	1,357	12.16	112
1964	7,645.51	5,643	6,219	1,426	12.57	113
1965	25,905.21	18,900	20,830	5,075	12.98	391
1966	16,855.68	12,150	13,391	3,465	13.40	259
1967	8,124.44	5,787	6,378	1,746	13.81	126
1968	11,937.64	8,399	9,257	2,681	14.23	188
1969	12,135.92	8,432	9,293	2,843	14.65	194
1970	8,580.64	5,887	6,488	2,092	15.07	139
1971	19,708.17	13,348	14,711	4,997	15.49	323
1972	17,108.62	11,434	12,602	4,507	15.92	283
1973	16,639.43	10,972	12,092	4,547	16.35	278
1974	41,849.98	27,220	30,000	11,850	16.78	706
1975	7,680.18	4,927	5,430	2,250	17.21	131
1976	24,671.33	15,599	17,192	7,479	17.65	424
1977	9,882.81	6,158	6,787	3,096	18.09	171

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1978	39,884.03	24,487	26,988	12,896	18.53	696
1979	28,801.79	17,419	19,198	9,604	18.97	506
1980	37,687.35	22,440	24,732	12,956	19.42	667
1981	102,928.95	60,320	66,480	36,449	19.87	1,834
1982	85,222.70	60,934	67,157	18,066	18.04	1,001
1983	60,124.00	42,568	46,915	13,209	18.25	724
1984	49,877.97	34,945	38,514	11,364	18.48	615
1985	94,773.89	65,669	72,375	22,399	18.73	1,196
1986	84,708.25	57,652	63,539	21,169	19.36	1,093
1987	80,035.16	53,800	59,294	20,741	19.63	1,057
1988	72,408.40	48,028	52,933	19,476	19.92	978
1989	107,349.32	70,217	77,388	29,962	20.23	1,481
1990	75,507.91	48,657	53,626	21,882	20.55	1,065
1991	127,436.23	80,846	89,102	38,334	20.89	1,835
1992	138,776.48	86,583	95,425	43,352	21.25	2,040
1993	101,417.48	62,524	68,909	32,509	21.31	1,526
1994	129,406.90	78,317	86,315	43,092	21.69	1,987
1995	231,900.19	137,610	151,663	80,238	22.10	3,631
1996	173,392.74	100,776	111,067	62,326	22.52	2,768
1997	159,813.59	91,365	100,695	59,118	22.66	2,609
1998	254,772.84	142,342	156,878	97,895	23.10	4,238
1999	131,184.69	71,889	79,230	51,954	23.30	2,230
2000	465,714.05	249,995	275,524	190,190	23.51	8,090
2001	173,169.51	90,464	99,702	73,467	24.00	3,061
2002	361,735.82	184,485	203,324	158,411	24.26	6,530
2003	209,982.99	104,383	115,043	94,940	24.53	3,870
2004	271,615.73	131,353	144,767	126,849	24.83	5,109
2005	431,862.09	202,759	223,465	208,397	25.14	8,289
2006	203,910.13	92,738	102,208	101,702	25.48	3,991
2007	374,177.27	165,162	182,028	192,149	25.62	7,500
2008	401,445.70	172,220	189,807	211,639	25.95	8,156
2009	344,264.50	142,663	157,232	187,033	26.14	7,155
2010	114,966.24	45,872	50,556	64,410	26.36	2,443
2011	718,051.26	273,721	301,673	416,378	26.79	15,542
2012	333,903.78	121,608	134,027	199,877	27.06	7,386
2013	889,223.41	309,450	341,051	548,173	27.17	20,176
2014	1,763,951.89	581,046	640,382	1,123,570	27.48	40,887
2015	2,782,124.24	865,797	954,212	1,827,913	27.66	66,085
2016	903,486.41	262,915	289,764	613,723	28.02	21,903
2017	647,172.99	175,319	193,222	453,951	28.26	16,063
2018	232,448.08	58,298	64,251	168,197	28.38	5,927

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2019	407,412.22	93,134	102,645	304,767	28.68	10,626
2020	1,606,057.88	331,169	364,988	1,241,070	28.87	42,988
2021	4,767,204.83	873,829	963,064	3,804,141	28.96	131,358
2022	3,521,302.12	559,887	617,062	2,904,240	29.10	99,802
2023	2,356,682.74	313,910	345,966	2,010,716	29.28	68,672
2024	4,669,432.91	496,828	547,564	4,121,869	29.39	140,247
2025	1,535,006.05	120,037	132,295	1,402,711	29.45	47,630
2026	7,223,192.87	351,047	386,896	6,836,297	29.36	232,844
2027	9,421,129.31	158,275	174,438	9,246,691	29.18	316,885
	49,775,944.10	9,182,244	10,119,476	39,656,468		1,389,277
	229,058,181.56	47,695,551	51,379,895	177,678,286		6,274,505
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.3	2.74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	1,330.58	1,187	1,322	8	4.86	2
1956	21,290.16	18,750	20,885	405	5.37	75
1957	5,372.45	4,700	5,235	137	5.63	24
1958	8,518.07	7,401	8,244	274	5.90	46
1959	4,392.86	3,790	4,222	171	6.18	28
1960	27,087.71	23,199	25,840	1,247	6.46	193
1961	1,916.00	1,629	1,814	102	6.74	15
1962	1,339.47	1,130	1,259	81	7.03	12
1963	30.71	26	29	2	7.33	
1965	41,595.76	34,266	38,167	3,428	7.93	432
1966	19,579.16	15,994	17,815	1,764	8.24	214
1967	14,375.52	11,641	12,966	1,409	8.56	165
1968	818.29	657	732	86	8.88	10
1969	15,932.36	12,671	14,114	1,819	9.21	198
1970	553.00	436	486	67	9.54	7
1972	36,690.90	28,342	31,569	5,122	10.24	500
1973	38,195.02	29,189	32,512	5,683	10.61	536
1974	19,018.54	14,378	16,015	3,004	10.98	274
1975	25,329.73	18,935	21,091	4,239	11.36	373
1976	12,818.60	9,469	10,547	2,272	11.76	193
1977	148.01	108	120	28	12.16	2
1978	4,242.67	3,058	3,406	837	12.57	67
1979	1,542.38	1,097	1,222	320	13.00	25
1980	4,638.03	3,253	3,623	1,015	13.44	76
1981	80,176.22	55,428	61,739	18,438	13.89	1,327
1982	141,945.62	110,476	123,054	18,892	12.89	1,466
1983	6,800.47	5,236	5,832	968	13.22	73
1984	199,926.07	152,184	169,511	30,416	13.57	2,241
1985	433,461.53	325,963	363,075	70,387	13.93	5,053
1986	265,735.11	196,219	218,559	47,176	14.61	3,229
1987	791,585.85	576,670	642,325	149,260	15.00	9,951
1988	18,764.80	13,479	15,014	3,751	15.39	244
1989	37,807.02	26,752	29,798	8,009	15.81	507
1990	128,484.87	89,503	99,693	28,792	16.22	1,775
1991	257,739.07	176,577	196,681	61,058	16.66	3,665
1992	198,243.74	133,478	148,675	49,569	17.10	2,899
1993	32,985.36	21,803	24,285	8,700	17.56	495
1994	6,197.62	4,019	4,477	1,721	18.03	95
1995	265,285.40	168,536	187,724	77,561	18.51	4,190
1996	390,043.61	242,568	270,185	119,859	19.00	6,308
1998	8,401.63	4,989	5,557	2,845	20.01	142

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
2003	278,252.13	145,081	161,599	116,653	22.26	5,240
2009	23,277.53	9,860	10,983	12,295	25.17	488
2014	78,923.32	26,108	29,080	49,843	27.31	1,825
2016	168,831.19	48,927	54,497	114,334	28.18	4,057
2017	32,073.62	8,653	9,638	22,435	28.41	790
2019	90,422.23	20,444	22,772	67,651	29.09	2,326
2020	191,930.65	39,154	43,612	148,319	29.26	5,069
2021	1,737,045.60	313,884	349,621	1,387,425	29.47	47,079
2022	16,273,209.43	2,551,639	2,842,150	13,431,059	29.59	453,905
2023	11,855,743.76	1,562,587	1,740,492	10,115,252	29.63	341,385
2024	909,861.73	96,809	107,831	802,031	29.39	27,289
2025	14,466,646.64	1,150,098	1,281,040	13,185,607	28.95	455,461
	49,676,557.80	8,522,430	9,492,732	40,183,826		1,392,041
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,371	14,451	2,329	6.46	361
1962	29,310.05	24,731	24,869	4,441	7.03	632
1963	28,716.91	24,039	24,173	4,544	7.33	620
1964	1,610.71	1,338	1,345	265	7.62	35
1965	15,073.47	12,417	12,486	2,587	7.93	326
1966	113,790.28	92,954	93,472	20,318	8.24	2,466
1967	4,284.76	3,470	3,489	795	8.56	93
1968	122,380.44	98,231	98,779	23,602	8.88	2,658
1969	114,417.87	91,000	91,507	22,910	9.21	2,488
1970	18,752.91	14,777	14,859	3,894	9.54	408
1971	13,464.24	10,505	10,564	2,901	9.89	293
1972	2,349.36	1,815	1,825	524	10.24	51
1974	21,308.55	16,109	16,199	5,110	10.98	465
1975	37,036.13	27,687	27,841	9,195	11.36	809
1977	2,043.72	1,491	1,499	544	12.16	45
1978	2,934.41	2,115	2,127	808	12.57	64
1979	1,353.24	962	967	386	13.00	30
1980	47,010.45	32,970	33,154	13,857	13.44	1,031
1981	687,198.17	475,081	477,730	209,468	13.89	15,080
1982	114,036.20	88,754	89,249	24,787	12.89	1,923
1983	6,538.51	5,035	5,063	1,475	13.22	112
1984	1,848.56	1,407	1,415	434	13.57	32

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1985	33,053.50	24,856	24,995	8,059	13.93	579
1986	796.80	588	591	206	14.61	14
1987	900.93	656	660	241	15.00	16
1988	228,712.92	164,284	165,200	63,513	15.39	4,127
1989	5,767.35	4,081	4,104	1,664	15.81	105
1990	8,208.45	5,718	5,750	2,459	16.22	152
1991	15,153.04	10,381	10,439	4,714	16.66	283
1992	1,292.66	870	875	418	17.10	24
1993	49,169.36	32,501	32,682	16,487	17.56	939
1994	82,378.57	53,414	53,712	28,667	18.03	1,590
1995	42,532.19	27,021	27,172	15,360	18.51	830
1996	44,580.63	27,725	27,880	16,701	19.00	879
1997	515,665.73	313,525	315,273	200,392	19.50	10,277
1998	118,063.23	70,106	70,497	47,566	20.01	2,377
1999	58,548.09	33,905	34,094	24,454	20.53	1,191
2000	69,703.96	39,508	39,728	29,976	20.83	1,439
2001	173,986.69	95,901	96,436	77,551	21.37	3,629
2002	184,888.86	98,971	99,523	85,366	21.92	3,894
2003	175,733.00	91,627	92,138	83,595	22.26	3,755
2004	75,956.41	38,320	38,534	37,423	22.83	1,639
2005	48,587.58	23,677	23,809	24,779	23.41	1,058
2006	162,733.73	76,778	77,206	85,528	23.79	3,595
2007	9,461.70	4,292	4,316	5,146	24.39	211
2008	460,995.77	203,161	204,294	256,702	24.75	10,372
2009	53,996.90	22,873	23,001	30,996	25.17	1,231
2010	265,809.52	107,919	108,521	157,289	25.60	6,144
2011	1,348,202.00	522,833	525,749	822,453	26.05	31,572
2012	963,681.06	355,502	357,485	606,196	26.52	22,858
2013	309,369.28	108,094	108,697	200,672	27.00	7,432
2014	7,850,809.11	2,597,048	2,611,531	5,239,278	27.31	191,845
2015	784,772.22	243,279	244,636	540,136	27.82	19,415
2018	1.37			1	28.81	
2019	2,147,672.02	485,589	488,297	1,659,375	29.09	57,043
2020	350,661.95	71,535	71,934	278,728	29.26	9,526
2021	214,987.16	38,848	39,065	175,923	29.47	5,970
2022	5,163,458.24	809,630	814,145	4,349,313	29.59	146,986
2023	4,648,863.73	612,720	616,137	4,032,727	29.63	136,103
2024	667,067.84	70,976	71,372	595,696	29.39	20,269
2025	820,714.65	65,247	65,611	755,104	28.95	26,083
	29,559,177.51	8,595,218	8,643,152	20,916,026		765,474

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	266.15	237	229	37	4.86	8
1956	1,419.60	1,250	1,208	211	5.37	39
1958	1,154.96	1,004	971	184	5.90	31
1959	352.50	304	294	59	6.18	10
1960	3,229.10	2,766	2,674	555	6.46	86
1965	2,958.56	2,437	2,356	603	7.93	76
1966	3,788.99	3,095	2,992	797	8.24	97
1967	2,785.64	2,256	2,181	605	8.56	71
1969	2,147.66	1,708	1,651	497	9.21	54
1971	481.68	376	363	118	9.89	12
1972	1,415.71	1,094	1,058	358	10.24	35
1973	1,983.52	1,516	1,465	518	10.61	49
1974	1,411.62	1,067	1,031	380	10.98	35
1976	3,626.30	2,679	2,590	1,037	11.76	88
1978	10,681.17	7,698	7,441	3,240	12.57	258
1980	703.40	493	477	227	13.44	17
1981	2,492.78	1,723	1,666	827	13.89	60
1987	1,548.80	1,128	1,090	458	15.00	31
1988	1,790.48	1,286	1,243	547	15.39	36
1991	417.27	286	276	141	16.66	8
1994	551.52	358	346	205	18.03	11
2012	1,055.35	389	376	679	26.52	26
2013	422.81	148	143	280	27.00	10
2019	181,294.79	40,991	39,624	141,670	29.09	4,870
2023	653,815.24	86,173	83,300	570,515	29.63	19,255
2024	1,265,047.41	134,601	130,114	1,134,934	29.39	38,616
2025	397,245.69	31,581	30,528	366,718	28.95	12,667
	2,544,088.70	328,644	317,688	2,226,401		76,556
	81,779,824.01	17,446,292	18,453,572	63,326,253		2,234,071

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.3 2.73

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1956	6,719.26	6,221	5,762	958	3.34	287
1957	21,354.26	19,632	18,183	3,172	3.63	874
1958	38,555.99	35,197	32,598	5,958	3.92	1,520
1959	83,456.20	75,648	70,063	13,393	4.21	3,181
1960	131,856.14	118,671	109,910	21,947	4.50	4,877
1961	158,279.13	141,432	130,990	27,289	4.79	5,697
1962	160,233.21	142,109	131,617	28,616	5.09	5,622
1963	194,676.01	171,401	158,747	35,929	5.38	6,678
1964	196,587.08	171,817	159,132	37,455	5.67	6,606
1965	253,972.90	220,278	204,015	49,958	5.97	8,368
1966	370,848.51	319,093	295,535	75,314	6.28	11,993
1967	350,536.57	299,204	277,114	73,423	6.59	11,142
1968	421,059.01	356,498	330,178	90,881	6.90	13,171
1969	452,872.37	380,214	352,143	100,729	7.22	13,951
1970	457,048.37	380,365	352,283	104,765	7.55	13,876
1971	518,830.59	427,864	396,275	122,555	7.89	15,533
1972	736,605.26	601,725	557,300	179,305	8.24	21,760
1973	923,649.67	747,334	692,159	231,491	8.59	26,949
1974	973,924.95	780,007	722,420	251,505	8.96	28,070
1975	643,371.78	509,834	472,193	171,178	9.34	18,327
1976	719,098.00	563,615	522,004	197,094	9.73	20,256
1977	1,399,983.70	1,084,833	1,004,741	395,243	10.13	39,017
1978	1,308,099.76	1,001,429	927,494	380,605	10.55	36,076
1979	2,431,557.77	1,838,793	1,703,037	728,521	10.97	66,410
1980	4,129,017.15	3,082,064	2,854,518	1,274,499	11.41	111,700
1981	4,215,394.32	3,104,385	2,875,191	1,340,203	11.86	113,002
1982	3,739,508.07	2,994,972	2,773,856	965,652	11.25	85,836
1983	2,784,269.53	2,205,420	2,042,596	741,674	11.61	63,882
1984	2,965,280.70	2,321,222	2,149,848	815,432	12.00	67,953
1985	3,426,473.23	2,649,349	2,453,750	972,723	12.39	78,509
1986	3,717,344.30	2,836,705	2,627,274	1,090,071	12.81	85,095
1987	4,426,882.11	3,332,114	3,086,107	1,340,775	13.22	101,420
1988	5,722,308.90	4,222,492	3,910,749	1,811,560	13.94	129,954
1989	8,174,341.27	5,941,111	5,502,484	2,671,857	14.38	185,804
1990	9,114,673.14	6,518,814	6,037,536	3,077,137	14.83	207,494
1991	8,292,948.42	5,831,601	5,401,059	2,891,889	15.30	189,012
1992	8,300,522.71	5,734,831	5,311,433	2,989,089	15.77	189,543
1993	5,697,877.97	3,864,301	3,579,003	2,118,875	16.25	130,392
1994	11,268,540.74	7,493,580	6,940,336	4,328,205	16.75	258,400
1995	12,011,367.79	7,824,205	7,246,551	4,764,817	17.26	276,061
1996	10,004,393.06	6,377,801	5,906,934	4,097,459	17.77	230,583

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1997	11,217,742.04	6,990,897	6,474,765	4,742,977	18.29	259,321
1998	8,993,850.35	5,471,859	5,067,876	3,925,974	18.83	208,496
1999	9,169,222.36	5,439,183	5,037,613	4,131,609	19.37	213,299
2000	9,647,420.73	5,573,315	5,161,842	4,485,579	19.92	225,180
2001	9,536,565.42	5,357,642	4,962,092	4,574,473	20.48	223,363
2002	10,045,539.34	5,503,951	5,097,599	4,947,940	20.83	237,539
2003	7,927,977.77	4,210,549	3,899,688	4,028,290	21.41	188,150
2004	10,886,702.51	5,593,588	5,180,618	5,706,084	22.00	259,367
2005	9,157,916.98	4,544,158	4,208,667	4,949,250	22.59	219,090
2006	9,973,677.27	4,768,415	4,416,367	5,557,310	23.20	239,539
2007	9,928,318.77	4,583,905	4,245,479	5,682,839	23.61	240,696
2008	13,044,454.01	5,825,653	5,395,550	7,648,904	24.17	316,463
2009	13,300,769.96	5,708,690	5,287,222	8,013,548	24.60	325,754
2010	13,762,429.54	5,635,715	5,219,635	8,542,794	25.24	338,463
2011	21,128,720.92	8,227,524	7,620,093	13,508,628	25.87	522,173
2012	31,112,341.93	11,524,011	10,673,203	20,439,138	26.34	775,973
2013	40,356,553.18	14,100,580	13,059,547	27,297,007	27.00	1,011,000
2014	39,290,804.56	12,942,391	11,986,866	27,303,939	27.48	993,593
2015	41,063,626.31	12,680,448	11,744,262	29,319,365	27.98	1,047,869
2016	44,799,091.62	12,879,739	11,928,839	32,870,252	28.50	1,153,342
2017	42,507,936.08	11,290,108	10,456,569	32,051,367	29.03	1,104,077
2018	48,555,031.07	11,808,584	10,936,767	37,618,264	29.56	1,272,607
2019	64,414,609.52	14,235,629	13,184,625	51,229,984	29.96	1,709,946
2020	56,346,647.86	11,111,559	10,291,202	46,055,445	30.52	1,509,025
2021	74,284,274.71	12,895,750	11,943,668	62,340,607	30.95	2,014,236
2022	94,230,317.13	14,096,855	13,056,097	81,174,220	31.26	2,596,744
2023	98,356,804.78	12,255,258	11,350,463	87,006,342	31.60	2,753,365
2024	65,754,674.05	6,509,713	6,029,107	59,725,567	31.84	1,875,803
2025	54,558,115.44	3,982,742	3,688,700	50,869,416	31.75	1,602,186
2026	86,463,888.98	3,942,753	3,651,663	82,812,226	31.39	2,638,172
2027	93,307,632.13	1,548,907	1,434,553	91,873,080	29.62	3,101,725
	1,264,067,977.22	337,968,252	313,016,354	951,051,623		34,061,437
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1939	384.08	384	384			
1940	2,139.27	2,139	2,139			
1941	2,837.99	2,838	2,838			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1942	2,181.77	2,182	2,182			
1943	1,821.67	1,822	1,822			
1944	3,308.00	3,291	3,250	58	0.23	58
1945	5,915.21	5,870	5,798	118	0.34	118
1946	10,696.95	10,557	10,427	270	0.59	270
1947	12,065.18	11,837	11,691	374	0.85	374
1948	15,282.13	14,902	14,718	564	1.12	504
1949	14,185.83	13,751	13,581	604	1.38	438
1950	20,803.17	20,040	19,793	1,010	1.65	612
1951	16,140.97	15,452	15,261	880	1.92	458
1952	1,241,690.33	1,180,984	1,166,414	75,276	2.20	34,216
1953	13,193.12	12,466	12,312	881	2.48	355
1954	19,065.53	17,892	17,671	1,394	2.77	503
1955	32,763.29	30,543	30,166	2,597	3.05	851
1956	38,242.48	35,404	34,967	3,275	3.34	981
1957	53,797.11	49,457	48,847	4,950	3.63	1,364
1958	79,909.24	72,948	72,048	7,861	3.92	2,005
1959	128,194.59	116,201	114,767	13,427	4.21	3,189
1960	113,536.12	102,183	100,922	12,614	4.50	2,803
1961	137,929.35	123,248	121,727	16,202	4.79	3,382
1962	252,714.65	224,130	221,365	31,350	5.09	6,159
1963	320,743.26	282,395	278,911	41,832	5.38	7,775
1964	436,305.21	381,331	376,627	59,679	5.67	10,525
1965	523,664.06	454,190	448,587	75,077	5.97	12,576
1966	583,126.71	501,746	495,556	87,571	6.28	13,944
1967	687,444.18	586,775	579,536	107,908	6.59	16,375
1968	895,620.49	758,295	748,940	146,681	6.90	21,258
1969	951,363.90	798,727	788,873	162,491	7.22	22,506
1970	1,097,479.19	913,344	902,076	195,403	7.55	25,881
1971	372,602.01	307,274	303,483	69,119	7.89	8,760
1972	630,569.58	515,106	508,751	121,818	8.24	14,784
1973	1,185,260.75	959,006	947,175	238,086	8.59	27,717
1974	1,224,110.63	980,378	968,283	255,828	8.96	28,552
1975	1,049,914.63	831,994	821,730	228,185	9.34	24,431
1976	1,276,495.06	1,000,491	988,148	288,347	9.73	29,635
1977	1,632,149.44	1,264,736	1,249,133	383,017	10.13	37,810
1978	1,246,494.80	954,267	942,494	304,001	10.55	28,815
1979	1,578,138.40	1,193,420	1,178,697	399,442	10.97	36,412
1980	1,796,880.34	1,341,263	1,324,716	472,165	11.41	41,382
1981	1,652,134.02	1,216,698	1,201,688	450,446	11.86	37,980
1982	1,357,856.31	1,087,507	1,074,090	283,766	11.25	25,224

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1983	1,044,979.07	827,728	817,516	227,463	11.61	19,592
1984	1,489,499.90	1,165,981	1,151,596	337,904	12.00	28,159
1985	1,911,550.75	1,478,011	1,459,777	451,774	12.39	36,463
1986	2,401,416.56	1,832,521	1,809,913	591,503	12.81	46,175
1987	3,190,742.81	2,401,672	2,372,042	818,700	13.22	61,929
1988	4,253,001.39	3,138,290	3,099,573	1,153,429	13.94	82,742
1989	4,038,903.45	2,935,475	2,899,260	1,139,644	14.38	79,252
1990	4,450,322.97	3,182,871	3,143,604	1,306,719	14.83	88,113
1991	3,269,413.50	2,299,052	2,270,689	998,725	15.30	65,276
1992	4,052,792.61	2,800,074	2,765,529	1,287,263	15.77	81,627
1993	4,295,124.84	2,912,954	2,877,017	1,418,108	16.25	87,268
1994	4,381,894.77	2,913,960	2,878,010	1,503,884	16.75	89,784
1995	5,041,564.07	3,284,075	3,243,559	1,798,005	17.26	104,172
1996	4,928,320.96	3,141,805	3,103,044	1,825,277	17.77	102,717
1997	5,982,139.44	3,728,069	3,682,076	2,300,064	18.29	125,755
1998	5,438,933.88	3,309,047	3,268,223	2,170,711	18.83	115,279
1999	3,945,418.51	2,340,422	2,311,548	1,633,870	19.37	84,351
2000	3,164,333.52	1,828,035	1,805,482	1,358,851	19.92	68,215
2001	5,806,826.27	3,262,275	3,222,028	2,584,798	20.48	126,211
2002	4,855,515.87	2,660,337	2,627,516	2,228,000	20.83	106,961
2003	5,219,265.37	2,771,952	2,737,754	2,481,511	21.41	115,904
2004	11,210,580.84	5,759,996	5,688,935	5,521,646	22.00	250,984
2005	7,266,511.55	3,605,643	3,561,160	3,705,351	22.59	164,026
2006	4,264,952.85	2,039,074	2,013,918	2,251,035	23.20	97,027
2007	5,863,053.81	2,706,972	2,673,576	3,189,478	23.61	135,090
2008	6,289,875.28	2,809,058	2,774,403	3,515,473	24.17	145,448
2009	6,292,971.17	2,700,943	2,667,621	3,625,350	24.60	147,372
2010	4,181,769.32	1,712,435	1,691,309	2,490,461	25.24	98,671
2011	7,257,681.83	2,826,141	2,791,275	4,466,407	25.87	172,648
2012	9,139,085.67	3,385,117	3,343,355	5,795,731	26.34	220,035
2013	9,037,947.49	3,157,859	3,118,900	5,919,047	27.00	219,224
2014	9,590,136.43	3,158,991	3,120,018	6,470,118	27.48	235,448
2015	13,926,731.87	4,300,575	4,247,519	9,679,213	27.98	345,933
2016	15,467,379.69	4,446,872	4,392,011	11,075,369	28.50	388,609
2017	17,004,757.49	4,516,464	4,460,744	12,544,013	29.03	432,105
2018	19,258,794.76	4,683,739	4,625,956	14,632,839	29.56	495,022
2019	23,390,465.60	5,169,293	5,105,519	18,284,946	29.96	610,312
2020	18,061,119.87	3,561,653	3,517,713	14,543,407	30.52	476,521
2021	32,061,773.49	5,565,924	5,497,257	26,564,516	30.95	858,304
2022	28,927,514.19	4,327,556	4,274,167	24,653,347	31.26	788,655
2023	25,222,730.33	3,142,752	3,103,980	22,118,751	31.60	699,960

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2024	16,332,923.71	1,616,959	1,597,011	14,735,913	31.84	462,811
2025	19,118,094.07	1,395,621	1,378,403	17,739,691	31.75	558,730
2026	29,412,259.48	1,341,199	1,324,653	28,087,607	31.39	894,795
2027	29,107,041.21	483,177	477,216	28,629,825	29.62	966,571
	473,565,263.51	151,028,083	149,164,960	324,400,304		12,111,228
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1974	3,353.44	2,686	2,419	934	8.96	104
1975	20,563.92	16,296	14,678	5,886	9.34	630
1976	17,048.39	13,362	12,036	5,013	9.73	515
1977	28,770.21	22,294	20,081	8,689	10.13	858
1978	30,273.46	23,176	20,875	9,398	10.55	891
1979	82,447.92	62,349	56,160	26,288	10.97	2,396
1980	207,705.75	155,040	139,649	68,056	11.41	5,965
1981	215,260.85	158,527	142,790	72,471	11.86	6,111
1982	189,219.03	151,546	136,502	52,717	11.25	4,686
1983	281,499.80	222,976	200,841	80,658	11.61	6,947
1984	372,589.86	291,663	262,710	109,880	12.00	9,157
1985	433,867.11	335,466	302,165	131,703	12.39	10,630
1986	573,395.53	437,558	394,122	179,274	12.81	13,995
1987	563,942.65	424,480	382,342	181,600	13.22	13,737
1988	959,952.51	708,349	638,032	321,921	13.94	23,093
1989	1,031,318.05	749,562	675,154	356,165	14.38	24,768
1990	916,736.70	655,650	590,564	326,173	14.83	21,994
1991	1,433,328.09	1,007,916	907,861	525,467	15.30	34,344
1992	1,061,216.27	733,194	660,410	400,806	15.77	25,416
1993	1,898,816.68	1,287,777	1,159,940	738,876	16.25	45,469
1994	2,199,471.24	1,462,648	1,317,452	882,019	16.75	52,658
1995	2,138,597.23	1,393,082	1,254,792	883,805	17.26	51,205
1996	2,200,387.48	1,402,747	1,263,497	936,890	17.77	52,723
1997	2,516,493.99	1,568,279	1,412,597	1,103,897	18.29	60,355
1998	2,256,184.90	1,372,663	1,236,400	1,019,785	18.83	54,157
1999	2,007,921.02	1,191,099	1,072,859	935,062	19.37	48,274
2000	2,099,318.97	1,212,777	1,092,386	1,006,933	19.92	50,549
2001	1,708,886.69	960,053	864,749	844,137	20.48	41,218
2002	2,185,382.63	1,197,371	1,078,509	1,106,874	20.83	53,138
2003	2,521,213.01	1,339,016	1,206,093	1,315,120	21.41	61,426

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2004	2,117,516.38	1,087,980	979,977	1,137,539	22.00	51,706
2005	2,223,998.00	1,103,548	994,000	1,229,998	22.59	54,449
2006	2,191,753.14	1,047,877	943,855	1,247,898	23.20	53,789
2007	2,404,867.35	1,110,327	1,000,106	1,404,762	23.61	59,499
2008	3,516,269.78	1,570,366	1,414,477	2,101,793	24.17	86,959
2009	2,969,010.44	1,274,299	1,147,800	1,821,210	24.60	74,033
2010	3,235,856.58	1,325,083	1,193,543	2,042,314	25.24	80,916
2011	5,781,201.39	2,251,200	2,027,725	3,753,476	25.87	145,090
2012	5,240,323.38	1,941,016	1,748,333	3,491,991	26.34	132,574
2013	6,838,363.02	2,389,324	2,152,138	4,686,225	27.00	173,564
2014	6,663,556.62	2,194,976	1,977,082	4,686,474	27.48	170,541
2015	6,334,820.82	1,956,193	1,762,003	4,572,818	27.98	163,432
2016	4,751,878.65	1,366,165	1,230,547	3,521,332	28.50	123,556
2017	5,079,396.42	1,349,088	1,215,165	3,864,231	29.03	133,112
2018	1,304,720.83	317,308	285,809	1,018,912	29.56	34,469
2019	5,667,904.16	1,252,607	1,128,262	4,539,643	29.96	151,523
2020	4,704,457.13	927,719	835,625	3,868,832	30.52	126,764
2021	8,606,528.07	1,494,093	1,345,775	7,260,753	30.95	234,596
2022	6,379,158.57	954,322	859,587	5,519,571	31.26	176,570
2023	6,558,382.78	817,174	736,054	5,822,329	31.60	184,251
2024	13,385,472.42	1,325,162	1,193,614	12,191,858	31.84	382,910
2025	6,678,128.75	487,503	439,109	6,239,020	31.75	196,505
2026	17,814,662.25	812,349	731,708	17,082,955	31.39	544,216
2027	37,166,973.52	616,972	555,726	36,611,248	29.62	1,236,031
	199,770,363.83	51,532,253	46,416,684	153,353,680		5,548,464
	1,937,403,604.56	540,528,588	508,597,998	1,428,805,607		51,721,129

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.6 2.67

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1954	46.95	47	47			
1955	1,024.03	1,024	1,024			
1956	1,502.46	1,502	1,502			
1957	1,450.97	1,451	1,451			
1958	2,423.78	2,424	2,424			
1959	2,683.06	2,683	2,683			
1960	3,386.06	3,386	3,386			
1961	4,507.09	4,483	4,507			
1962	5,677.60	5,611	5,678			
1963	6,049.46	5,937	6,049			
1964	7,478.00	7,285	7,478			
1965	7,290.28	7,047	7,290			
1966	7,263.60	6,967	7,264			
1967	19,320.57	18,381	19,321			
1968	43,561.27	41,105	43,561			
1969	43,028.03	40,267	43,028			
1970	38,173.58	35,417	38,174			
1971	16,574.67	15,244	16,575			
1972	16,299.88	14,860	16,300			
1973	33,231.39	30,028	33,151	80	3.47	23
1974	37,127.70	33,250	36,709	419	3.76	111
1975	31,209.23	27,698	30,579	630	4.05	156
1976	21,224.22	18,660	20,601	623	4.35	143
1977	28,412.39	24,750	27,324	1,088	4.64	234
1978	71,431.25	61,609	68,017	3,414	4.95	690
1979	87,726.33	74,933	82,727	4,999	5.25	952
1980	374,532.78	316,585	349,515	25,018	5.57	4,492
1981	220,362.35	184,309	203,480	16,882	5.89	2,866
1982	137,012.57	121,516	134,156	2,857	5.77	495
1983	15,344.36	13,445	14,843	501	6.25	80
1984	78,622.00	68,346	75,455	3,167	6.50	487
1985	274,974.79	237,001	261,653	13,322	6.77	1,968
1986	176,563.23	150,767	166,449	10,114	7.06	1,433
1987	278,687.72	235,547	260,048	18,640	7.37	2,529
1988	261,939.66	217,960	240,631	21,308	7.92	2,690
1989	343,487.90	282,484	311,867	31,621	8.26	3,828
1990	675,875.94	548,811	605,896	69,980	8.62	8,118
1991	729,363.86	584,293	645,068	84,295	9.00	9,366
1992	703,487.48	555,474	613,252	90,236	9.39	9,610
1993	590,246.90	458,917	506,651	83,595	9.80	8,530
1994	821,941.31	628,621	694,007	127,934	10.23	12,506

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1995	1,024,362.45	769,706	849,767	174,595	10.67	16,363
1996	730,488.10	538,735	594,772	135,716	11.12	12,205
1997	942,706.65	681,577	752,471	190,235	11.59	16,414
1998	865,447.14	612,563	676,279	189,168	12.07	15,673
1999	1,127,337.61	780,230	861,386	265,952	12.57	21,158
2000	1,185,205.38	800,962	884,274	300,931	13.07	23,025
2001	1,561,196.12	1,028,672	1,135,670	425,526	13.59	31,312
2002	1,313,318.61	842,363	929,982	383,337	14.12	27,149
2003	1,055,268.73	660,176	728,844	326,424	14.51	22,496
2004	996,358.53	604,590	667,477	328,882	15.07	21,824
2005	1,118,446.70	656,976	725,312	393,135	15.63	25,153
2006	6,189,279.50	3,511,797	3,877,078	2,312,202	16.20	142,729
2007	708,649.61	388,907	429,359	279,290	16.65	16,774
2008	2,577,114.63	1,372,056	1,514,771	1,062,344	17.13	62,017
2009	1,060,758.96	541,624	597,961	462,798	17.73	26,103
2010	800,021.21	392,010	432,785	367,236	18.21	20,167
2011	1,562,965.95	729,905	805,826	757,140	18.83	40,209
2012	1,289,912.71	573,753	633,432	656,481	19.34	33,944
2013	2,089,785.48	881,889	973,619	1,116,166	19.86	56,202
2014	2,689,605.10	1,067,504	1,178,541	1,511,064	20.51	73,675
2015	1,803,573.87	671,831	741,712	1,061,862	21.06	50,421
2016	2,634,964.95	915,123	1,010,310	1,624,655	21.61	75,181
2017	2,972,743.00	955,142	1,054,491	1,918,252	22.18	86,486
2018	6,456,849.51	1,907,353	2,105,747	4,351,102	22.66	192,017
2019	2,164,411.72	581,361	641,831	1,522,580	23.15	65,770
2020	2,327,211.35	560,392	618,681	1,708,530	23.65	72,242
2021	2,620,447.81	555,273	613,030	2,007,418	24.17	83,054
2022	5,327,121.27	972,732	1,073,911	4,253,210	24.62	172,754
2023	3,742,688.30	571,134	630,541	3,112,148	25.00	124,486
2024	4,622,003.63	561,111	619,475	4,002,528	25.32	158,078
2025	6,579,724.90	588,885	650,138	5,929,587	25.43	233,173
2026	4,377,671.07	245,150	270,649	4,107,022	25.31	162,269
2027	5,337,593.31	108,887	120,213	5,217,380	23.95	217,845
	88,075,780.56	31,720,494	35,010,158	53,065,623		2,469,675

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1955	397.46	397	397			
1956	2,676.97	2,677	2,677			
1957	1,002.03	1,002	1,002			
1958	4,695.34	4,695	4,695			
1959	2,287.80	2,288	2,288			
1960	7,081.74	7,082	7,082			
1961	22,448.05	22,330	22,448			
1962	39,751.52	39,288	39,752			
1963	46,962.98	46,089	46,963			
1964	104,679.08	101,975	104,679			
1965	195,114.67	188,611	195,115			
1966	290,766.53	278,895	290,767			
1967	230,852.69	219,631	230,853			
1968	273,770.89	258,333	273,771			
1969	414,791.09	388,174	414,791			
1970	358,184.67	332,317	358,185			
1971	234,207.36	215,405	234,207			
1972	233,563.40	212,933	233,563			
1973	104,171.91	94,131	104,172			
1974	32,529.94	29,133	32,530			
1975	53,924.35	47,858	53,479	446	4.05	110
1976	23,476.75	20,640	23,064	413	4.35	95
1977	39,164.64	34,117	38,124	1,041	4.64	224
1978	34,707.91	29,936	33,452	1,256	4.95	254
1979	107,402.55	91,740	102,514	4,888	5.25	931
1980	818,368.10	691,750	772,993	45,375	5.57	8,146
1981	1,178,000.17	985,268	1,100,983	77,017	5.89	13,076
1982	76,439.89	67,795	75,757	683	5.77	118
1983	45,264.46	39,661	44,319	945	6.25	151
1984	228,289.15	198,452	221,759	6,530	6.50	1,005
1985	452,553.58	390,056	435,866	16,687	6.77	2,465
1986	554,903.87	473,832	529,481	25,422	7.06	3,601
1987	497,330.06	420,343	469,710	27,620	7.37	3,748
1988	609,338.28	507,030	566,578	42,760	7.92	5,399
1989	573,768.95	471,868	527,287	46,482	8.26	5,627
1990	575,115.53	466,994	521,840	53,275	8.62	6,180
1991	681,658.35	546,077	610,211	71,447	9.00	7,939
1992	1,040,069.28	821,239	917,690	122,379	9.39	13,033
1993	1,236,576.93	961,439	1,074,356	162,221	9.80	16,553
1994	2,226,229.26	1,702,620	1,902,585	323,644	10.23	31,637
1995	363,720.71	273,300	305,398	58,323	10.67	5,466

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1996	1,120,076.14	826,056	923,073	197,004	11.12	17,716
1997	1,051,542.64	760,265	849,555	201,988	11.59	17,428
1998	1,456,806.49	1,031,128	1,152,229	304,577	12.07	25,234
1999	727,863.40	503,754	562,918	164,946	12.57	13,122
2000	780,937.42	527,758	589,741	191,197	13.07	14,629
2001	919,738.01	606,015	677,189	242,549	13.59	17,848
2002	939,115.01	602,348	673,091	266,024	14.12	18,840
2003	575,941.30	360,309	402,626	173,316	14.51	11,945
2004	1,756,424.73	1,065,799	1,190,972	565,452	15.07	37,522
2005	1,206,927.56	708,949	792,212	414,716	15.63	26,533
2006	1,258,073.59	713,831	797,667	460,406	16.20	28,420
2007	944,596.09	518,394	579,277	365,319	16.65	21,941
2008	511,131.55	272,126	304,086	207,046	17.13	12,087
2009	729,010.80	372,233	415,950	313,061	17.73	17,657
2010	383,721.45	188,024	210,107	173,615	18.21	9,534
2011	1,174,710.94	548,590	613,019	561,692	18.83	29,830
2012	515,198.60	229,160	256,074	259,125	19.34	13,398
2013	652,273.74	275,260	307,588	344,686	19.86	17,356
2014	998,719.81	396,392	442,946	555,773	20.51	27,098
2015	1,056,856.49	393,679	439,915	616,942	21.06	29,294
2016	939,208.48	326,187	364,496	574,712	21.61	26,595
2017	910,264.92	292,468	326,817	583,448	22.18	26,305
2018	3,334,468.31	985,002	1,100,686	2,233,782	22.66	98,578
2019	670,814.77	180,181	201,342	469,472	23.15	20,280
2020	1,794,981.88	432,232	482,996	1,311,986	23.65	55,475
2021	1,183,408.43	250,764	280,215	903,193	24.17	37,368
2022	3,538,028.52	646,044	721,919	2,816,110	24.62	114,383
2023	2,696,198.72	411,440	459,762	2,236,437	25.00	89,457
2024	2,545,183.82	308,985	345,274	2,199,910	25.32	86,884
2025	5,183,440.72	463,918	518,403	4,665,038	25.43	183,446
2026	5,954,302.89	333,441	372,602	5,581,701	25.31	220,533
2027	5,120,907.89	104,467	116,736	5,004,172	23.95	208,942
	66,647,114.00	27,322,600	30,398,867	36,248,247		1,701,436
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1966	15,803.59	15,158	14,170	1,633	1.47	1,111
1967	22,716.10	21,612	20,204	2,512	1.75	1,435

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1968	39,690.63	37,452	35,011	4,679	2.03	2,305
1969	26,808.80	25,088	23,453	3,356	2.31	1,453
1970	25,345.13	23,515	21,983	3,363	2.60	1,293
1971	63,054.78	57,993	54,214	8,841	2.89	3,059
1972	87,273.15	79,564	74,379	12,894	3.18	4,055
1973	47,162.78	42,617	39,840	7,323	3.47	2,110
1974	50,160.90	44,922	41,995	8,166	3.76	2,172
1975	32,574.52	28,910	27,026	5,548	4.05	1,370
1976	13,274.92	11,671	10,910	2,364	4.35	543
1977	7,821.57	6,813	6,369	1,453	4.64	313
1978	19,748.31	17,033	15,923	3,825	4.95	773
1979	80,343.23	68,627	64,155	16,188	5.25	3,083
1980	34,494.69	29,158	27,258	7,237	5.57	1,299
1981	73,121.29	61,158	57,173	15,949	5.89	2,708
1982	64,022.97	56,782	53,082	10,941	5.77	1,896
1983	50,168.07	43,957	41,092	9,076	6.25	1,452
1984	65,936.67	57,319	53,584	12,353	6.50	1,900
1985	86,983.85	74,971	70,085	16,898	6.77	2,496
1986	60,923.48	52,023	48,633	12,291	7.06	1,741
1987	10,716.46	9,058	8,468	2,249	7.37	305
1988	23,772.11	19,781	18,492	5,280	7.92	667
1989	150,777.17	123,999	115,918	34,859	8.26	4,220
1990	176,174.61	143,054	133,732	42,443	8.62	4,924
1991	151,495.50	121,363	113,454	38,041	9.00	4,227
1992	72,771.96	57,461	53,716	19,056	9.39	2,029
1993	62,695.01	48,745	45,568	17,127	9.80	1,748
1995	23,634.64	17,759	16,602	7,033	10.67	659
1996	16,065.26	11,848	11,076	4,989	11.12	449
2000	4,125.32	2,788	2,606	1,519	13.07	116
2001	3,624.02	2,388	2,232	1,392	13.59	102
2002	14,375.02	9,220	8,619	5,756	14.12	408
2003	100,635.53	62,958	58,855	41,780	14.51	2,879
2004	44,634.86	27,084	25,319	19,316	15.07	1,282
2006	128,208.21	72,745	68,004	60,204	16.20	3,716
2008	82,121.04	43,721	40,872	41,249	17.13	2,408
2011	31,262.34	14,600	13,649	17,614	18.83	935
2012	738,472.58	328,473	307,067	431,405	19.34	22,306
2013	1,249,900.73	527,458	493,085	756,816	19.86	38,108
2014	610,461.48	242,292	226,503	383,959	20.51	18,721
2015	878,794.50	327,351	306,018	572,776	21.06	27,197
2016	423,732.14	147,162	137,572	286,160	21.61	13,242

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
2017	800,692.19	257,262	240,497	560,195	22.18	25,257
2018	970,520.48	286,692	268,009	702,511	22.66	31,002
2019	873,730.55	234,684	219,390	654,340	23.15	28,265
2020	833,592.72	200,729	187,648	645,945	23.65	27,313
2021	959,431.15	203,303	190,054	769,377	24.17	31,832
2022	1,203,906.10	219,833	205,507	998,399	24.62	40,552
2023	1,446,712.04	220,768	206,381	1,240,331	25.00	49,613
2024	899,066.04	109,147	102,034	797,032	25.32	31,478
2025	778,449.44	69,671	65,131	713,319	25.43	28,050
2027	429,885.37	8,770	8,198	421,687	23.95	17,607
	15,161,866.00	5,028,510	4,700,817	10,461,049		500,184
	169,884,760.56	64,071,604	70,109,842	99,774,919		4,671,295
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.4	2.75

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	2,241,904.50	1,922,433	1,473,880	768,025	2.91	263,926
2012	2,367,660.70	1,919,226	1,471,421	896,240	3.62	247,580
2013	1,207,072.28	945,138	724,613	482,459	4.02	120,015
2014	80,848.53	60,685	46,526	34,323	4.49	7,644
2015	1,061,788.42	757,905	581,066	480,722	5.01	95,952
2016	679,285.12	457,023	350,388	328,897	5.59	58,837
2017	1,081,773.85	679,246	520,760	561,013	6.22	90,195
2018	1,114,264.90	643,599	493,431	620,834	6.95	89,329
2019	2,489,649.81	1,305,572	1,000,948	1,488,701	7.71	193,087
2020	2,694,845.10	1,259,032	965,267	1,729,578	8.55	202,290
2021	2,388,814.75	973,681	746,496	1,642,319	9.45	173,790
2022	1,549,401.71	536,093	411,009	1,138,393	10.40	109,461
2023	1,782,524.99	505,346	387,436	1,395,089	11.37	122,699
2024	1,288,286.06	284,454	218,084	1,070,203	12.35	86,656
2025	387,545.86	61,155	46,886	340,660	13.35	25,518
2026	2,196,078.03	207,749	159,276	2,036,802	14.35	141,937
2027	2,671,158.41	84,409	64,714	2,606,444	15.35	169,801
	27,282,903.02	12,602,746	9,662,200	17,620,703		2,198,717
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	25,295.48	24,797	25,295			
2000	70,843.05	68,916	70,843			
2001	414,400.60	400,311	414,401			
2002	1,288,449.61	1,236,267	1,283,202	5,248	1.07	4,905
2003	553,282.06	525,950	545,918	7,364	1.26	5,844
2004	2,214,644.22	2,080,215	2,159,191	55,454	1.50	36,969
2005	948,152.67	881,782	915,259	32,894	1.67	19,697
2006	1,026,929.15	942,721	978,512	48,418	1.90	25,483
2007	1,216,987.50	1,101,617	1,143,440	73,547	2.12	34,692
2008	402,349.38	359,338	372,980	29,369	2.33	12,605
2009	44,879.93	39,355	40,849	4,031	2.60	1,550
2010	214,896.27	184,274	191,270	23,626	2.91	8,119
2011	172,568.51	144,077	149,547	23,022	3.26	7,062
2012	94,558.06	76,649	79,559	14,999	3.62	4,143
2013	67,624.34	52,950	54,960	12,664	4.02	3,150
2014	165,252.62	124,039	128,748	36,504	4.49	8,130
2016	192,584.63	129,571	134,490	58,094	5.59	10,392

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2017	977,870.36	614,005	637,316	340,555	6.22	54,752
2018	334,583.82	193,256	200,593	133,991	6.95	19,279
2019	40,575.76	21,278	22,086	18,490	7.71	2,398
2020	312,355.22	145,932	151,472	160,883	8.55	18,817
2021	547,294.95	223,077	231,546	315,749	9.45	33,413
2022	892,764.38	308,896	320,623	572,141	10.40	55,014
2023	1,677,929.08	475,693	493,753	1,184,176	11.37	104,149
2024	1,555,325.47	343,416	356,454	1,198,872	12.35	97,075
2025	598,190.74	94,394	97,978	500,213	13.35	37,469
2026	2,986,153.55	282,490	293,215	2,692,939	14.35	187,661
2027	2,562,473.09	80,974	84,048	2,478,425	15.35	161,461
	21,599,214.50	11,156,240	11,577,547	10,021,667		954,229
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1986	6,845.85	6,846	6,846			
1988	2,865.11	2,865	2,865			
1989	1,391.92	1,392	1,392			
1991	2,630.18	2,630	2,630			
1992	212.29	212	212			
1993	424.58	425	425			
2009	396,383.10	347,588	364,300	32,083	2.60	12,340
2020	5,164.22	2,413	2,529	2,635	8.55	308
2021	5,127.99	2,090	2,190	2,938	9.45	311
2027	215,080.92	6,797	7,124	207,957	15.35	13,548
	636,126.16	373,258	390,513	245,613		26,507
	49,518,243.68	24,132,244	21,630,260	27,887,983		3,179,453

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.8 6.42

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	87,487.96	72,149	78,284	9,204	7.89	1,167
1972	81,673.87	66,719	72,392	9,282	8.24	1,126
1973	111,961.11	90,589	98,292	13,670	8.59	1,591
1974	119,821.66	95,964	104,124	15,698	8.96	1,752
1975	83,013.36	65,783	71,376	11,637	9.34	1,246
1976	43,485.09	34,083	36,981	6,504	9.73	668
1977	75,584.94	58,570	63,550	12,035	10.13	1,188
1978	88,856.66	68,025	73,809	15,048	10.55	1,426
1979	280,532.09	212,144	230,182	50,350	10.97	4,590
1980	532,529.93	397,502	431,301	101,229	11.41	8,872
1981	604,025.37	444,828	482,651	121,375	11.86	10,234
1982	487,208.88	390,206	423,384	63,825	11.25	5,673
1983	508,144.35	402,501	436,725	71,420	11.61	6,152
1984	446,524.34	349,539	379,259	67,265	12.00	5,605
1985	629,188.59	486,489	527,854	101,335	12.39	8,179
1986	646,018.43	492,977	534,894	111,125	12.81	8,675
1987	725,413.72	546,019	592,446	132,968	13.22	10,058
1988	937,431.57	691,731	750,547	186,884	13.94	13,406
1989	1,020,669.67	741,823	804,898	215,771	14.38	15,005
1990	1,276,637.28	913,051	990,685	285,952	14.83	19,282
1991	1,273,944.83	895,838	972,009	301,936	15.30	19,734
1992	1,197,204.83	827,149	897,479	299,726	15.77	19,006
1993	932,144.55	632,180	685,933	246,212	16.25	15,152
1994	1,325,370.96	881,372	956,313	369,058	16.75	22,033
1995	1,467,960.31	956,229	1,037,535	430,426	17.26	24,938
1996	1,368,828.88	872,628	946,825	422,004	17.77	23,748
1997	1,614,511.99	1,006,164	1,091,715	522,796	18.29	28,584
1998	1,787,472.74	1,087,498	1,179,965	607,508	18.83	32,263
1999	1,757,132.29	1,042,331	1,130,958	626,175	19.37	32,327
2000	1,792,412.79	1,035,477	1,123,521	668,892	19.92	33,579
2001	1,741,485.25	978,366	1,061,554	679,931	20.48	33,200
2002	1,008,191.93	552,388	599,356	408,836	20.83	19,627
2003	1,403,356.81	745,323	808,696	594,661	21.41	27,775
2004	1,103,094.59	566,770	614,961	488,134	22.00	22,188
2005	1,275,776.52	633,040	686,866	588,911	22.59	26,070
2006	1,340,054.64	640,680	695,155	644,899	23.20	27,797
2007	7,083,281.86	3,270,351	3,548,420	3,534,861	23.61	149,719
2008	2,982,186.90	1,331,845	1,445,088	1,537,099	24.17	63,595
2009	2,188,284.02	939,212	1,019,071	1,169,213	24.60	47,529
2011	1,779,671.60	693,004	751,928	1,027,743	25.87	39,727
2012	2,196,987.21	813,764	882,956	1,314,031	26.34	49,887

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	2,709,272.31	946,620	1,027,109	1,682,164	27.00	62,302
2014	2,011,614.92	662,626	718,967	1,292,648	27.48	47,040
2015	2,683,880.56	828,782	899,251	1,784,629	27.98	63,782
2016	2,865,962.68	823,964	894,024	1,971,939	28.50	69,191
2017	2,889,742.31	767,516	832,776	2,056,966	29.03	70,857
2018	3,918,280.24	952,926	1,033,951	2,884,329	29.56	97,575
2019	2,969,111.80	656,174	711,967	2,257,145	29.96	75,339
2020	1,902,015.84	375,078	406,970	1,495,046	30.52	48,986
2021	4,700,770.98	816,054	885,441	3,815,330	30.95	123,274
2022	5,628,952.98	842,091	913,692	4,715,261	31.26	150,840
2023	9,054,469.33	1,128,187	1,224,114	7,830,356	31.60	247,796
2024	5,559,926.69	550,433	597,235	4,962,692	31.84	155,863
2025	4,044,877.06	295,276	320,383	3,724,495	31.75	117,307
2026	5,842,362.67	266,412	289,064	5,553,298	31.39	176,913
2027	6,879,142.39	114,194	123,904	6,755,239	29.62	228,063
	111,065,947.13	37,048,634	40,198,782	70,867,165		2,619,501
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1977	203.20	157	183	20	10.13	2
1978	411.20	315	367	44	10.55	4
1979	958.15	725	845	114	10.97	10
1980	1,782.81	1,331	1,550	232	11.41	20
1981	1,056.40	778	906	150	11.86	13
1982	13,798.46	11,051	12,873	925	11.25	82
1983	212.09	168	196	16	11.61	1
1984	8,513.78	6,665	7,764	750	12.00	62
1985	147.05	114	133	14	12.39	1
1986	1,429.93	1,091	1,271	159	12.81	12
1987	1,752.16	1,319	1,536	216	13.22	16
2000	4,313.02	2,492	2,903	1,410	19.92	71
2001	1,685.98	947	1,103	583	20.48	28
2006	1,114.00	533	621	493	23.20	21
2007	1,136,336.86	524,647	611,149	525,188	23.61	22,244
2008	939,364.72	419,520	488,689	450,676	24.17	18,646
2009	650,372.98	279,140	325,164	325,209	24.60	13,220
2010	631,510.63	258,604	301,242	330,269	25.24	13,085
2011	777,699.22	302,836	352,767	424,933	25.87	16,426

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2012	846,480.92	313,537	365,232	481,249	26.34	18,271
2013	631,712.75	220,720	257,112	374,601	27.00	13,874
2014	470,931.14	155,125	180,701	290,230	27.48	10,561
2015	391,695.93	120,956	140,899	250,797	27.98	8,963
2016	523,048.03	150,376	175,169	347,879	28.50	12,206
2017	1,022,735.99	271,639	316,426	706,310	29.03	24,330
2018	663,270.02	161,307	187,903	475,367	29.56	16,081
2019	1,194,682.00	264,025	307,557	887,125	29.96	29,610
2020	703,472.09	138,725	161,598	541,875	30.52	17,755
2021	910,882.36	158,129	184,201	726,682	30.95	23,479
2022	2,566,572.37	383,959	447,265	2,119,308	31.26	67,796
2023	4,016,474.39	500,453	582,966	3,433,508	31.60	108,655
2024	2,208,127.70	218,605	254,648	1,953,480	31.84	61,353
2025	654,919.93	47,809	55,692	599,228	31.75	18,873
	20,977,668.26	4,917,798	5,728,628	15,249,040		515,771
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	19,905.63	16,416	14,307	5,598	7.89	710
1972	10,173.46	8,311	7,243	2,930	8.24	356
1973	78,102.19	63,193	55,075	23,027	8.59	2,681
1974	19,283.51	15,444	13,460	5,823	8.96	650
1975	7,482.00	5,929	5,167	2,315	9.34	248
1976	1,403.92	1,100	959	445	9.73	46
1977	8.23	6	5	3	10.13	
1978	932.14	714	622	310	10.55	29
1979	10,140.76	7,669	6,684	3,457	10.97	315
1980	35,109.11	26,207	22,841	12,269	11.41	1,075
1981	32,359.38	23,831	20,770	11,590	11.86	977
1982	29,754.43	23,830	20,769	8,986	11.25	799
1983	30,639.79	24,270	21,152	9,487	11.61	817
1984	52,733.37	41,280	35,977	16,756	12.00	1,396
1985	57,785.65	44,680	38,941	18,845	12.39	1,521
1986	73,313.98	55,946	48,759	24,555	12.81	1,917
1987	56,166.09	42,276	36,845	19,321	13.22	1,461
1988	78,283.11	57,765	50,345	27,938	13.94	2,004
1989	82,384.04	59,877	52,185	30,199	14.38	2,100
1990	84,937.61	60,747	52,944	31,994	14.83	2,157

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1991	69,196.26	48,659	42,408	26,788	15.30	1,751
1992	75,559.65	52,204	45,498	30,062	15.77	1,906
1993	101,627.82	68,924	60,070	41,558	16.25	2,557
1994	110,003.97	73,153	63,756	46,248	16.75	2,761
1995	204,528.95	133,230	116,116	88,413	17.26	5,122
1996	301,181.75	192,003	167,339	133,843	17.77	7,532
1997	535,582.62	333,775	290,900	244,683	18.29	13,378
1998	380,692.62	231,613	201,861	178,832	18.83	9,497
1999	383,800.52	227,670	198,424	185,376	19.37	9,570
2000	323,155.85	186,687	162,706	160,450	19.92	8,055
2001	278,492.84	156,457	136,359	142,134	20.48	6,940
2002	341,577.91	187,151	163,110	178,468	20.83	8,568
2003	397,187.40	210,946	183,849	213,339	21.41	9,964
2004	368,203.36	189,183	164,881	203,322	22.00	9,242
2005	409,884.83	203,385	177,259	232,626	22.59	10,298
2006	673,344.79	321,926	280,573	392,772	23.20	16,930
2007	475,976.49	219,758	191,529	284,448	23.61	12,048
2008	836,433.89	373,551	325,566	510,868	24.17	21,136
2009	328,191.43	140,860	122,766	205,426	24.60	8,351
2010	396,898.32	162,530	141,652	255,246	25.24	10,113
2011	788,625.70	307,091	267,643	520,982	25.87	20,138
2012	629,240.41	233,071	203,132	426,109	26.34	16,177
2013	752,140.80	262,798	229,040	523,101	27.00	19,374
2014	1,058,980.84	348,828	304,019	754,962	27.48	27,473
2015	2,014,513.70	622,082	542,172	1,472,342	27.98	52,621
2016	652,342.50	187,548	163,456	488,886	28.50	17,154
2017	708,240.58	188,109	163,945	544,295	29.03	18,749
2018	1,264,078.90	307,424	267,933	996,145	29.56	33,699
2019	555,706.44	122,811	107,035	448,671	29.96	14,976
2020	18,776.96	3,703	3,227	15,550	30.52	510
2021	1,150,010.90	199,642	173,997	976,014	30.95	31,535
2022	758,640.32	113,493	98,914	659,726	31.26	21,104
2023	667,160.54	83,128	72,450	594,711	31.60	18,820
2024	1,069,658.92	105,896	92,293	977,366	31.84	30,696

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2025	874,992.29	63,874	55,669	819,323	31.75	25,805
2026	435,967.05	19,880	17,326	418,641	31.39	13,337
2027	436,561.66	7,247	6,316	430,246	29.62	14,526
	21,588,058.18	7,469,781	6,510,241	15,077,817		573,672
	153,631,673.57	49,436,213	52,437,652	101,194,022		3,708,944
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.3	2.41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1944	77.95	78	78			
1957	117.06	108	91	26	3.63	7
1962	2,151.47	1,908	1,605	546	5.09	107
1964	17,920.86	15,663	13,178	4,743	5.67	837
1965	20,920.63	18,145	15,266	5,654	5.97	947
1966	29,758.73	25,606	21,544	8,215	6.28	1,308
1967	33,875.31	28,915	24,328	9,548	6.59	1,449
1968	27,894.47	23,617	19,870	8,024	6.90	1,163
1969	29,312.36	24,609	20,705	8,607	7.22	1,192
1970	46,449.79	38,656	32,523	13,926	7.55	1,845
1971	42,432.58	34,993	29,441	12,991	7.89	1,647
1972	30,600.18	24,997	21,031	9,569	8.24	1,161
1973	21,528.93	17,419	14,656	6,873	8.59	800
1974	24,295.63	19,458	16,371	7,925	8.96	884
1975	33,447.98	26,506	22,301	11,147	9.34	1,193
1976	7,088.04	5,555	4,674	2,414	9.73	248
1977	17,783.83	13,781	11,595	6,189	10.13	611
1978	23,253.21	17,802	14,978	8,275	10.55	784
1979	84,123.28	63,616	53,524	30,600	10.97	2,789
1980	175,119.76	130,716	109,978	65,141	11.41	5,709
1981	85,224.43	62,763	52,806	32,419	11.86	2,733
1982	129,428.81	103,660	87,215	42,214	11.25	3,752
1983	63,138.87	50,012	42,078	21,061	11.61	1,814
1984	58,876.10	46,088	38,776	20,100	12.00	1,675
1985	123,384.92	95,401	80,266	43,119	12.39	3,480
1986	140,377.12	107,122	90,128	50,250	12.81	3,923
1987	136,832.49	102,994	86,654	50,178	13.22	3,796
1988	175,491.48	129,495	108,951	66,540	13.94	4,773
1989	213,503.89	155,175	130,557	82,947	14.38	5,768
1990	214,130.92	153,146	128,850	85,281	14.83	5,751
1991	78,271.51	55,041	46,309	31,963	15.30	2,089
1992	96,689.87	66,803	56,205	40,485	15.77	2,567
1993	33,962.96	23,034	19,380	14,583	16.25	897
1994	111,740.54	74,307	62,518	49,222	16.75	2,939
1995	158,945.89	103,537	87,111	71,835	17.26	4,162
1996	44,731.50	28,516	23,992	20,739	17.77	1,167
1997	90,392.75	56,333	47,396	42,997	18.29	2,351
1998	55,905.23	34,013	28,617	27,288	18.83	1,449
1999	104,475.10	61,975	52,143	52,332	19.37	2,702
2000	92,875.32	53,654	45,142	47,733	19.92	2,396
2001	170,338.61	95,696	80,514	89,824	20.48	4,386

UGI UTILITIES, INC. - GAS DIVISION

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2002	54,814.24	30,033	25,268	29,546	20.83	1,418
2003	133,190.26	70,737	59,515	73,675	21.41	3,441
2004	229,781.29	118,062	99,332	130,449	22.00	5,930
2005	221,319.48	109,819	92,397	128,923	22.59	5,707
2006	179,516.35	85,827	72,211	107,305	23.20	4,625
2008	542,890.68	242,455	203,990	338,900	24.17	14,022
2009	435,453.99	186,897	157,247	278,207	24.60	11,309
2010	540,142.20	221,188	186,097	354,045	25.24	14,027
2012	185,684.69	68,778	57,867	127,818	26.34	4,853
2013	64,891.21	22,673	19,076	45,815	27.00	1,697
2020	80,753.41	15,925	13,399	67,355	30.52	2,207
2022	23,952.58	3,583	3,015	20,938	31.26	670
2023	58,165.17	7,247	6,097	52,068	31.60	1,648
2024	30,384.42	3,008	2,531	27,854	31.84	875
2025	60,929.95	4,448	3,742	57,188	31.75	1,801
	5,888,740.28	3,381,593	2,845,129	3,043,611		163,481
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1950	211.54	204	212			
1952	22,872.17	21,754	22,872			
1953	3,324.65	3,141	3,325			
1954	3,638.77	3,415	3,639			
1956	2,288.98	2,119	2,289			
1957	4,312.96	3,965	4,313			
1958	523.27	478	523			
1959	5,076.98	4,602	5,077			
1960	13,576.34	12,219	13,576			
1961	9,266.15	8,280	9,266			
1962	28,692.16	25,447	28,692			
1963	14,471.10	12,741	14,471			
1964	37,803.93	33,041	37,804			
1965	38,378.73	33,287	38,379			
1966	31,246.60	26,886	31,247			
1967	24,202.13	20,658	24,202			
1968	19,889.94	16,840	19,890			
1969	19,954.10	16,753	19,954			
1970	22,762.73	18,944	22,763			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	20,289.92	16,732	20,290			
1972	17,294.88	14,128	17,295			
1973	11,492.55	9,299	11,493			
1974	24,418.58	19,557	24,419			
1975	16,319.18	12,932	16,319			
1976	25,023.29	19,613	25,023			
1977	43,118.59	33,412	43,119			
1978	25,979.99	19,889	25,980			
1979	50,315.47	38,050	50,026	289	10.97	26
1980	157,640.32	117,669	154,705	2,935	11.41	257
1981	85,258.09	62,787	82,549	2,709	11.86	228
1984	251.00	196	251			
1985	76,948.28	59,496	76,948			
1986	6,297.30	4,805	6,297			
1987	4,517.67	3,400	4,474	44	13.22	3
1988	436.80	322	424	13	13.94	1
1989	61,414.76	44,636	58,736	2,679	14.38	186
1990	113,229.49	80,982	106,564	6,666	14.83	449
1991	3,009.98	2,117	2,786	224	15.30	15
1992	70,156.42	48,471	63,783	6,374	15.77	404
1993	67,108.70	45,513	59,890	7,218	16.25	444
1994	82,593.19	54,924	72,274	10,319	16.75	616
1995	26,780.69	17,445	22,956	3,825	17.26	222
1996	1,225.32	781	1,028	198	17.77	11
1997	216,693.86	135,044	177,704	38,990	18.29	2,132
1998	256,742.97	156,202	205,545	51,198	18.83	2,719
1999	8,429.94	5,001	6,581	1,849	19.37	95
2000	84,587.64	48,866	64,302	20,285	19.92	1,018
2001	118,361.21	66,495	87,500	30,861	20.48	1,507
2002	169,552.53	92,898	122,244	47,309	20.83	2,271
2003	148,288.73	78,756	103,635	44,654	21.41	2,086
2004	220,104.20	113,090	148,814	71,290	22.00	3,240
2007	122,142.22	56,393	74,207	47,935	23.61	2,030
2009	114,064.35	48,956	64,421	49,643	24.60	2,018
2010	62,519.49	25,602	33,690	28,830	25.24	1,142
2018	45.98	11	14	32	29.56	1
2022	6,986.91	1,045	1,375	5,612	31.26	180

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2023	18,231.73	2,272	2,990	15,242	31.60	482
2024	57,581.69	5,701	7,502	50,080	31.84	1,573
2025	18,398.87	1,343	1,767	16,632	31.75	524
	2,916,346.01	1,829,605	2,352,413	563,933		25,880
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1970	5,001.66	4,162	5,002			
1971	12,065.77	9,950	12,066			
1972	16,158.21	13,199	16,158			
1973	23,610.65	19,104	23,611			
1974	11,934.41	9,558	11,934			
1975	6,620.80	5,247	6,621			
1976	3,884.68	3,045	3,844	40	9.73	4
1977	5,230.27	4,053	5,117	113	10.13	11
1978	5,706.05	4,368	5,515	191	10.55	18
1979	25,223.43	19,074	24,081	1,142	10.97	104
1980	21,935.83	16,374	20,672	1,264	11.41	111
1981	13,794.39	10,159	12,826	969	11.86	82
1982	18,523.58	14,836	18,524			
1983	29,007.23	22,977	29,007			
1984	25,172.95	19,705	24,883	290	12.00	24
1985	27,049.72	20,915	26,411	638	12.39	51
1986	27,469.49	20,962	26,471	999	12.81	78
1987	27,188.25	20,465	25,843	1,345	13.22	102
1988	33,227.77	24,519	30,963	2,265	13.94	162
1989	49,270.86	35,810	45,221	4,050	14.38	282
1990	52,753.58	37,729	47,644	5,109	14.83	345
1991	51,222.02	36,019	45,485	5,737	15.30	375
1992	54,594.81	37,720	47,633	6,962	15.77	441
1993	58,410.15	39,614	50,025	8,386	16.25	516
1994	72,041.99	47,908	60,498	11,544	16.75	689
1995	66,567.19	43,362	54,757	11,810	17.26	684
1996	69,627.81	44,388	56,053	13,575	17.77	764
1997	42,597.30	26,547	33,524	9,074	18.29	496
1998	67,630.64	41,146	51,959	15,672	18.83	832
1999	15,985.66	9,483	11,975	4,011	19.37	207
2000	19,079.45	11,022	13,919	5,161	19.92	259

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	14,019.42	7,876	9,946	4,074	20.48	199
2002	20,738.40	11,363	14,349	6,389	20.83	307
2003	16,488.67	8,757	11,058	5,430	21.41	254
2004	16,273.80	8,361	10,558	5,716	22.00	260
2005	8,074.49	4,007	5,060	3,014	22.59	133
2006	19,031.70	9,099	11,490	7,541	23.20	325
2007	18,179.90	8,394	10,600	7,580	23.61	321
2008	21,615.63	9,654	12,191	9,425	24.17	390
2009	25,708.61	11,034	13,934	11,775	24.60	479
2010	17,915.17	7,336	9,264	8,651	25.24	343
2011	25,078.47	9,766	12,332	12,746	25.87	493
2012	43,118.70	15,971	20,168	22,951	26.34	871
2013	31,965.64	11,169	14,104	17,861	27.00	662
2014	28,084.77	9,251	11,682	16,403	27.48	597
2015	17,007.06	5,252	6,632	10,375	27.98	371
2016	34,471.28	9,910	12,514	21,957	28.50	770
2017	118,289.24	31,418	39,675	78,615	29.03	2,708
2018	11,207.60	2,726	3,442	7,765	29.56	263
2019	341.14	75	95	246	29.96	8
2021	2,474.84	430	543	1,932	30.95	62
2022	3,340.12	500	631	2,709	31.26	87
2023	4,497.06	560	707	3,790	31.60	120
2024	3,946.39	391	494	3,453	31.84	108
2025	8,582.07	626	791	7,792	31.75	245
	1,469,036.77	857,346	1,080,502	388,535		17,013
	10,274,123.06	6,068,544	6,278,044	3,996,079		206,374

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.4 2.01

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	32,099.03	26,471	29,963	2,136	7.89	271
1972	38,136.64	31,153	35,263	2,873	8.24	349
1973	46,699.12	37,785	42,770	3,929	8.59	457
1974	41,287.45	33,067	37,430	3,858	8.96	431
1975	28,525.71	22,605	25,587	2,938	9.34	315
1976	20,710.12	16,232	18,374	2,337	9.73	240
1977	30,396.78	23,554	26,662	3,735	10.13	369
1978	40,769.14	31,211	35,329	5,440	10.55	516
1979	68,832.87	52,053	58,921	9,912	10.97	904
1980	131,408.86	98,089	111,030	20,378	11.41	1,786
1981	110,631.00	81,473	92,222	18,409	11.86	1,552
1982	190,335.00	152,439	172,551	17,784	11.25	1,581
1983	141,533.91	112,109	126,900	14,634	11.61	1,260
1984	96,589.58	75,610	85,586	11,004	12.00	917
1985	157,339.96	121,655	137,706	19,634	12.39	1,585
1986	142,951.52	109,086	123,478	19,473	12.81	1,520
1987	168,313.63	126,690	143,405	24,909	13.22	1,884
1988	176,855.08	130,501	147,719	29,136	13.94	2,090
1989	245,809.88	178,655	202,226	43,584	14.38	3,031
1990	200,239.89	143,212	162,107	38,133	14.83	2,571
1991	127,914.76	89,950	101,818	26,097	15.30	1,706
1992	194,224.55	134,190	151,894	42,330	15.77	2,684
1993	110,374.14	74,856	84,732	25,642	16.25	1,578
1994	159,243.25	105,897	119,869	39,375	16.75	2,351
1995	225,556.84	146,928	166,313	59,244	17.26	3,432
1996	146,163.86	93,179	105,473	40,691	17.77	2,290
1997	183,670.61	114,464	129,566	54,105	18.29	2,958
1998	242,997.43	147,840	167,345	75,652	18.83	4,018
1999	163,009.46	96,697	109,455	53,555	19.37	2,765
2000	129,708.02	74,932	84,818	44,890	19.92	2,254
2001	175,354.91	98,514	111,511	63,843	20.48	3,117
2002	178,137.48	97,602	110,479	67,658	20.83	3,248
2003	463,652.54	246,246	278,734	184,918	21.41	8,637
2004	582,927.65	299,508	339,024	243,904	22.00	11,087
2005	461,613.81	229,053	259,273	202,341	22.59	8,957
2006	271,218.43	129,670	146,778	124,440	23.20	5,364
2008	801,363.82	357,889	405,107	396,257	24.17	16,395
2009	189,343.07	81,266	91,988	97,355	24.60	3,958
2010	213,698.43	87,510	99,056	114,643	25.24	4,542
2011	310,820.65	121,034	137,003	173,818	25.87	6,719
2012	514,236.52	190,473	215,603	298,633	26.34	11,338

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	418,060.32	146,070	165,342	252,719	27.00	9,360
2014	466,917.86	153,803	174,095	292,823	27.48	10,656
2015	456,957.65	141,109	159,726	297,231	27.98	10,623
2016	686,364.70	197,330	223,365	463,000	28.50	16,246
2017	746,787.10	198,347	224,516	522,271	29.03	17,991
2018	883,633.27	214,900	243,253	640,380	29.56	21,664
2019	540,738.04	119,503	135,270	405,468	29.96	13,534
2020	181,428.19	35,778	40,498	140,930	30.52	4,618
2021	270,428.66	46,946	53,140	217,289	30.95	7,021
2022	38,388.69	5,743	6,501	31,888	31.26	1,020
2023	2,635.29	328	371	2,264	31.60	72
2024	3,310.00	328	371	2,939	31.84	92
2025	219,866.82	16,050	18,168	201,699	31.75	6,353
	12,870,211.99	5,897,583	6,675,681	6,194,531		252,277
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1972	13,313.98	10,876	13,314			
1973	38,836.17	31,423	38,836			
1974	144,406.45	115,654	144,406			
1975	99,258.76	78,657	99,259			
1976	162,178.02	127,112	160,834	1,344	9.73	138
1977	227,638.93	176,395	223,191	4,448	10.13	439
1978	126,268.54	96,666	122,311	3,958	10.55	375
1979	78,656.93	59,482	75,262	3,395	10.97	309
1980	57,030.55	42,570	53,863	3,167	11.41	278
1981	109,907.92	80,941	102,414	7,494	11.86	632
1985	24,654.43	19,063	24,120	534	12.39	43
1986	27,447.15	20,945	26,502	946	12.81	74
1988	68,000.86	50,178	63,490	4,511	13.94	324
1989	58,448.77	42,481	53,751	4,698	14.38	327
1990	51,140.66	36,576	46,279	4,861	14.83	328
1991	39,011.61	27,433	34,711	4,301	15.30	281
1992	35,854.73	24,772	31,344	4,511	15.77	286
1993	51,676.44	35,047	44,345	7,332	16.25	451
1994	71,235.62	47,372	59,939	11,296	16.75	674
1995	49,500.84	32,245	40,799	8,702	17.26	504
1996	45,909.70	29,267	37,031	8,878	17.77	500

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1997	34,534.58	21,522	27,232	7,303	18.29	399
1998	49,970.37	30,402	38,467	11,503	18.83	611
1999	46,832.83	27,781	35,151	11,682	19.37	603
2000	39,699.21	22,934	29,018	10,681	19.92	536
2001	45,124.99	25,351	32,076	13,049	20.48	637
2002	66,517.98	36,445	46,114	20,404	20.83	980
2003	78,667.19	41,780	52,864	25,803	21.41	1,205
2004	165,793.01	85,184	107,783	58,011	22.00	2,637
2005	119,365.27	59,229	74,942	44,423	22.59	1,966
2006	70,424.87	33,670	42,602	27,823	23.20	1,199
2007	97,997.49	45,245	57,248	40,749	23.61	1,726
2008	109,845.80	49,057	62,071	47,774	24.17	1,977
2009	119,208.92	51,164	64,737	54,472	24.60	2,214
2010	90,572.74	37,090	46,930	43,643	25.24	1,729
2011	78,430.71	30,541	38,643	39,787	25.87	1,538
2012	113,394.32	42,001	53,143	60,251	26.34	2,287
2013	103,879.46	36,295	45,924	57,956	27.00	2,147
2014	114,396.21	37,682	47,679	66,718	27.48	2,428
2015	12,301.93	3,799	4,807	7,495	27.98	268
2016	95,701.05	27,514	34,813	60,888	28.50	2,136
2017	88,931.16	23,620	29,886	59,045	29.03	2,034
2018	56,220.18	13,673	17,300	38,920	29.56	1,317
2019	45,274.31	10,006	12,660	32,614	29.96	1,089
2020	38,662.29	7,624	9,647	29,016	30.52	951
2024	14,048.80	1,391	1,760	12,289	31.84	386
	3,476,172.73	1,986,155	2,509,498	966,675		40,963
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	5,439.90	4,486	5,096	344	7.89	44
1972	14,933.80	12,199	13,859	1,075	8.24	130
1973	7,861.73	6,361	7,226	635	8.59	74
1974	9,613.04	7,699	8,747	867	8.96	97
1975	4,932.44	3,909	4,441	492	9.34	53
1976	4,347.30	3,407	3,871	477	9.73	49
1977	3,525.43	2,732	3,104	422	10.13	42
1978	2,829.16	2,166	2,461	368	10.55	35
1979	3,571.30	2,701	3,069	503	10.97	46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1980	10,155.76	7,581	8,612	1,543	11.41	135
1981	8,768.97	6,458	7,337	1,432	11.86	121
1982	7,863.13	6,298	7,155	708	11.25	63
1983	27,433.37	21,730	24,687	2,747	11.61	237
1984	14,612.72	11,439	12,995	1,617	12.00	135
1985	17,814.51	13,774	15,648	2,166	12.39	175
1986	8,715.77	6,651	7,556	1,160	12.81	91
1987	6,897.76	5,192	5,898	999	13.22	76
1988	18,499.00	13,650	15,507	2,992	13.94	215
1989	17,820.76	12,952	14,714	3,107	14.38	216
1990	13,760.77	9,842	11,181	2,580	14.83	174
1991	16,073.60	11,303	12,841	3,233	15.30	211
1992	6,559.93	4,532	5,149	1,411	15.77	89
1993	29,217.11	19,815	22,511	6,706	16.25	413
1994	25,165.33	16,735	19,012	6,153	16.75	367
1995	58,774.81	38,286	43,495	15,280	17.26	885
1996	115,510.48	73,638	83,657	31,853	17.77	1,793
1997	68,827.66	42,893	48,729	20,099	18.29	1,099
1998	53,919.97	32,805	37,268	16,651	18.83	884
1999	48,940.91	29,032	32,982	15,959	19.37	824
2000	55,190.97	31,884	36,222	18,969	19.92	952
2001	36,718.99	20,629	23,436	13,283	20.48	649
2002	75,211.94	41,209	46,816	28,396	20.83	1,363
2003	104,709.50	55,611	63,177	41,532	21.41	1,940
2004	98,717.26	50,721	57,622	41,095	22.00	1,868
2005	53,701.30	26,647	30,273	23,429	22.59	1,037
2006	64,103.29	30,648	34,818	29,285	23.20	1,262
2007	57,266.33	26,440	30,037	27,229	23.61	1,153
2008	105,754.48	47,230	53,656	52,098	24.17	2,155
2009	77,881.91	33,427	37,975	39,907	24.60	1,622
2010	36,000.84	14,742	16,748	19,253	25.24	763
2011	9,612.23	3,743	4,252	5,360	25.87	207
2012	1,472.30	545	619	853	26.34	32
2013	2,742.40	958	1,088	1,654	27.00	61
2014	4,238.77	1,396	1,586	2,653	27.48	97
2015	13,257.55	4,094	4,651	8,607	27.98	308
2016	6,407.77	1,842	2,093	4,315	28.50	151
2017	3,451.34	917	1,042	2,410	29.03	83
2018	17,977.88	4,372	4,967	13,011	29.56	440

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2019	421.75	93	106	316	29.96	11
2020	197.26	39	44	153	30.52	5
2024	25,549.95	2,529	2,873	22,677	31.84	712
	1,482,972.43	829,982	942,910	540,062		25,644
	17,829,357.15	8,713,720	10,128,089	7,701,268		318,884
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					24.2	1.79

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	653	692			
1956	2,239.85	2,074	2,240			
1957	4,785.87	4,400	4,786			
1960	16,750.58	15,076	16,751			
1961	12,800.59	11,438	12,801			
1962	22,033.72	19,541	22,034			
1963	24,186.10	21,294	24,186			
1964	21,937.83	19,174	21,938			
1965	14,345.92	12,443	14,346			
1966	22,819.15	19,635	22,644	175	6.28	28
1967	33,625.63	28,701	33,100	526	6.59	80
1968	78,227.64	66,233	76,384	1,844	6.90	267
1969	79,698.42	66,912	77,167	2,532	7.22	351
1970	56,628.40	47,127	54,350	2,279	7.55	302
1971	50,484.00	41,633	48,014	2,470	7.89	313
1972	74,487.40	60,848	70,173	4,314	8.24	524
1973	5,856.45	4,739	5,465	391	8.59	46
1974	2,435.60	1,951	2,250	186	8.96	21
1975	3,447.78	2,732	3,151	297	9.34	32
1976	1,925.80	1,509	1,740	186	9.73	19
1979	129,595.68	98,003	113,023	16,573	10.97	1,511
1980	273,942.52	204,482	235,820	38,122	11.41	3,341
1981	280,781.60	206,779	238,469	42,312	11.86	3,568
1982	232,089.47	185,880	214,367	17,722	11.25	1,575
1983	89,210.82	70,664	81,494	7,717	11.61	665
1984	47,248.78	36,986	42,654	4,594	12.00	383
1985	101,055.89	78,136	90,111	10,945	12.39	883
1986	78,585.49	59,969	69,160	9,426	12.81	736
1987	157,570.97	118,604	136,781	20,790	13.22	1,573
1988	283,620.35	209,283	241,357	42,263	13.94	3,032
1989	183,420.00	133,310	153,741	29,679	14.38	2,064
1990	203,975.86	145,884	168,242	35,734	14.83	2,410
1991	221,578.38	155,814	179,694	41,885	15.30	2,738
1992	121,714.83	84,093	96,981	24,734	15.77	1,568
1993	67,829.07	46,002	53,052	14,777	16.25	909
1994	215,739.93	143,467	165,454	50,286	16.75	3,002
1995	283,678.95	184,788	213,108	70,571	17.26	4,089
1996	638,322.65	406,931	469,296	169,027	17.77	9,512
1997	114,991.22	71,663	82,646	32,345	18.29	1,768
1998	89,135.98	54,230	62,541	26,595	18.83	1,412
1999	211,901.85	125,700	144,964	66,937	19.37	3,456

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2000	61,111.51	35,304	40,715	20,397	19.92	1,024
2001	5,688.76	3,196	3,686	2,003	20.48	98
2002	124,248.21	68,076	78,509	45,739	20.83	2,196
2005	16,976.59	8,424	9,715	7,262	22.59	321
2007	36,240.36	16,732	19,296	16,944	23.61	718
2008	123,273.33	55,054	63,491	59,782	24.17	2,473
2012	13,100.09	4,852	5,596	7,504	26.34	285
2014	217,660.91	71,698	82,686	134,975	27.48	4,912
2015	137,276.88	42,391	48,888	88,389	27.98	3,159
2016	122,361.10	35,179	40,570	81,791	28.50	2,870
2017	542,789.02	144,165	166,259	376,530	29.03	12,970
2018	224,701.21	54,647	63,022	161,679	29.56	5,470
2019	656,174.48	145,015	167,240	488,935	29.96	16,320
2020	2,116,662.54	417,406	481,376	1,635,286	30.52	53,581
2021	1,046,978.33	181,755	209,610	837,368	30.95	27,056
2023	75,522.95	9,410	10,852	64,671	31.60	2,047
2024	130,066.51	12,877	14,850	115,216	31.84	3,619
2025	120,110.28	8,768	10,112	109,999	31.75	3,465
	10,326,341.61	4,583,730	5,283,639	5,042,703		194,762
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	807	860			
1956	7,054.30	6,531	7,054			
1957	11,192.51	10,290	11,193			
1958	5,050.93	4,611	5,051			
1959	689.61	625	690			
1960	32,725.24	29,453	32,725			
1961	10,605.59	9,477	10,606			
1962	22,867.17	20,281	22,867			
1963	60,787.04	53,519	60,787			
1964	79,108.77	69,141	79,109			
1965	131,939.84	114,435	131,940			
1966	124,040.09	106,729	124,040			
1967	208,085.37	177,613	208,085			
1968	233,579.88	197,765	233,580			
1969	194,219.76	163,059	193,262	958	7.22	133
1970	271,294.84	225,777	267,597	3,698	7.55	490

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	229,764.59	189,480	224,577	5,188	7.89	658
1972	257,964.38	210,729	249,762	8,203	8.24	996
1973	108,983.37	88,180	104,513	4,470	8.59	520
1974	90,753.81	72,684	86,147	4,607	8.96	514
1975	52,275.40	41,425	49,098	3,177	9.34	340
1976	53,093.99	41,614	49,322	3,772	9.73	388
1977	29,803.40	23,094	27,372	2,432	10.13	240
1978	50,738.04	38,843	46,038	4,700	10.55	445
1979	92,133.69	69,673	82,578	9,555	10.97	871
1980	489,117.73	365,097	432,723	56,395	11.41	4,943
1981	230,826.16	169,990	201,477	29,349	11.86	2,475
1982	80,975.76	64,853	76,866	4,110	11.25	365
1983	42,099.09	33,347	39,524	2,575	11.61	222
1984	46,511.61	36,409	43,153	3,359	12.00	280
1985	72,222.02	55,842	66,185	6,037	12.39	487
1986	43,855.97	33,466	39,665	4,191	12.81	327
1987	107,897.65	81,215	96,258	11,639	13.22	880
1988	160,625.82	118,526	140,480	20,146	13.94	1,445
1989	30,425.01	22,113	26,209	4,216	14.38	293
1990	108,749.56	77,778	92,185	16,565	14.83	1,117
1991	127,229.75	89,468	106,040	21,190	15.30	1,385
1992	44,347.42	30,640	36,315	8,032	15.77	509
1993	29,918.28	20,291	24,049	5,869	16.25	361
1994	29,674.28	19,733	23,388	6,286	16.75	375
1995	34,913.41	22,743	26,956	7,958	17.26	461
1996	43,150.00	27,508	32,603	10,547	17.77	594
1997	147,679.42	92,034	109,081	38,598	18.29	2,110
1998	59,434.64	36,160	42,858	16,577	18.83	880
1999	115,364.91	68,434	81,110	34,255	19.37	1,768
2000	88,357.27	51,044	60,499	27,859	19.92	1,399
2001	81,293.19	45,671	54,131	27,163	20.48	1,326
2002	24,753.36	13,562	16,074	8,679	20.83	417
2003	6,572.47	3,491	4,138	2,435	21.41	114
2004	11,469.43	5,893	6,985	4,485	22.00	204
2005	8,155.02	4,047	4,797	3,358	22.59	149
2006	8,567.60	4,096	4,855	3,713	23.20	160
2007	26,075.02	12,039	14,269	11,806	23.61	500
2008	31,803.84	14,204	16,835	14,969	24.17	619
2009	68,220.04	29,280	34,703	33,517	24.60	1,362
2010	60,218.85	24,660	29,228	30,991	25.24	1,228
2011	489,447.99	190,591	225,894	263,554	25.87	10,188

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2012	154,849.37	57,356	67,980	86,869	26.34	3,298
2013	5,908.18	2,064	2,446	3,462	27.00	128
2014	69,835.34	23,004	27,265	42,570	27.48	1,549
2015	3,012,389.09	930,226	1,102,529	1,909,860	27.98	68,258
2016	2,481,717.48	713,494	845,653	1,636,065	28.50	57,406
2017	56,121.74	14,906	17,667	38,455	29.03	1,325
2019	397,651.78	87,881	104,159	293,493	29.96	9,796
2024	862,634.10	85,401	101,220	761,415	31.84	23,914
	12,350,671.41	5,744,392	6,787,301	5,563,370		210,212
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1939	89.30	89	89			
1941	89.82	90	90			
1942	132.41	132	132			
1943	518.93	519	519			
1944	66.20	66	66			
1945	197.55	196	198			
1946	210.59	208	211			
1947	189.59	186	190			
1948	87.10	85	87			
1949	87.28	85	87			
1950	87.12	84	87			
1952	1,262.82	1,201	1,263			
1954	1,294.41	1,215	1,294			
1955	1,457.91	1,359	1,458			
1956	7,981.90	7,389	7,982			
1957	2,880.32	2,648	2,880			
1958	2,619.55	2,391	2,620			
1959	13,143.81	11,914	13,144			
1960	21,772.61	19,595	21,773			
1961	5,136.41	4,590	5,136			
1962	11,123.96	9,866	11,124			
1963	27,181.94	23,932	27,182			
1964	25,412.37	22,210	25,412			
1965	44,668.34	38,742	44,668			
1966	40,105.25	34,508	40,105			
1967	46,459.43	39,656	46,160	300	6.59	46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1968	40,660.77	34,426	40,072	589	6.90	85
1969	46,303.32	38,874	45,249	1,054	7.22	146
1970	37,700.72	31,375	36,521	1,180	7.55	156
1971	16,323.27	13,461	15,669	655	7.89	83
1972	17,258.15	14,098	16,410	848	8.24	103
1973	15,478.85	12,524	14,578	901	8.59	105
1974	23,324.67	18,680	21,744	1,581	8.96	176
1975	7,669.04	6,077	7,074	595	9.34	64
1976	8,281.22	6,491	7,556	726	9.73	75
1977	4,676.10	3,623	4,217	459	10.13	45
1978	8,780.76	6,722	7,824	956	10.55	91
1979	17,137.24	12,960	15,085	2,052	10.97	187
1980	98,738.25	73,702	85,789	12,949	11.41	1,135
1981	107,184.56	78,935	91,880	15,304	11.86	1,290
1982	81,954.72	65,638	76,403	5,552	11.25	494
1983	55,987.72	44,348	51,621	4,367	11.61	376
1984	108,836.50	85,197	99,169	9,667	12.00	806
1985	78,804.76	60,932	70,925	7,880	12.39	636
1986	100,528.92	76,714	89,295	11,234	12.81	877
1987	88,930.61	66,938	77,916	11,015	13.22	833
1988	201,347.68	148,574	172,940	28,407	13.94	2,038
1989	181,545.13	131,947	153,586	27,959	14.38	1,944
1990	168,501.06	120,512	140,276	28,225	14.83	1,903
1991	258,735.87	181,943	211,782	46,954	15.30	3,069
1992	306,750.24	211,934	246,691	60,059	15.77	3,808
1993	257,684.35	174,762	203,423	54,261	16.25	3,339
1994	299,150.67	198,935	231,561	67,590	16.75	4,035
1995	383,234.14	249,639	290,580	92,654	17.26	5,368
1996	263,349.91	167,886	195,419	67,930	17.77	3,823
1997	601,487.19	374,847	436,322	165,165	18.29	9,030
1998	655,375.22	398,730	464,122	191,253	18.83	10,157
1999	630,558.78	374,047	435,391	195,168	19.37	10,076
2000	507,499.26	293,182	341,264	166,235	19.92	8,345
2001	180,182.92	101,227	117,828	62,355	20.48	3,045
2002	499,993.98	273,947	318,875	181,119	20.83	8,695
2003	1,054,633.08	560,116	651,976	402,657	21.41	18,807
2004	899,395.97	462,110	537,897	361,499	22.00	16,432
2005	519,022.38	257,539	299,776	219,247	22.59	9,705
2006	908,049.52	434,138	505,337	402,712	23.20	17,358
2007	467,928.82	216,043	251,474	216,455	23.61	9,168
2008	725,370.17	323,950	377,078	348,292	24.17	14,410

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2009	490,205.55	210,396	244,901	245,304	24.60	9,972
2010	547,246.13	224,097	260,849	286,397	25.24	11,347
2011	966,815.36	376,478	438,221	528,595	25.87	20,433
2012	441,767.81	163,631	190,467	251,301	26.34	9,541
2013	339,500.65	118,622	138,076	201,425	27.00	7,460
2014	367,771.53	121,144	141,012	226,760	27.48	8,252
2015	392,846.52	121,311	141,206	251,640	27.98	8,994
2016	376,840.13	108,342	126,110	250,730	28.50	8,798
2017	892,410.83	237,024	275,896	616,515	29.03	21,237
2018	1,059,178.78	257,592	299,837	759,341	29.56	25,688
2019	554,308.91	122,502	142,592	411,716	29.96	13,742
2020	67,603.02	13,331	15,517	52,086	30.52	1,707
2021	1,282.37	223	260	1,023	30.95	33
2022	9,401.11	1,406	1,637	7,765	31.26	248
2023	741.59	92	107	635	31.60	20
2024	58,212.26	5,763	6,708	51,504	31.84	1,618
2025	801.45	59	69	733	31.75	23
2026	1,001,471.32	45,667	53,156	948,315	31.39	30,211
2027	1,236,609.04	20,528	23,895	1,212,714	29.62	40,942
	19,993,627.77	8,778,887	10,213,070	9,780,558		392,630
	42,670,640.79	19,107,009	22,284,010	20,386,631		797,604

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.6 1.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,694	1,746	223	6.28	36
1967	207.34	177	182	25	6.59	4
1968	820.82	695	716	105	6.90	15
1969	4,348.68	3,651	3,763	586	7.22	81
1970	585.40	487	502	83	7.55	11
1971	1,925.29	1,588	1,637	289	7.89	37
1972	16,780.77	13,708	14,127	2,653	8.24	322
2004	19,260.94	9,896	10,199	9,062	22.00	412
2005	22,925.98	11,376	11,724	11,202	22.59	496
	68,823.91	43,272	44,596	24,228		1,414

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.1 2.05

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1929	141.00	141	141			
1955	2,275.45	2,017	2,074	201	5.11	39
1956	989.22	871	896	93	5.37	17
1957	545.83	478	492	54	5.63	10
1958	236.59	206	212	25	5.90	4
1959	739.15	638	656	83	6.18	13
1960	6,231.82	5,337	5,489	743	6.46	115
1961	5,465.73	4,647	4,779	687	6.74	102
1962	1,776.66	1,499	1,542	235	7.03	33
1963	1,519.13	1,272	1,308	211	7.33	29
1964	1,895.48	1,575	1,620	276	7.62	36
1965	611.14	503	517	94	7.93	12
1966	1,500.19	1,225	1,260	240	8.24	29
1967	7,810.50	6,325	6,505	1,306	8.56	153
1968	5,156.86	4,139	4,257	900	8.88	101
1969	2,743.23	2,182	2,244	499	9.21	54
1970	1,104.82	871	896	209	9.54	22
1971	31,924.90	24,908	25,616	6,309	9.89	638
1972	2,029.09	1,567	1,612	418	10.24	41
1973	5,741.28	4,388	4,513	1,229	10.61	116
1974	677.56	512	527	151	10.98	14
1975	501.75	375	386	116	11.36	10
1976	3,733.18	2,758	2,836	897	11.76	76
1977	1,421.54	1,037	1,066	355	12.16	29
1978	182.88	132	136	47	12.57	4
1979	5,235.99	3,723	3,829	1,407	13.00	108
1980	17,091.10	11,987	12,328	4,764	13.44	354
1981	121,509.06	84,003	86,389	35,120	13.89	2,528
1982	95,200.74	74,095	76,200	19,001	12.89	1,474
1983	6,768.10	5,211	5,359	1,409	13.22	107
1984	6,649.28	5,061	5,205	1,445	13.57	106
1985	25,257.56	18,994	19,534	5,724	13.93	411
1986	23,743.92	17,533	18,031	5,713	14.61	391
1987	25,830.88	18,818	19,353	6,478	15.00	432
1988	26,270.40	18,870	19,406	6,864	15.39	446
1989	52,802.47	37,363	38,424	14,378	15.81	909
1990	55,497.04	38,659	39,757	15,740	16.22	970
1991	30,826.21	21,119	21,719	9,107	16.66	547
1992	56,752.96	38,212	39,297	17,456	17.10	1,021
1993	45,455.69	30,046	30,899	14,556	17.56	829
1994	30,338.27	19,671	20,230	10,108	18.03	561

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1995	22,678.63	14,408	14,817	7,861	18.51	425
1996	22,335.06	13,890	14,285	8,050	19.00	424
1997	8,544.26	5,195	5,343	3,202	19.50	164
1998	8,784.27	5,216	5,364	3,420	20.01	171
1999	13,041.26	7,552	7,767	5,275	20.53	257
2000	2,551.99	1,446	1,487	1,065	20.83	51
2004	347.18	175	180	167	22.83	7
2005	3,317.00	1,616	1,662	1,655	23.41	71
2006	3,670.43	1,732	1,781	1,889	23.79	79
2010	54.74	22	23	32	25.60	1
2012	115,202.00	42,498	43,705	71,497	26.52	2,696
2013	22,348.33	7,809	8,031	14,318	27.00	530
2014	10,178.04	3,367	3,463	6,715	27.31	246
2015	1,657.77	514	529	1,129	27.82	41
2017	320.08	86	88	232	28.41	8
2018	4,740.95	1,176	1,209	3,532	28.81	123
2019	1,261.22	285	293	968	29.09	33
2024	123,717.60	13,164	13,538	110,180	29.39	3,749
2025	103,838.99	8,255	8,489	95,349	28.95	3,294
	1,180,774.45	641,374	659,589	521,185		25,261

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.6 2.14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	285	291			
1990	10,556.06	10,263	10,556			
1991	4,510.10	4,349	4,510			
1992	3,050.56	2,914	3,051			
1993	5,858.48	5,558	5,858			
1994	335.37	316	335			
1997	104.02	95	104			
	24,705.16	23,780	24,705			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,369	1,369			
1952	1,125.65	1,126	1,126			
1953	30,125.92	30,073	30,126			
1954	5,517.65	5,478	5,518			
1955	601.79	594	602			
1956	8,337.58	8,175	8,338			
1957	1,905.18	1,856	1,905			
1958	651.12	630	651			
1959	15,785.61	15,162	15,786			
1960	2,005.39	1,912	2,005			
1961	1,960.14	1,856	1,960			
1962	288.11	271	288			
1963	1,039.65	971	1,040			
1964	5,769.25	5,355	5,769			
1965	1,751.72	1,616	1,752			
1966	3,912.12	3,588	3,912			
1967	4,863.78	4,435	4,864			
1968	8,062.42	7,307	8,062			
1969	1,581.42	1,424	1,581			
1970	2,285.43	2,045	2,285			
1971	10,974.98	9,762	10,975			
1972	4,046.99	3,576	4,047			
1974	1,652.12	1,440	1,652			
1975	8,480.27	7,338	8,480			
1976	7,949.17	6,828	7,949			
1977	2,458.86	2,096	2,459			
1978	1,265.56	1,070	1,266			
1979	752.79	631	753			
1980	1,718.37	1,427	1,718			
1981	10,162.67	8,359	10,163			
1982	12,027.61	10,450	12,028			
1983	1,755.64	1,507	1,756			
1984	30,831.09	26,268	30,831			
1985	13,068.42	10,988	13,068			
1986	19,569.87	16,306	19,570			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1987	23,586.65	19,461	23,587			
1988	13,276.05	10,787	13,276			
1989	15,968.66	12,826	15,937	32	9.37	3
1990	33,323.13	26,315	32,697	626	9.92	63
1991	26,014.16	20,275	25,192	822	10.26	80
1992	15,045.39	11,508	14,299	746	10.83	69
1993	23,968.53	17,979	22,339	1,629	11.41	143
1994	51,100.60	37,722	46,870	4,230	11.79	359
1995	69,990.02	50,561	62,823	7,167	12.39	578
1996	45,414.72	32,217	40,030	5,384	12.80	421
1997	84,495.34	58,530	72,725	11,771	13.42	877
1998	75,399.07	50,947	63,303	12,096	14.04	862
1999	119,656.29	79,093	98,275	21,382	14.49	1,476
2000	199,968.82	128,600	159,788	40,181	15.12	2,657
2001	116,038.59	72,501	90,084	25,955	15.76	1,647
2002	42,457.03	25,835	32,101	10,356	16.24	638
2003	222,013.40	130,832	162,562	59,452	16.90	3,518
2004	109,705.10	62,488	77,643	32,062	17.57	1,825
2005	70,405.76	38,850	48,272	22,134	18.07	1,225
2006	85,043.37	45,175	56,131	28,912	18.75	1,542
2007	37,304.93	19,037	23,654	13,651	19.43	703
2008	97,908.80	48,494	60,255	37,654	19.87	1,895
2009	42,499.78	20,204	25,104	17,396	20.41	852
2011	14,980.73	6,451	8,016	6,965	21.82	319
2013	30,446.98	11,743	14,591	15,856	23.09	687
2018	12,429.20	3,294	4,093	8,336	26.34	316
2019	31,358.25	7,517	9,340	22,018	26.96	817
2020	191,812.76	41,010	50,956	140,857	27.59	5,105
2022	92,398.23	14,784	18,369	74,029	28.87	2,564
2023	200,050.99	26,567	33,010	167,041	29.40	5,682
2024	76,548.71	8,038	9,987	66,561	29.83	2,231
2025	66,450.74	5,064	6,292	60,159	30.29	1,986
	2,602,976.26	1,388,256	1,687,515	915,461		41,140
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	433	461			
1976	21,500.00	18,468	21,500			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1984	1,544.96	1,316	1,545			
1987	5,496.89	4,535	5,497			
1988	2,425.60	1,971	2,426			
1997	821.60	569	805	17	13.42	1
2008	85,066.24	42,133	59,575	25,491	19.87	1,283
	117,316.10	69,425	91,808	25,508		1,284
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1914	0.25		0			
1919	46.40	46	46			
1920	65.00	65	65			
1924	288.57	289	289			
1926	8.25	8	8			
1927	265.80	266	266			
1928	32.00	32	32			
1929	401.84	402	402			
1930	576.33	576	576			
1931	862.24	862	862			
1932	179.53	180	180			
1935	339.96	340	340			
1936	180.10	180	180			
1937	702.11	702	702			
1938	70.20	70	70			
1939	114.20	114	114			
1941	93.19	93	93			
1946	107.86	108	108			
1947	228.20	228	228			
1950	115.54	116	116			
1951	399.62	400	400			
1953	526.32	525	526			
1954	866.71	860	867			
1955	3,485.13	3,440	3,485			
1956	166.98	164	167			
1957	807.41	786	807			
1958	3,980.48	3,850	3,980			
1959	3,557.12	3,417	3,557			
1960	940.90	897	941			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1961	2,160.12	2,045	2,160			
1962	2,440.64	2,295	2,441			
1963	1,463.53	1,367	1,464			
1964	852.14	791	852			
1965	4,391.44	4,052	4,391			
1966	7,725.03	7,086	7,725			
1967	9,375.01	8,548	9,375			
1968	1,802.13	1,633	1,802			
1969	4,312.49	3,884	4,312			
1970	727.19	651	727			
1971	12,970.95	11,538	12,971			
1972	4,161.73	3,677	4,162			
1973	5,521.13	4,846	5,521			
1974	4,072.92	3,550	4,073			
1975	1,691.94	1,464	1,690	2	5.39	
1976	2,859.26	2,456	2,835	24	5.64	4
1977	9,079.27	7,738	8,933	146	5.91	25
1978	8,076.46	6,827	7,881	195	6.19	32
1979	16,025.59	13,429	15,503	522	6.48	81
1980	16,463.34	13,673	15,785	678	6.78	100
1981	18,913.59	15,556	17,959	955	7.10	135
1982	17,303.36	15,033	17,303			
1983	24,489.09	21,021	24,269	220	7.30	30
1984	30,607.35	26,077	30,106	502	7.51	67
1985	47,810.95	40,199	46,410	1,401	8.00	175
1986	41,095.26	34,241	39,531	1,564	8.26	189
1987	31,108.85	25,668	29,634	1,475	8.53	173
1988	67,276.33	54,662	63,107	4,169	9.06	460
1989	73,855.80	59,321	68,486	5,370	9.37	573
1990	72,040.64	56,890	65,679	6,361	9.92	641
1991	46,648.02	36,357	41,974	4,674	10.26	456
1992	72,629.85	55,555	64,138	8,492	10.83	784
1993	50,628.58	37,976	43,843	6,785	11.41	595
1994	79,302.27	58,541	67,585	11,717	11.79	994
1995	207,257.72	149,723	172,855	34,403	12.39	2,777
1996	83,557.81	59,276	68,434	15,124	12.80	1,182
1997	20,844.66	14,439	16,670	4,175	13.42	311
1998	283,838.00	191,789	221,420	62,418	14.04	4,446
1999	62,321.83	41,195	47,560	14,762	14.49	1,019
2000	24,248.93	15,594	18,003	6,246	15.12	413
2006	20,518.49	10,899	12,583	7,936	18.75	423

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
2010	4,783.98	2,168	2,503	2,281	21.11	108
2014	897.06	326	376	521	23.67	22
2016	116,605.62	36,742	42,419	74,187	25.00	2,967
2017	219,792.43	63,696	73,537	146,256	25.73	5,684
2018	159,592.89	42,292	48,826	110,767	26.34	4,205
2019	186,196.01	44,631	51,526	134,670	26.96	4,995
2020	386,652.62	82,666	95,438	291,215	27.59	10,555
2022	1,515.12	242	279	1,236	28.87	43
	2,587,913.66	1,413,341	1,626,466	961,448		44,664
	5,308,206.02	2,871,022	3,405,789	1,902,417		87,088
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.8	1.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,727	10,727			
2001	13,978.74	13,979	13,979			
2002	7,564.41	7,564	7,564			
2003	93,599.07	90,791	91,290	2,309	0.75	2,309
	1,490,664.11	1,487,856	1,488,355	2,309		2,309

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.0 0.15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1950	1,418.30	1,120	1,092	326	16.29	20
1951	3,057.27	2,409	2,350	708	16.35	43
1952	6,785.09	5,331	5,199	1,586	16.41	97
1953	9,470.29	7,420	7,237	2,234	16.47	136
1954	148,376.60	115,944	113,081	35,296	16.52	2,137
1955	623.35	486	474	149	16.58	9
1956	572.21	445	434	138	16.63	8
1957	2,308.79	1,788	1,744	565	16.69	34
1958	1,215.66	939	916	300	16.74	18
1959	1,679.61	1,293	1,261	419	16.79	25
1960	3,752.59	2,879	2,808	945	16.84	56
1961	12,080.86	9,237	9,009	3,072	16.89	182
1962	8,890.78	6,775	6,608	2,283	16.93	135
1963	6,367.07	4,835	4,716	1,651	16.98	97
1964	8,268.08	6,256	6,102	2,167	17.02	127
1965	4,342.79	3,274	3,193	1,150	17.07	67
1966	268.19	201	196	72	17.11	4
1967	378.60	283	276	103	17.15	6
1968	1,406.73	1,048	1,022	385	17.19	22
1969	5,978.81	4,436	4,326	1,652	17.23	96
1970	2,406.17	1,778	1,734	672	17.27	39
1971	1,189.68	875	853	336	17.31	19
1972	486.10	356	347	139	17.34	8
1973	2,639.33	1,924	1,876	763	17.38	44
1978	1,473.74	1,047	1,021	453	17.54	26
1980	5,454.93	3,831	3,736	1,719	17.60	98
1983	13,725.72	9,839	9,596	4,130	17.48	236
1985	11,458.12	8,085	7,885	3,573	17.63	203
1988	48,662.92	33,616	32,786	15,877	17.57	904
1989	7,809.36	5,347	5,215	2,594	17.61	147
1990	115,039.08	77,996	76,070	38,969	17.69	2,203
1992	44,945.57	29,943	29,204	15,742	17.66	891
1994	1,632,881.06	1,064,149	1,037,872	595,010	17.77	33,484
1995	21,056.06	13,581	13,246	7,810	17.75	440
1996	2,152.61	1,372	1,338	814	17.77	46
1998	24,719.58	15,400	15,020	9,700	17.70	548
2000	8,019.38	4,852	4,732	3,287	17.79	185
2001	23,252.05	13,856	13,514	9,738	17.80	547
2002	45,412.44	26,603	25,946	19,466	17.85	1,091
2003	132,431.24	76,439	74,551	57,880	17.76	3,259

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
2004	70,857.23	40,034	39,045	31,812	17.90	1,777
2005	58,347.86	32,325	31,527	26,821	17.91	1,498
2012	72,929.76	33,912	33,075	39,855	17.83	2,235
2014	121,308.92	52,236	50,946	70,363	17.85	3,942
2015	9,229.51	3,795	3,701	5,528	17.90	309
2016	79,291.86	31,003	30,237	49,054	17.91	2,739
2018	20,342.64	7,055	6,881	13,462	17.90	752
2021	3,870.88	1,034	1,008	2,862	17.83	161
2022	84,995.42	20,101	19,605	65,391	17.76	3,682
2023	1,246,040.94	252,323	246,092	999,949	17.72	56,431
2024	348,224.88	57,666	56,242	291,983	17.64	16,552
2025	105,549.28	13,173	12,848	92,702	17.54	5,285
2026	2,681,676.48	213,461	208,190	2,473,487	17.33	142,729
2027	2,386,312.86	69,203	67,494	2,318,819	16.71	138,768
	9,661,435.33	2,394,609	2,335,478	7,325,957		424,597
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1950	663.78	654	638	26	0.99	26
1951	818.32	806	786	32	0.99	32
1955	797,824.96	785,538	766,140	31,685	0.99	31,685
1956	1,042.86	1,027	1,002	41	0.99	41
1957	10,205.79	10,045	9,797	409	0.99	409
1958	2,472.20	2,433	2,373	99	0.99	99
1959	5,162.34	5,079	4,954	209	0.99	209
1960	4,927.91	4,847	4,727	201	1.00	201
1961	537,246.65	528,296	515,250	21,996	1.00	21,996
1962	337.70	332	324	14	1.00	14
1963	276.86	272	265	12	1.00	12
1966	3,845.74	3,777	3,684	162	1.00	162
1967	2,780.90	2,731	2,664	117	1.00	117
1969	863.58	848	827	37	1.00	37
1970	8,005.15	7,855	7,661	344	1.00	344
1971	18,339.63	17,990	17,546	794	1.00	794
1972	3,377.17	3,312	3,230	147	1.00	147
1973	2,851.84	2,796	2,727	125	1.00	125

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1974	1,209,064.72	1,184,883	1,155,624	53,441	1.00	53,441
1975	22,680.36	22,219	21,670	1,010	1.00	1,010
1976	32,687.24	32,012	31,222	1,466	1.00	1,466
1977	35,120.54	34,382	33,533	1,588	1.00	1,588
1978	14,226.60	13,922	13,578	648	1.00	648
1979	147,786.61	144,565	140,995	6,791	1.00	6,791
1980	458,900.86	448,713	437,633	21,268	1.00	21,268
1981	57,250.91	55,956	54,574	2,677	1.00	2,677
1982	38,492.04	37,622	36,693	1,799	1.05	1,713
1983	2,906.83	2,843	2,773	134	1.00	134
1984	89,508.75	87,486	85,326	4,183	1.00	4,183
1985	30,566.50	29,833	29,096	1,470	1.04	1,413
1986	139,715.34	136,586	133,213	6,502	0.95	6,502
1987	3,321.78	3,235	3,155	167	1.07	156
1988	2,087.03	2,032	1,982	105	1.07	98
1989	961,772.17	938,113	914,948	46,825	0.96	46,825
1990	708,583.10	688,884	671,873	36,710	1.07	34,308
1991	55,190.91	53,618	52,294	2,897	1.06	2,733
1992	344,198.58	334,871	326,602	17,597	0.98	17,597
1993	36,928.07	35,920	35,033	1,895	0.96	1,895
1994	335,214.50	325,460	317,423	17,791	1.00	17,791
1995	34,488.45	33,478	32,651	1,837	0.97	1,837
1996	43,259.00	41,909	40,874	2,385	1.01	2,361
1997	10,198.52	9,872	9,628	570	1.00	570
1998	247,376.09	239,510	233,596	13,780	0.96	13,780
2000	1,456,245.66	1,404,695	1,370,008	86,238	1.00	86,238
2001	375,274.89	361,540	352,612	22,663	1.00	22,663
2002	173,333.42	166,747	162,629	10,704	1.00	10,704
2003	199,964.75	192,026	187,284	12,681	1.00	12,681
2004	200,000.60	191,581	186,850	13,150	1.02	12,892
2005	507,153.85	485,245	473,263	33,891	1.00	33,891
2006	72,579.79	69,248	67,538	5,042	1.02	4,943
2007	744,341.85	709,953	692,422	51,920	0.98	51,920
2008	546,752.51	520,290	507,442	39,310	0.99	39,310
2009	132,073.30	125,338	122,243	9,830	0.99	9,830
2010	92,064.49	87,167	85,015	7,050	0.98	7,050
2011	74,956.19	70,624	68,880	6,076	1.01	6,016
2012	249,051.61	233,934	228,157	20,894	1.00	20,894
2013	35,934.67	33,606	32,776	3,159	1.00	3,159
2014	290,643.52	270,734	264,049	26,595	0.99	26,595

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
2015	382,288.92	354,076	345,333	36,956	1.00	36,956
2016	807,917.85	743,284	724,930	82,988	1.00	82,988
2017	171,950.77	157,077	153,198	18,753	0.99	18,753
2018	1,011,279.50	915,612	893,002	118,277	0.99	118,277
2019	2,119,266.30	1,896,743	1,849,906	269,361	1.00	269,361
2020	9,673.03	8,539	8,328	1,345	1.00	1,345
2021	237,128.18	205,614	200,537	36,592	1.00	36,592
2022	1,975,968.59	1,672,460	1,631,161	344,808	1.00	344,808
2023	1,261,950.19	1,033,032	1,007,523	254,427	1.00	254,427
2024	483,485.27	376,152	366,863	116,622	1.00	116,622
2025	3,069,083.76	2,193,781	2,139,609	929,475	1.00	929,475
2026	471,640.10	283,173	276,180	195,460	1.00	195,460
	23,614,572.44	21,078,833	20,558,321	3,056,251		3,053,085
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
1969	6,798.01	3,791	3,697	3,101	36.14	86
1970	3,383.06	1,869	1,823	1,560	36.39	43
1989	25,957.50	13,106	12,782	13,175	37.51	351
1992	58,567.66	28,282	27,584	30,984	37.74	821
1994	10,549.87	4,911	4,790	5,760	38.18	151
2002	4,127.48	1,626	1,586	2,542	38.85	65
2005	2,644.58	959	935	1,709	39.10	44
2010	2,788.23	859	838	1,950	39.32	50
2011	36,615.99	10,816	10,549	26,067	39.36	662
2014	167,443.92	42,732	41,677	125,767	39.41	3,191
2015	204,441.65	49,066	47,854	156,587	39.58	3,956
2016	539,847.11	121,682	118,677	421,170	39.52	10,657
2018	842,885.66	164,194	160,139	682,746	39.28	17,382
2019	4,975.51	888	866	4,109	39.12	105
2021	103,857.62	14,852	14,485	89,372	38.95	2,295
2022	24,312.57	3,022	2,947	21,365	38.75	551

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
2023	14,599,888.58	1,530,068	1,492,285	13,107,603	38.42	341,166
2024	12,255,071.05	1,034,328	1,008,787	11,246,284	37.99	296,033
2025	1,920,001.92	120,576	117,599	1,802,403	37.34	48,270
	30,814,157.97	3,147,627	3,069,901	27,744,257		725,879
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1933	657.93	559	545	113	12.47	9
1992	1,969,044.37	1,409,048	1,374,253	594,791	14.01	42,455
1993	15,226.14	10,795	10,528	4,698	14.06	334
1994	10,056.65	7,056	6,882	3,175	14.14	225
2000	1,880.00	1,235	1,205	675	14.24	47
2001	34,203.52	22,178	21,630	12,573	14.23	884
2021	22,887.76	7,187	7,010	15,878	14.20	1,118
2022	3,729.30	1,042	1,016	2,713	14.19	191
2023	23,764.21	5,732	5,590	18,174	14.16	1,283
2024	18,478.82	3,666	3,575	14,903	14.14	1,054
2025	79,939.97	12,071	11,773	68,167	14.06	4,848
	2,179,868.67	1,480,569	1,444,008	735,861		52,448
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2009	4,566,421.06	1,790,950	1,746,725	2,819,696	28.67	98,350
2011	167,660.30	61,129	59,619	108,041	28.75	3,758
2021	83,191.47	15,465	15,083	68,108	28.47	2,392
2022	1,276,178.42	207,762	202,632	1,073,547	28.28	37,961
2023	117,038.23	16,116	15,718	101,320	28.18	3,595

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2024	86,972.30	9,680	9,441	77,531	27.95	2,774
2025	115,732.05	9,606	9,369	106,363	27.62	3,851
2027	2,665,410.93	51,176	49,912	2,615,499	25.54	102,408
	9,078,604.76	2,161,884	2,108,499	6,970,106		255,089
UGI-GAS - GAS TRAINING CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2021	31,183,853.56	4,683,815	4,568,155	26,615,699	36.79	723,449
2022	3,002,042.24	391,466	381,799	2,620,243	36.69	71,416
2023	29,706.91	3,274	3,193	26,514	36.32	730
2024	21,138.08	1,873	1,827	19,311	36.02	536
2025	30,709.16	2,027	1,977	28,732	35.38	812
	34,267,449.95	5,082,455	4,956,951	29,310,499		796,943
UGI-GAS - HAZLETON						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2027	8,394,171.24	129,270		8,394,171	31.97	262,564
	8,394,171.24	129,270		8,394,171		262,564
UGI-GAS - WELLSBORO						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2026	5,893,983.14	245,779		5,893,983	34.47	170,989
2027	238,290.00	3,670		238,290	31.97	7,454
	6,132,273.14	249,449		6,132,273		178,443

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			
1938	143.77	144	144			
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	401	401			
1949	1,806.43	1,806	1,806			
1950	2,196.55	2,197	2,197			
1951	233.36	233	233			
1953	27,799.96	27,744	27,024	776	0.08	776
1954	20,454.90	20,307	19,780	675	0.29	675
1955	3,292.27	3,249	3,165	128	0.52	128
1957	1,355.54	1,320	1,286	70	1.04	67
1958	5,763.15	5,574	5,429	334	1.31	255
1959	1,958.52	1,881	1,832	126	1.58	80
1960	3,574.90	3,409	3,321	254	1.86	137
1961	649.28	615	599	50	2.14	23
1962	9,412.34	8,843	8,613	799	2.42	330
1963	12,936.88	12,064	11,751	1,186	2.70	439
1964	3,052.55	2,824	2,751	302	2.99	101
1966	2,516.15	2,292	2,233	284	3.57	80
1967	1,274.89	1,152	1,122	153	3.86	40
1968	419.83	376	366	54	4.15	13
1970	731.03	644	627	104	4.74	22
1971	10,643.95	9,303	9,062	1,582	5.04	314
1972	1,090.13	945	920	170	5.34	32
1975	164.27	139	135	29	6.27	5

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1976	24,200.07	20,213	19,688	4,512	6.59	685
1977	7,165.00	5,924	5,770	1,395	6.93	201
1978	8,046.84	6,584	6,413	1,634	7.27	225
1979	4,081.97	3,303	3,217	865	7.63	113
1980	13,629.88	10,904	10,621	3,009	8.00	376
1983	369.74	311	303	67	8.38	8
1985	27,096.76	22,209	21,633	5,464	9.30	588
1986	5,526.05	4,490	4,373	1,153	9.51	121
1988	338.67	268	261	78	10.26	8
1989	19,959.70	15,575	15,171	4,789	10.77	445
1990	1,194.94	917	893	302	11.29	27
1991	5,163.03	3,912	3,810	1,353	11.60	117
1992	7,676.31	5,710	5,562	2,115	12.14	174
1994	38,494.90	27,647	26,929	11,566	13.05	886
1995	28,542.82	20,160	19,637	8,906	13.41	664
1997	46,847.50	31,744	30,920	15,927	14.39	1,107
1998	39,421.11	26,057	25,381	14,040	15.00	936
1999	72,667.26	47,008	45,788	26,879	15.42	1,743
2000	38,962.96	24,527	23,890	15,073	16.04	940
2001	110,913.42	68,123	66,355	44,559	16.49	2,702
2002	39,331.76	23,438	22,830	16,502	17.12	964
2003	35,150.00	20,373	19,844	15,306	17.59	870
2004	52,683.27	29,518	28,752	23,931	18.24	1,312
2005	302,659.69	164,314	160,049	142,611	18.73	7,614
2006	139,043.00	72,984	71,090	67,953	19.23	3,534
2007	78,002.02	39,485	38,460	39,542	19.75	2,002
2011	148,951.37	63,900	62,241	86,710	21.96	3,949
2012	1,935.54	789	769	1,167	22.52	52
2013	5,265.73	2,031	1,978	3,287	23.09	142
2014	187,584.86	68,375	66,600	120,985	23.54	5,140
2015	20,002.66	6,825	6,648	13,355	24.13	553
2016	52,555.80	16,681	16,248	36,308	24.73	1,468
2017	28,421.86	8,356	8,139	20,283	25.21	805
2018	276,078.65	74,486	72,553	203,526	25.71	7,916
2019	737,164.05	180,458	175,774	561,390	26.22	21,411
2020	469,675.04	102,859	100,189	369,486	26.75	13,813
2021	305,923.54	59,043	57,510	248,413	27.17	9,143
2022	4,000.00	664	647	3,353	27.61	121

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2023	4,502.00	624	608	3,894	27.97	139
2024	174,756.78	19,328	18,826	155,930	28.15	5,539
2025	11,517.54	935	911	10,607	28.27	375
	3,754,319.25	1,475,456	1,439,022	2,315,297		102,445
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	100,411.50	75,710	90,054	10,358	18.00	575
1961	86,436.52	64,935	77,237	9,199	18.06	509
1962	140,444.44	105,134	125,052	15,392	18.11	850
1963	9,434.86	7,036	8,369	1,066	18.17	59
1964	3,671.75	2,728	3,245	427	18.22	23
1965	476.79	353	420	57	18.27	3
1966	296.05	218	259	37	18.32	2
1967	856.55	629	748	108	18.37	6
1968	3,554.78	2,597	3,089	466	18.42	25
1969	658.45	479	570	89	18.46	5
1970	2,315.32	1,677	1,995	321	18.51	17
1971	74,528.08	53,726	63,905	10,623	18.55	573
1972	5,258.19	3,773	4,488	770	18.59	41
1973	5,840.21	4,169	4,959	881	18.64	47
1974	1,073.37	762	906	167	18.68	9
1975	20,035.73	14,154	16,836	3,200	18.72	171
1976	98,030.00	68,892	81,944	16,086	18.75	858
1977	261,557.32	182,758	217,383	44,174	18.79	2,351
1978	14,809.44	10,288	12,237	2,572	18.83	137
1979	31,206.19	21,550	25,633	5,573	18.86	295
1980	50,079.98	34,365	40,876	9,204	18.90	487
1981	48,797.03	33,272	39,576	9,221	18.93	487
1982	16,044.38	11,326	13,472	2,573	18.85	136
1983	15,867.03	11,164	13,279	2,588	18.64	139
1984	47,451.19	33,040	39,300	8,151	18.86	432
1985	68,532.32	47,486	56,483	12,050	18.73	643
1986	219,686.96	151,342	180,015	39,672	18.63	2,129
1987	95,434.84	64,915	77,214	18,221	18.92	963
1988	78,704.24	53,133	63,199	15,505	18.89	821
1989	133,439.37	89,324	106,247	27,192	18.89	1,439

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1990	1,470.19	975	1,160	310	18.93	16
1991	12,720.31	8,346	9,927	2,793	19.00	147
1992	107,988.13	70,419	83,760	24,228	18.81	1,288
1993	238,332.48	153,462	182,537	55,796	18.94	2,946
1994	9,203.68	5,845	6,952	2,251	19.10	118
1995	132,758.96	83,492	99,310	33,449	19.03	1,758
1996	77,419.94	48,147	57,269	20,151	19.00	1,061
1997	4,612,955.08	2,832,816	3,369,516	1,243,439	19.01	65,410
1998	279,913.28	169,487	201,598	78,316	19.06	4,109
1999	84,662.32	50,467	60,028	24,634	19.14	1,287
2000	89,524.70	52,694	62,677	26,847	19.05	1,409
2001	723,658.18	417,913	497,090	226,568	19.20	11,800
2002	42,168.49	23,956	28,495	13,674	19.20	712
2003	180,364.23	100,607	119,668	60,696	19.23	3,156
2004	145,827.87	80,016	95,176	50,652	19.12	2,649
2005	166,648.91	89,357	106,286	60,362	19.24	3,137
2006	139,708.19	73,333	87,227	52,482	19.23	2,729
2007	875,254.94	450,231	535,531	339,724	19.12	17,768
2008	79,132.07	39,811	47,354	31,779	19.26	1,650
2009	54,018.52	26,480	31,497	22,522	19.24	1,171
2010	195,845.69	93,223	110,885	84,961	19.26	4,411
2011	314,356.66	145,233	172,749	141,608	19.21	7,372
2012	49,325.07	22,019	26,191	23,134	19.22	1,204
2013	122,445.69	52,725	62,714	59,732	19.17	3,116
2014	163,675.40	67,614	80,424	83,251	19.18	4,341
2015	94,729.99	37,305	44,373	50,357	19.24	2,617
2016	607,579.20	227,781	270,936	336,643	19.17	17,561
2017	14,859.54	5,257	6,253	8,607	19.18	449
2025	4,021.69	473	563	3,459	18.78	184
2027	293,024.46	7,970	9,480	283,544	17.85	15,885
	11,548,526.74	6,588,389	7,836,613	3,711,914		195,693
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	25,471	27,375			
1961	2,250.14	2,092	2,250			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1962	11,395.40	10,585	11,395			
1964	212.41	197	212			
1965	479.69	444	480			
1972	4,846.95	4,452	4,847			
1973	59,338.04	54,434	59,338			
1976	674.99	617	675			
1977	9,114.69	8,312	9,115			
1978	24,124.85	21,965	24,125			
1979	540.75	492	541			
1980	8,726.53	7,919	8,727			
1981	52,430.77	47,492	52,431			
1982	22,292.87	20,275	22,293			
1984	11,417.15	10,369	11,417			
1986	31,130.64	28,123	31,131			
1987	11,362.33	10,244	11,362			
1988	15,773.37	14,177	15,773			
1989	8,654.63	7,746	8,655			
1990	94,337.02	84,337	94,337			
1992	6,049.58	5,374	6,050			
1993	1,598.34	1,412	1,598			
1994	38,859.45	34,239	38,859			
1995	4,586.75	4,023	4,587			
1996	1,532.27	1,341	1,532			
1997	1,129.92	984	1,130			
1998	3,483.10	3,026	3,483			
2001	6,551.41	5,607	6,551			
2002	8,685.69	7,391	8,686			
2003	26,975.97	22,765	26,976			
2004	262,708.52	220,491	262,709			
2005	28,203.02	23,471	28,203			
2008	29,302.79	23,829	29,303			
2010	189,349.18	150,760	189,349			
2011	217,404.63	171,097	217,405			
2014	19,697.18	14,812	19,697			
2016	36,430.01	26,226	36,430			
2020	4,772.90	2,993	4,773			
	1,283,798.91	1,079,584	1,283,799			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2001	6,628.41	3,514	4,180	2,448	23.26	105
2002	3,783,335.80	1,968,091	2,341,062	1,442,274	23.29	61,927
2003	87,794.37	44,705	53,177	34,617	23.37	1,481
2004	116,222.01	57,832	68,792	47,430	23.48	2,020
2005	21,321.99	10,390	12,359	8,963	23.41	383
2006	70,501.63	33,559	39,919	30,583	23.39	1,308
2007	23,909.23	11,087	13,188	10,721	23.42	458
2008	36,082.96	16,396	19,503	16,580	23.42	708
2009	2,440.34	1,074	1,278	1,163	23.52	49
2010	44,187.56	18,868	22,444	21,744	23.48	926
2011	22,823.04	9,415	11,199	11,624	23.50	495
2012	5,700.89	2,262	2,691	3,010	23.56	128
2013	10,921.02	4,165	4,954	5,967	23.52	254
2014	82,583.84	30,102	35,807	46,777	23.54	1,987
2015	2,300.95	800	952	1,349	23.47	57
2016	41,558.96	13,669	16,259	25,300	23.47	1,078
2021	94,830.25	20,654	24,568	70,262	23.35	3,009
2022	973,757.93	186,377	221,697	752,061	23.24	32,361
2023	81,823.98	13,329	15,855	65,969	23.12	2,853
2024	301,308.21	39,773	47,310	253,998	23.02	11,034
2025	136,691.16	13,505	16,064	120,627	22.82	5,286
	5,946,724.53	2,499,567	2,973,257	2,973,468		127,907
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
2014	762,683.33	241,923	287,770	474,913	29.06	16,342
2015	31,548.99	9,503	11,304	20,245	29.00	698
2016	12,659.84	3,595	4,276	8,384	28.99	289
2022	24,906.01	4,015	4,776	20,130	28.63	703
2023	68,924.02	9,401	11,183	57,741	28.50	2,026
2025	6,759.94	554	659	6,101	27.99	218
2027	199,272.09	3,786	4,503	194,769	25.82	7,543
	1,106,754.22	272,777	324,471	782,283		27,819

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	272,316.43	238,005	272,316			
1972	796.73	690	797			
1973	1,410.36	1,211	1,410			
1974	13,493.34	11,486	13,493			
1975	143,221.64	120,772	143,222			
1976	277,802.44	232,034	276,838	964	6.59	146
1978	1,751.96	1,434	1,711	41	7.27	6
1983	1,752.80	1,474	1,753			
1984	8,378.41	6,957	8,300	78	8.83	9
1986	1,491.51	1,212	1,446	45	9.51	5
1987	64,176.33	51,405	61,331	2,845	10.00	284
1988	167,135.29	132,505	158,091	9,044	10.26	881
1989	18,409.44	14,365	17,139	1,271	10.77	118
1990	3,305.80	2,537	3,027	279	11.29	25
1992	910.07	677	808	102	12.14	8
1994	8,521.54	6,120	7,302	1,220	13.05	93
1995	473.03	334	398	75	13.41	6
1996	2,278.47	1,574	1,878	401	14.00	29
1997	23,231.33	15,742	18,782	4,450	14.39	309
1998	20,714.41	13,692	16,336	4,379	15.00	292
1999	4,980.08	3,222	3,844	1,136	15.42	74
2000	408,333.59	257,046	306,681	101,653	16.04	6,337
2001	15,804.48	9,707	11,581	4,223	16.49	256
2002	131,353.77	78,274	93,388	37,965	17.12	2,218
2003	14,163.49	8,209	9,794	4,369	17.59	248
2004	40,679.27	22,793	27,194	13,485	18.24	739
2005	19,902.80	10,805	12,891	7,011	18.73	374
2007	62,923.38	31,852	38,003	24,921	19.75	1,262
2008	2,273.79	1,117	1,333	941	20.18	47
2009	9,242.58	4,361	5,203	4,039	20.71	195
2010	66,070.12	29,718	35,456	30,614	21.41	1,430
2011	411,804.61	176,664	210,777	201,027	21.96	9,154
2012	83,921.29	34,206	40,811	43,110	22.52	1,914
2014	113,808.03	41,483	49,493	64,315	23.54	2,732
2015	183,550.09	62,627	74,720	108,830	24.13	4,510
2016	68,269.86	21,669	25,853	42,417	24.73	1,715
2017	413,544.33	121,582	145,059	268,485	25.21	10,650
2018	668,011.43	180,229	215,031	452,981	25.71	17,619
2019	2,142,813.03	524,561	625,852	1,516,961	26.22	57,855
2020	716,100.44	156,826	187,109	528,992	26.75	19,775
2021	1,695,047.58	327,144	390,314	1,304,733	27.17	48,021

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2022	2,083,863.55	346,130	412,966	1,670,897	27.61	60,518
2023	786,100.20	108,953	129,991	656,109	27.97	23,458
2024	856,957.60	94,780	113,082	743,876	28.15	26,425
2025	453,918.49	36,858	43,975	409,943	28.27	14,501
2026	279,207.98	14,184	16,923	262,285	28.00	9,367
2027	399,454.46	7,430	8,865	390,590	26.45	14,767
	13,163,671.65	3,566,656	4,242,569	8,921,103		338,372
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1969	2,453.00	2,214	2,453			
1970	872.29	786	872			
1976	342.77	306	343			
1988	1,813.00	1,587	1,813			
1990	11,104.08	9,637	11,104			
1992	1,829.56	1,574	1,830			
1993	164,577.50	141,487	164,578			
1994	8,948.74	7,647	8,949			
1995	553.43	471	551	2	5.63	
1996	6,824.90	5,780	6,764	61	5.65	11
1997	2,764.61	2,325	2,721	44	5.72	8
1999	58,743.84	48,957	57,290	1,454	5.65	257
2000	1,983.26	1,643	1,923	61	5.64	11
2005	3,338.96	2,660	3,113	226	5.68	40
2006	4,214.76	3,323	3,889	326	5.70	57
2008	49,021.21	37,952	44,412	4,609	5.69	810
2010	2,592.10	1,955	2,288	304	5.70	53
2011	12,791.22	9,519	11,139	1,652	5.67	291
2015	244,901.72	168,370	197,028	47,874	5.68	8,429
2016	106,882.55	71,536	83,712	23,171	5.68	4,079
2017	7,718.68	5,009	5,862	1,857	5.68	327
2018	17,640.50	11,027	12,904	4,737	5.70	831
2021	63,475.20	33,832	39,590	23,885	5.70	4,190

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
2022	2,400.00	1,180	1,381	1,019	5.69	179
2023	7,122.00	3,147	3,683	3,439	5.68	605
2025	3,950.00	1,208	1,414	2,536	5.68	446
	788,859.88	575,132	671,602	117,258		20,624
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1989	98.04	72	84	14	14.10	1
1992	725,697.35	519,309	606,415	119,282	14.01	8,514
1993	3,021.04	2,142	2,501	520	14.06	37
1994	8,335.20	5,848	6,829	1,506	14.14	107
1995	2,607.47	1,816	2,121	487	14.05	35
1996	9,610.58	6,607	7,715	1,895	14.20	133
1998	1,689.35	1,137	1,328	362	14.23	25
2000	409,804.65	269,119	314,260	95,545	14.24	6,710
2002	77,414.37	49,452	57,747	19,668	14.28	1,377
2003	8,225.76	5,186	6,056	2,170	14.21	153
2004	30,259.16	18,785	21,936	8,323	14.20	586
2005	10,831.15	6,603	7,711	3,121	14.25	219
2006	33,782.73	20,243	23,638	10,144	14.21	714
2009	47,875.20	27,011	31,542	16,334	14.29	1,143
2010	16,675.79	9,192	10,734	5,942	14.25	417
2012	6,475.40	3,372	3,938	2,538	14.26	178
2014	116,736.12	56,734	66,250	50,486	14.28	3,535
2015	37,051.71	17,322	20,227	16,824	14.24	1,181
2016	10,247.50	4,572	5,339	4,909	14.27	344
2018	11,836.77	4,735	5,529	6,308	14.25	443
2019	5,766.44	2,157	2,519	3,248	14.23	228
2021	4,196.38	1,318	1,539	2,657	14.20	187
2022	125,784.49	35,144	41,039	84,746	14.19	5,972
2023	61,310.32	14,788	17,268	44,042	14.16	3,110
2024	53,260.70	10,567	12,339	40,921	14.14	2,894
2025	14,236.24	2,150	2,511	11,726	14.06	834
2027	520,587.47	18,533	21,642	498,946	13.54	36,850
	2,353,417.38	1,113,914	1,300,756	1,052,661		75,927

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1960	194.87	144	168	27	19.14	1
1969	315.77	225	263	53	19.67	3
1975	1,603.00	1,109	1,295	308	19.96	15
1981	24,351.34	16,229	18,951	5,400	20.21	267
1986	335.90	226	264	72	20.10	4
1987	89.63	60	70	20	19.99	1
1988	23.00	15	18	5	19.92	
1989	2,017.54	1,320	1,541	476	20.23	24
1991	4,553.54	2,922	3,412	1,141	20.25	56
1992	2,593.29	1,645	1,921	672	20.31	33
1994	18,298.16	11,378	13,286	5,012	20.22	248
1995	4,163.94	2,552	2,980	1,184	20.38	58
1996	8,983.16	5,446	6,359	2,624	20.30	129
1997	10,866.50	6,509	7,601	3,266	20.25	161
1999	505,960.16	294,469	343,861	162,099	20.29	7,989
2000	12,093.15	6,920	8,081	4,012	20.37	197
2002	2,259.00	1,249	1,458	801	20.41	39
2003	6,064.38	3,294	3,847	2,218	20.39	109
2008	181,878.28	88,666	103,538	78,340	20.50	3,821
2014	17,755.02	7,047	8,229	9,526	20.51	464
2017	148,587.20	50,401	58,855	89,732	20.46	4,386
2022	15,225.60	3,240	3,783	11,442	20.34	563
2027	237,853.28	6,113	7,138	230,715	18.96	12,169
	1,206,065.71	511,179	596,921	609,145		30,737
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1928	12,782.61	12,783	12,783			
1929	2,310.28	2,310	2,310			
1930	369.13	369	369			
1931	762.68	763	763			
1936	351.89	352	352			
1937	626.94	627	627			
1938	53.15	53	53			
1939	413.68	414	414			

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1944	17.42	17	17			
1946	1,497.06	1,497	1,497			
1948	136.94	137	137			
1949	3,064.96	3,065	3,065			
1953	104.14	104	104			
1954	3,090.95	3,069	3,091			
1958	9,599.06	9,285	9,599			
1959	25,945.16	24,920	25,945			
1960	1,493.83	1,424	1,494			
1961	1,235.18	1,169	1,235			
1962	579.08	544	579			
1963	705.71	658	706			
1964	816.28	755	816			
1965	1,476.00	1,355	1,476			
1966	99,788.20	90,882	99,788			
1967	22,782.90	20,584	22,783			
1968	4,441.60	3,981	4,442			
1969	1,926.88	1,713	1,927			
1970	1,936.24	1,707	1,936			
1971	4,123.83	3,604	4,124			
1972	2,679.67	2,322	2,680			
1973	3,159.40	2,714	3,159			
1974	12,462.42	10,609	12,425	38	5.95	6
1976	473.34	395	463	11	6.59	2
1977	3,576.03	2,956	3,462	114	6.93	16
1978	413.12	338	396	17	7.27	2
1979	1,277.89	1,034	1,211	67	7.63	9
1980	3,933.34	3,147	3,686	248	8.00	31
1981	4,514.27	3,569	4,180	334	8.38	40
1982	11,172.83	9,454	11,072	101	8.22	12
1983	490.18	412	483	8	8.38	1
1984	12,593.25	10,457	12,247	346	8.83	39
1985	1,004.40	823	964	41	9.30	4
1987	1,752.91	1,404	1,644	109	10.00	11
1988	13,639.92	10,814	12,665	975	10.26	95
1989	1,481.49	1,156	1,354	128	10.77	12
1990	233,015.67	178,816	209,423	23,593	11.29	2,090
1991	43,979.54	33,319	39,022	4,958	11.60	427
1992	17,796.53	13,237	15,503	2,294	12.14	189
1993	111,468.82	81,707	95,692	15,777	12.48	1,264
1994	121,835.57	87,502	102,479	19,356	13.05	1,483

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1995	38,620.32	27,278	31,947	6,673	13.41	498
1996	709,688.50	490,111	574,000	135,688	14.00	9,692
1997	239,281.07	162,137	189,889	49,392	14.39	3,432
1998	245,720.68	162,421	190,222	55,499	15.00	3,700
1999	78,739.32	50,936	59,654	19,085	15.42	1,238
2000	173,336.88	109,116	127,793	45,544	16.04	2,839
2001	48,215.22	29,614	34,683	13,532	16.49	821
2002	58,565.99	34,899	40,872	17,694	17.12	1,034
2003	622,747.11	360,944	422,724	200,023	17.59	11,371
2004	745,439.83	417,670	489,160	256,280	18.24	14,050
2005	264,173.90	143,420	167,968	96,206	18.73	5,136
2006	118,413.15	62,155	72,794	45,619	19.23	2,372
2007	185,482.54	93,891	109,962	75,521	19.75	3,824
2008	812,452.52	399,239	467,574	344,878	20.18	17,090
2009	11,761.13	5,549	6,499	5,262	20.71	254
2010	133,654.24	60,118	70,408	63,246	21.41	2,954
2011	71,114.66	30,508	35,730	35,385	21.96	1,611
2012	72,405.65	29,513	34,565	37,841	22.52	1,680
2013	141,124.08	54,432	63,749	77,375	23.09	3,351
2014	263,668.26	96,107	112,557	151,111	23.54	6,419
2015	293,465.57	100,130	117,269	176,197	24.13	7,302
2016	193,313.90	61,358	71,860	121,454	24.73	4,911
2017	115,544.92	33,970	39,784	75,761	25.21	3,005
2018	289,253.61	78,041	91,399	197,855	25.71	7,696
2019	607,274.97	148,661	174,106	433,169	26.22	16,521
2020	518,447.63	113,540	132,974	385,474	26.75	14,410
2021	741,363.06	143,083	167,574	573,789	27.17	21,118
2022	1,581,378.43	262,667	307,626	1,273,752	27.61	46,134
2023	3,880,410.89	537,825	629,881	3,250,530	27.97	116,215
2024	472,644.85	52,275	61,223	411,422	28.15	14,615
2025	2,731,932.29	221,833	259,803	2,472,130	28.27	87,447
2027	1,275,439.93	23,723	27,784	1,247,656	26.45	47,170
	18,540,227.47	5,241,490	6,120,670	12,419,557		485,643
	183,834,899.24	58,648,840	61,262,838	122,572,061		7,154,215

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.1 3.89

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.3 CNG STATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-S3						
NET SALVAGE PERCENT.. 0						
2026	7,022,613.60	752,824	753,027	6,269,587	12.49	501,969
	7,022,613.60	752,824	753,027	6,269,587		501,969

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5 7.15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	10,904.48	10,632	9,461	1,443	0.50	1,443
2009	196,763.79	182,007	161,966	34,798	1.50	23,199
2010	29,674.64	25,965	23,106	6,569	2.50	2,628
2013	49,177.44	35,654	31,728	17,449	5.50	3,173
2014	164,928.32	111,327	99,069	65,860	6.50	10,132
2015	142,233.63	88,896	79,107	63,126	7.50	8,417
2016	156,448.43	89,958	80,053	76,396	8.50	8,988
2017	694,772.06	364,755	324,591	370,181	9.50	38,966
2018	365,293.03	173,514	154,408	210,885	10.50	20,084
2019	260,157.81	110,567	98,392	161,766	11.50	14,067
2020	246,448.03	92,418	82,242	164,206	12.50	13,136
2021	1,078,784.33	350,605	311,999	766,785	13.50	56,799
2022	104,987.55	28,872	25,693	79,295	14.50	5,469
2023	12,578.55	2,830	2,518	10,060	15.50	649
2024	849.08	149	133	716	16.50	43
2026	50,000.00	3,750	3,337	46,663	18.50	2,522
2027	95,833.33	2,396	2,132	93,701	19.50	4,805
	3,659,834.50	1,674,295	1,489,935	2,169,900		214,520
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	24,417.03	23,807	24,417			
2010	2,239.24	1,959	2,059	180	2.50	72
2011	20,678.25	17,060	17,931	2,747	3.50	785
2014	33,759.66	22,788	23,951	9,809	6.50	1,509
2015	35,177.20	21,986	23,108	12,069	7.50	1,609
2016	233,275.70	134,134	140,981	92,295	8.50	10,858
2017	400,100.57	210,053	220,775	179,326	9.50	18,876
2018	31,187.62	14,814	15,570	15,617	10.50	1,487
2019	69,735.23	29,637	31,150	38,585	11.50	3,355
2020	115,739.37	43,402	45,617	70,122	12.50	5,610
2021	147,329.19	47,882	50,326	97,003	13.50	7,185
2022	100,538.69	27,648	29,059	71,479	14.50	4,930
2023	16,822.55	3,785	3,978	12,844	15.50	829
2024	4,362.42	763	802	3,560	16.50	216

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2025	7,898.56	987	1,037	6,861	17.50	392
2026	50,000.00	3,750	3,941	46,059	18.50	2,490
2027	50,000.00	1,250	1,314	48,686	19.50	2,497
	1,343,261.28	605,705	636,017	707,245		62,700
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	1,926.82	1,782	1,706	221	1.50	147
2013	4,225.61	3,064	2,933	1,293	5.50	235
2014	54,667.08	36,900	35,319	19,348	6.50	2,977
2015	9,361.71	5,851	5,600	3,761	7.50	501
2016	22,950.78	13,197	12,632	10,319	8.50	1,214
2017	31,887.57	16,741	16,024	15,864	9.50	1,670
2018	64,576.87	30,674	29,360	35,217	10.50	3,354
2019	9,728.37	4,135	3,958	5,771	11.50	502
2020	395,875.29	148,453	142,093	253,782	12.50	20,303
2021	6,256.54	2,033	1,946	4,311	13.50	319
2022	279,971.38	76,992	73,693	206,278	14.50	14,226
	881,428.02	339,822	325,263	556,165		45,448
	5,884,523.80	2,619,822	2,451,214	3,433,310		322,668

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6 5.48

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	18,196.00	13,647	12,194	6,002	2.50	2,401
2021	41,085.52	26,706	23,863	17,223	3.50	4,921
	59,281.52	40,353	36,057	23,225		7,322
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	2,800.72	2,661	2,456	345	0.50	345
2019	4,541.15	3,860	3,562	979	1.50	653
2021	79,835.69	51,893	47,886	31,949	3.50	9,128
2023	2,910.37	1,310	1,209	1,702	5.50	309
2026	50,000.00	7,500	6,921	43,079	8.50	5,068
2027	50,000.00	2,500	2,307	47,693	9.50	5,020
	190,087.93	69,724	64,341	125,747		20,523
	249,369.45	110,077	100,398	148,972		27,845

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4 11.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	8,449,684.03	7,604,716	7,482,586	967,098	0.50	967,098
2024	105,727.22	74,009	72,820	32,907	1.50	21,938
2025	2,608,891.49	1,304,446	1,283,497	1,325,395	2.50	530,158
2026	2,467,186.26	740,156	728,269	1,738,917	3.50	496,833
	13,631,489.00	9,723,327	9,567,172	4,064,317		2,016,027

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.0 14.79

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.41 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	985,498.08	837,673	890,044	95,454	1.50	63,636
2020	17,620.50	13,215	14,041	3,579	2.50	1,432
2021	44,109.42	28,671	30,463	13,646	3.50	3,899
2022	240,887.73	132,488	140,771	100,117	4.50	22,248
2023	1,660,917.30	747,413	794,141	866,776	5.50	157,596
2024	2,425,842.93	849,045	902,127	1,523,716	6.50	234,418
2025	22,628.43	5,657	6,011	16,618	7.50	2,216
	5,397,504.39	2,614,162	2,777,598	2,619,906		485,445

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4 8.99

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.42 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	142,364.69	137,620	138,680	3,685	0.50	3,685
2014	495,556.48	446,001	449,437	46,120	1.50	30,747
2022	1,468,239.56	538,359	542,506	925,734	9.50	97,446
2023	33,630,977.05	10,089,293	10,167,011	23,463,966	10.50	2,234,663
2024	8,239,887.66	1,922,613	1,937,423	6,302,465	11.50	548,040
	43,977,025.44	13,133,886	13,235,056	30,741,969		2,914,581

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.5 6.63

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	794,926.72	604,542	746,381	48,546	2.36	20,570
2021	1,291,033.02	929,027	1,146,997	144,036	2.53	56,931
2022	422,631.37	279,402	344,956	77,675	2.82	27,544
2023	231,386.91	134,204	165,691	65,696	3.26	20,152
2024	218,051.69	104,011	128,414	89,637	3.84	23,343
	2,958,029.71	2,051,186	2,532,440	425,590		148,540
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	303,139.78	247,665	271,610	31,530	2.13	14,803
2020	137,482.16	104,555	114,664	22,819	2.36	9,669
2021	29,075.34	20,923	22,946	6,129	2.53	2,423
2022	135,872.28	89,825	98,509	37,363	2.82	13,249
2023	103,755.32	60,178	65,996	37,759	3.26	11,583
2024	72,901.04	34,774	38,136	34,765	3.84	9,053
2025	110,000.89	39,072	42,850	67,151	4.54	14,791
2026	133,994.54	29,479	32,329	101,665	5.32	19,110
2027	21,432.71	1,603	1,758	19,675	6.18	3,184
	1,047,654.06	628,074	688,798	358,856		97,865
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2019	58,753.80	46,445	51,599	7,155	2.25	3,180
2020	78,115.18	59,407	65,999	12,116	2.36	5,134
2021	64,848.27	46,665	51,843	13,005	2.53	5,140
2023	32,141.55	18,642	20,711	11,431	3.26	3,506
2024	70,345.77	33,555	37,279	33,067	3.84	8,611
2026	357,364.15	78,620	87,344	270,020	5.32	50,756
	661,568.72	283,334	314,775	346,794		76,327
	4,667,252.49	2,962,594	3,536,013	1,131,240		322,732

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 6.91

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	156,290.06	126,345	119,568	36,722	2.73	13,451
2018	1,103,644.77	841,860	796,704	306,941	2.95	104,048
2019	441,342.89	323,372	306,027	135,316	3.10	43,650
2020	2,617,403.03	1,813,860	1,716,567	900,836	3.32	271,336
2021	684,272.13	437,660	414,185	270,088	3.66	73,795
2022	1,495,702.03	853,896	808,094	687,608	4.13	166,491
2023	2,311,394.47	1,128,423	1,067,896	1,243,498	4.72	263,453
2024	3,903,000.23	1,535,440	1,453,081	2,449,919	5.40	453,689
2025	3,120,541.42	902,461	854,054	2,266,487	6.14	369,135
2026	4,065,297.36	720,777	682,116	3,383,182	6.96	486,089
2027	11,332,758.03	677,699	641,348	10,691,410	7.85	1,361,963
	31,231,646.42	9,361,793	8,859,640	22,372,007		3,607,100
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	836,406.47	676,151	721,302	115,104	2.73	42,163
2018	611,852.62	466,721	497,887	113,966	2.95	38,633
2019	1,697,793.38	1,243,973	1,327,041	370,752	3.10	119,597
2020	2,654,885.85	1,839,836	1,962,694	692,192	3.32	208,492
2021	987,525.20	631,621	673,799	313,727	3.66	85,718
2022	1,713,726.64	978,367	1,043,699	670,028	4.13	162,234
2023	1,441,996.33	703,983	750,993	691,004	4.72	146,399
2024	2,004,741.11	788,665	841,329	1,163,412	5.40	215,447
2025	1,997,974.73	577,814	616,398	1,381,576	6.14	225,012
2026	1,360,087.99	241,144	257,247	1,102,841	6.96	158,454
2027	217,546.54	13,009	13,878	203,669	7.85	25,945
	15,524,536.86	8,161,284	8,706,267	6,818,270		1,428,094
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2019	1,355,363.22	993,075	1,124,120	231,243	3.10	74,595
2020	2,003,353.34	1,388,324	1,571,526	431,827	3.32	130,068
2021	1,739,612.08	1,112,656	1,259,481	480,131	3.66	131,183
2022	1,522,755.39	869,341	984,058	538,697	4.13	130,435

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2023	592,754.09	289,383	327,570	265,184	4.72	56,183
2024	636,195.54	250,279	283,306	352,890	5.40	65,350
2025	1,524,658.17	440,931	499,116	1,025,542	6.14	167,026
2026	5,105,975.85	905,290	1,024,751	4,081,225	6.96	586,383
	14,480,667.68	6,249,279	7,073,928	7,406,740		1,341,223
	61,236,850.96	23,772,356	24,639,835	36,597,017		6,376,417

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.7 10.41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	151,470.08	104,287	125,492	25,978	3.85	6,748
2020	1,825,853.39	1,158,504	1,394,067	431,787	4.32	99,951
2022	155,830.23	76,965	92,615	63,216	5.64	11,209
2025	415,782.24	97,626	117,477	298,306	8.15	36,602
	2,548,935.94	1,437,382	1,729,650	819,286		154,510
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	452,511.82	330,605	341,149	111,363	3.50	31,818
2020	768,711.75	487,748	503,304	265,408	4.32	61,437
2021	72,402.65	41,183	42,496	29,906	4.93	6,066
2022	225,312.74	111,282	114,831	110,482	5.64	19,589
2024	435,531.67	141,766	146,287	289,244	7.25	39,896
2025	145,862.61	34,249	35,341	110,521	8.15	13,561
2026	218,968.70	30,962	31,949	187,019	9.10	20,552
2027	35,022.72	1,653	1,706	33,317	10.09	3,302
	2,354,324.66	1,179,448	1,217,065	1,137,260		196,221
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	571,135.22	393,227	426,342	144,793	3.85	37,609
2020	477,207.40	302,788	328,287	148,921	4.32	34,472
2021	159,371.81	90,651	98,285	61,087	4.93	12,391
2022	234,459.29	115,799	125,551	108,908	5.64	19,310
2023	171,839.19	70,832	76,797	95,042	6.42	14,804
2024	311,597.02	101,425	109,966	201,631	7.25	27,811
2025	273,740.09	64,274	69,687	204,053	8.15	25,037
2026	524,028.77	74,098	80,338	443,691	9.10	48,757
	2,723,378.79	1,213,094	1,315,253	1,408,126		220,191
	7,626,639.39	3,829,924	4,261,968	3,364,672		570,922

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9 7.49

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	535,638.12	391,337	465,773	69,865	3.50	19,961
2019	381,787.38	262,861	312,860	68,928	3.85	17,903
2020	414,682.49	263,116	313,163	101,519	4.32	23,500
2021	310,179.53	176,430	209,989	100,191	4.93	20,323
2022	1,307,895.60	645,970	768,840	539,055	5.64	95,577
2023	547,886.82	225,839	268,796	279,091	6.42	43,472
2025	889,618.07	208,882	248,614	641,005	8.15	78,651
	4,387,688.01	2,174,435	2,588,035	1,799,653		299,387
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	405,513.06	296,268	303,960	101,553	3.50	29,015
2019	305,429.27	210,288	215,748	89,682	3.85	23,294
2020	340,278.48	215,907	221,513	118,766	4.32	27,492
2023	813,719.90	335,415	344,123	469,597	6.42	73,146
2025	813,569.24	191,026	195,986	617,584	8.15	75,777
2026	317,534.33	44,899	46,065	271,470	9.10	29,832
2027	50,787.70	2,397	2,459	48,328	10.09	4,790
	3,046,831.98	1,296,200	1,329,853	1,716,979		263,346
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2002	64,657.75	63,345	64,658			
2005	234,486.07	222,785	234,486			
2019	301,872.38	207,839	226,732	75,140	3.85	19,517
2020	510,673.88	324,023	353,477	157,196	4.32	36,388
2023	267,890.81	110,425	120,463	147,428	6.42	22,964

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2024	1,374,619.01	447,438	488,111	886,508	7.25	122,277
2025	14,484.75	3,401	3,710	10,775	8.15	1,322
2026	856,457.41	121,103	132,112	724,346	9.10	79,598
	3,625,142.06	1,500,359	1,623,749	2,001,393		282,066
	11,059,662.05	4,970,994	5,541,637	5,518,025		844,799

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 7.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	16,490.72	12,549	15,995	496	4.87	102
2014	38,491.58	27,853	35,502	2,990	5.16	579
2016	325,609.19	220,568	281,140	44,469	5.48	8,115
2018	36,897.65	22,751	28,999	7,899	5.91	1,337
2019	26,522.13	15,309	19,513	7,009	6.23	1,125
2020	69,273.71	36,784	46,886	22,388	6.62	3,382
2021	21,143.06	10,087	12,857	8,286	7.12	1,164
2025	26,522.47	5,424	6,914	19,609	9.72	2,017
	560,950.51	351,325	447,806	113,145		17,821
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1998	5,861.50	5,435	5,617	244	2.30	106
2004	1,094.08	951	983	111	3.49	32
2010	42,780.07	33,916	35,052	7,728	4.57	1,691
2011	46,078.31	35,812	37,012	9,067	4.73	1,917
2018	75,745.86	46,705	48,270	27,476	5.91	4,649
2020	57,873.46	30,731	31,760	26,113	6.62	3,945
2021	77,037.92	36,755	37,986	39,052	7.12	5,485
2022	19,852.05	8,276	8,553	11,299	7.69	1,469
2023	69,474.53	24,358	25,174	44,301	8.34	5,312
2025	192,866.87	39,441	40,762	152,105	9.72	15,649
2026	84,536.06	10,567	10,921	73,615	10.50	7,011
2027	13,521.54	569	588	12,933	11.38	1,136
	686,722.25	273,516	282,678	404,044		48,402
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1993	1,651.82	1,590	1,652			
2000	30,976.92	28,195	30,977			
2001	5,792.76	5,216	5,750	43	2.90	15
2002	16,245.60	14,480	15,962	284	3.08	92
2003	15,284.09	13,455	14,832	452	3.30	137
2004	84,957.51	73,879	81,438	3,520	3.49	1,009

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2005	97,134.57	83,419	91,954	5,181	3.66	1,416
2006	19,722.25	16,681	18,388	1,335	3.87	345
2008	12,522.34	10,305	11,359	1,163	4.20	277
2010	8,864.62	7,028	7,747	1,118	4.57	245
2017	7,046.36	4,580	5,049	1,998	5.65	354
2019	69,224.39	39,956	44,044	25,180	6.23	4,042
2020	107,418.09	57,039	62,875	44,543	6.62	6,729
2021	239,940.91	114,476	126,189	113,752	7.12	15,976
2022	214,479.59	89,417	98,566	115,914	7.69	15,073
2024	201,759.41	56,412	62,184	139,576	9.02	15,474
2025	361,480.97	73,923	81,486	279,995	9.72	28,806
2026	202,315.77	25,289	27,876	174,439	10.50	16,613
	1,696,817.97	715,340	788,326	908,492		106,603
	2,944,490.73	1,340,181	1,518,810	1,425,681		172,826

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.2 5.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,589.99	3,773	3,773	1,817	6.50	280
2018	10,248.45	4,868	4,867	5,381	10.50	512
	15,838.44	8,641	8,640	7,198		792
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					9.1	5.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	236,121.16	230,218	234,123	1,998	0.50	1,998
2009	314,488.38	290,902	295,837	18,652	1.50	12,435
2010	162,964.81	142,594	145,013	17,952	2.50	7,181
2011	451,363.00	372,374	378,690	72,673	3.50	20,764
2012	368,654.37	285,707	290,553	78,101	4.50	17,356
2013	792,113.30	574,282	584,023	208,090	5.50	37,835
2014	476,076.46	321,352	326,803	149,273	6.50	22,965
2015	1,648,297.12	1,030,186	1,047,661	600,636	7.50	80,085
2016	1,270,294.92	730,420	742,810	527,485	8.50	62,057
2017	1,830,420.92	960,971	977,272	853,149	9.50	89,805
2018	915,728.07	434,971	442,349	473,379	10.50	45,084
2019	1,013,925.51	430,918	438,228	575,698	11.50	50,061
2020	1,214,941.27	455,603	463,331	751,610	12.50	60,129
2021	2,421,094.90	786,856	800,203	1,620,892	13.50	120,066
2022	2,950,748.68	811,456	825,221	2,125,528	14.50	146,588
2023	2,303,400.56	518,265	527,056	1,776,344	15.50	114,603
2024	1,538,342.77	269,210	273,777	1,264,566	16.50	76,640
2025	1,186,024.58	148,253	150,768	1,035,257	17.50	59,158
2026	866,467.20	64,985	66,087	800,380	18.50	43,264
2027	1,406,467.20	35,162	35,758	1,370,709	19.50	70,293
	23,367,935.18	8,894,685	9,045,564	14,322,372		1,138,367
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	194,881.81	190,010	191,894	2,988	0.50	2,988
2009	386,652.36	357,653	361,200	25,453	1.50	16,969
2010	528,508.76	462,445	467,031	61,478	2.50	24,591
2011	46,412.17	38,290	38,670	7,742	3.50	2,212
2012	106,370.79	82,437	83,254	23,116	4.50	5,137
2013	245,409.98	177,922	179,686	65,724	5.50	11,950
2014	495,061.18	334,166	337,480	157,582	6.50	24,243
2015	960,119.93	600,075	606,025	354,095	7.50	47,213
2016	523,955.99	301,275	304,262	219,694	8.50	25,846
2017	608,859.13	319,651	322,821	286,038	9.50	30,109
2018	1,012,779.35	481,070	485,840	526,939	10.50	50,185
2019	553,146.33	235,087	237,418	315,728	11.50	27,455
2020	1,269,985.14	476,244	480,966	789,019	12.50	63,122
2021	1,323,741.79	430,216	434,482	889,260	13.50	65,871

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	786,517.05	216,292	218,437	568,080	14.50	39,178
2023	1,635,510.95	367,990	371,639	1,263,872	15.50	81,540
2024	938,712.15	164,275	165,904	772,808	16.50	46,837
2025	778,594.88	97,324	98,289	680,306	17.50	38,875
2026	488,309.08	36,623	36,986	451,323	18.50	24,396
2027	488,309.08	12,208	12,329	475,980	19.50	24,409
	13,371,837.90	5,381,253	5,434,614	7,937,224		653,126
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	601,711.46	586,669	539,359	62,352	0.50	62,352
2009	555,234.09	513,592	472,175	83,059	1.50	55,373
2010	130,973.00	114,601	105,359	25,614	2.50	10,246
2011	37,493.92	30,932	28,438	9,056	3.50	2,587
2012	293,686.51	227,607	209,252	84,434	4.50	18,763
2013	299,610.27	217,217	199,700	99,910	5.50	18,165
2014	509,913.33	344,191	316,435	193,478	6.50	29,766
2015	265,009.96	165,631	152,274	112,736	7.50	15,031
2016	645,329.65	371,065	341,142	304,188	8.50	35,787
2017	190,998.54	100,274	92,188	98,811	9.50	10,401
2018	723,680.35	343,748	316,028	407,653	10.50	38,824
2019	612,456.17	260,294	239,304	373,153	11.50	32,448
2020	522,174.71	195,816	180,025	342,150	12.50	27,372
2021	1,106,649.73	359,661	330,657	775,992	13.50	57,481
2022	842,166.59	231,596	212,920	629,247	14.50	43,396
2023	351,898.78	79,177	72,792	279,107	15.50	18,007
2024	213,446.62	37,353	34,341	179,106	16.50	10,855
2025	658,104.88	82,263	75,629	582,476	17.50	33,284
2026	479,218.69	35,941	33,043	446,176	18.50	24,118
2027	479,218.70	11,980	11,014	468,205	19.50	24,011
	9,518,975.95	4,309,608	3,962,075	5,556,901		568,267
	46,258,749.03	18,585,546	18,442,252	27,816,497		2,359,760

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8 5.10

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	345	337	216	7.50	29
2016	295.77	170	166	130	8.50	15
2017	411,182.60	215,871	210,917	200,266	9.50	21,081
2018	25,747.54	12,230	11,949	13,798	10.50	1,314
	437,778.64	228,616	223,369	214,410		22,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 5.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,808	6,206	293	3.24	90
2001	27,339.91	24,185	25,841	1,499	3.42	438
2002	3,719.59	3,249	3,471	248	3.65	68
2003	30,828.76	26,614	28,436	2,393	3.84	623
2004	11,906.59	10,160	10,856	1,051	4.00	263
2005	9,418.96	7,921	8,463	956	4.21	227
2006	22,392.50	18,559	19,830	2,563	4.39	584
2007	37,931.66	30,956	33,075	4,856	4.56	1,065
2009	17,602.56	13,906	14,858	2,745	4.92	558
2013	15,373.86	11,146	11,909	3,465	5.50	630
2018	220,480.47	130,921	139,884	80,596	6.50	12,399
2019	308,929.87	170,962	182,667	126,263	6.86	18,406
2020	2,155,616.89	1,091,173	1,165,878	989,739	7.32	135,210
2021	384,329.95	174,370	186,308	198,022	7.83	25,290
2022	684,283.11	269,881	288,358	395,925	8.45	46,855
2023	216,868.00	71,827	76,744	140,124	9.09	15,415
2024	255,991.05	67,479	72,099	183,892	9.78	18,803
2025	755,399.83	145,188	155,128	600,272	10.50	57,169
	5,164,911.92	2,274,305	2,430,010	2,734,902		334,093
PNG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	58,799	68,110			
2004	167,248.57	142,713	167,249			
2007	13,369.18	10,911	12,999	370	4.56	81
2008	35,075.31	28,250	33,657	1,418	4.71	301
2009	48,114.46	38,010	45,285	2,829	4.92	575
2010	12,089.03	9,371	11,165	924	5.07	182
2016	8,023.37	5,278	6,288	1,735	5.98	290
2018	1,346,981.57	799,838	952,924	394,058	6.50	60,624
2020	1,330,094.12	673,294	802,160	527,934	7.32	72,122
2021	407,333.02	184,807	220,178	187,155	7.83	23,902
2022	764,277.51	301,431	359,124	405,154	8.45	47,947
2024	118,030.40	31,113	37,068	80,962	9.78	8,278
2025	305,022.18	58,625	69,846	235,177	10.50	22,398
	4,623,768.46	2,342,440	2,786,052	1,837,716		236,700

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2001	29,034.66	25,684	27,002	2,033	3.42	594
2003	58,019.67	50,088	52,658	5,362	3.84	1,396
2004	98,699.95	84,221	88,542	10,158	4.00	2,540
2005	80,413.99	67,628	71,097	9,316	4.21	2,213
2006	32,646.90	27,058	28,446	4,201	4.39	957
2008	69,039.30	55,604	58,457	10,583	4.71	2,247
2019	106,125.88	58,730	61,743	44,383	6.86	6,470
2020	920,993.58	466,207	490,125	430,869	7.32	58,862
2021	727,173.36	329,919	346,845	380,329	7.83	48,573
2022	603,777.04	238,130	250,347	353,430	8.45	41,826
2023	338,548.00	112,127	117,879	220,669	9.09	24,276
2024	162,408.89	42,811	45,007	117,402	9.78	12,004
2025	366,261.18	70,395	74,006	292,255	10.50	27,834
2026	416,339.73	48,837	51,342	364,997	11.29	32,329
	4,009,482.13	1,677,439	1,763,496	2,245,986		262,121
	13,798,162.51	6,294,184	6,979,558	6,818,604		832,914
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.2	6.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	67,288.99	43,738	42,642	24,647	3.50	7,042
2023	23,301.32	10,486	10,223	13,078	5.50	2,378
2024	328,750.94	115,063	112,180	216,571	6.50	33,319
2025	102,352.01	25,588	24,947	77,405	7.50	10,321
	521,693.26	194,875	189,992	331,701		53,060
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	33,841.70	28,765	21,372	12,470	1.50	8,313
2020	50,424.62	37,818	28,098	22,326	2.50	8,930
2021	75,819.30	49,283	36,617	39,202	3.50	11,201
2022	80,244.45	44,134	32,791	47,453	4.50	10,545
2023	99,558.60	44,801	33,287	66,272	5.50	12,049
2025	208,029.43	52,007	38,641	169,389	7.50	22,585
	547,918.10	256,808	190,806	357,112		73,623
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	45,131.19	33,848	30,094	15,038	2.50	6,015
2021	21,890.53	14,229	12,651	9,240	3.50	2,640
2022	73,558.62	40,457	35,969	37,589	4.50	8,353
2024	407,805.20	142,732	126,900	280,905	6.50	43,216
2025	746,140.09	186,535	165,844	580,296	7.50	77,373
	1,294,525.63	417,801	371,458	923,067		137,597
	2,364,136.99	869,484	752,256	1,611,880		264,280

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.1 11.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	68,350.42	66,072	68,350			
2014	140,132.49	126,119	140,132			
2015	39,471.49	32,893	39,471			
2016	32,235.43	24,714	32,235			
2017	165,977.94	116,185	165,978			
2018	8,884.33	5,627	8,088	796	5.50	145
2020	89,054.88	44,527	64,001	25,054	7.50	3,341
2024	3,226.50	753	1,082	2,144	11.50	186
2026	138,749.73	13,875	19,943	118,807	13.50	8,801
2027	171,796.20	5,726	8,230	163,566	14.50	11,280
	857,879.41	436,491	547,512	310,367		23,753
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	262,109.02	235,898	262,109			
2016	44,259.57	33,932	44,260			
2017	64,069.97	44,849	64,070			
2018	1,869.95	1,184	1,870			
2020	61,699.27	30,850	54,997	6,702	7.50	894
2022	43,216.83	15,846	28,249	14,968	9.50	1,576
2023	41,520.68	12,456	22,206	19,315	10.50	1,840
2024	35,482.97	8,279	14,759	20,724	11.50	1,802
2025	15,929.11	2,655	4,733	11,196	12.50	896
2026	139,058.27	13,906	24,791	114,268	13.50	8,464
2027	172,219.56	5,740	10,233	161,987	14.50	11,172
	881,435.20	405,595	532,276	349,159		26,644
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	2,414.03	2,334	2,414			
2015	4,085.64	3,405	3,965	120	2.50	48
2017	81,771.73	57,240	66,656	15,115	4.50	3,359
2018	4,477.95	2,836	3,303	1,175	5.50	214
2019	5,471.06	3,100	3,610	1,861	6.50	286

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	30,914.09	11,335	13,200	17,714	9.50	1,865
2023	42,498.56	12,750	14,847	27,651	10.50	2,633
2026	245,853.70	24,585	28,629	217,224	13.50	16,091
2027	163,152.53	5,438	6,333	156,820	14.50	10,815
	580,639.29	123,023	142,957	437,682		35,311
	2,319,953.90	965,109	1,222,745	1,097,208		85,708

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.8 3.69

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING - DENVER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 1-2069						
NET SALVAGE PERCENT.. 0						
2019	29,987,923.48	6,372,434	6,770,577	23,217,347	31.50	737,059
2020	1,918,595.10	369,905	393,016	1,525,579	31.41	48,570
2021	647,293.08	111,464	118,428	528,865	31.24	16,929
2022	2,012,444.98	304,282	323,293	1,689,152	30.87	54,718
2023	104,904.91	13,449	14,289	90,616	30.59	2,962
2024	34,006.49	3,547	3,769	30,238	30.06	1,006
2025	56,251.31	4,416	4,692	51,559	29.35	1,757
2026	354,752.12	17,950	19,071	335,681	28.17	11,916
2027	178,630.87	3,483	3,701	174,930	25.14	6,958
	35,294,802.34	7,200,930	7,650,836	27,643,966		881,875
READING DATA CENTER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2073						
NET SALVAGE PERCENT.. 0						
2023	11,744,977.98	1,427,015	1,538,771	10,206,207	32.54	313,651
2024	8,669,490.58	855,679	922,691	7,746,800	31.96	242,390
	20,414,468.56	2,282,694	2,461,462	17,953,007		556,041
KNITTING MILLS OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. 0						
2022	1,382,240.38	298,011	315,949	1,066,291	20.01	53,288
	1,382,240.38	298,011	315,949	1,066,291		53,288
	57,091,511.28	9,781,635	10,428,247	46,663,264		1,491,204
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					31.3	2.61

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	3,525,373.71	1,498,284	1,437,305	2,088,069	11.50	181,571
2020	39,198.12	14,699	14,101	25,097	12.50	2,008
2021	10,994.97	3,573	3,428	7,567	13.50	561
2022	823,953.90	226,587	217,365	606,589	14.50	41,834
2024	1,250.26	219	210	1,040	16.50	63
2025	475,773.40	59,472	57,051	418,722	17.50	23,927
2026	50,000.00	3,750	3,598	46,402	18.50	2,508
2027	50,000.00	1,250	1,199	48,801	19.50	2,503
	4,976,544.36	1,807,834	1,734,257	3,242,288		254,975

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7 5.12

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	6,905,686.94	6,215,118	6,282,056	623,631	0.50	623,631
2024	6,182,441.02	4,327,709	4,374,320	1,808,121	1.50	1,205,414
2025	4,789,195.97	2,394,598	2,420,388	2,368,808	2.50	947,523
	17,877,323.93	12,937,425	13,076,764	4,800,560		2,776,568
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					1.7	15.53

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2024						
NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,803,866	2,803,866			
	2,803,866.07	2,803,866	2,803,866			
UNITE ERP						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2034						
NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	5,865,479	5,347,641	5,348,175	7.00	764,025
	10,695,816.43	5,865,479	5,347,641	5,348,175		764,025
	13,499,682.50	8,669,345	8,151,507	5,348,175		764,025
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.0	5.66

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	3,263,096.61	3,099,942	3,017,180	245,917	0.50	245,917
2019	5,704,158.66	4,848,535	4,719,089	985,070	1.50	656,713
2020	12,128,665.41	9,096,499	8,853,641	3,275,024	2.50	1,310,010
2021	7,348,351.93	4,776,429	4,648,908	2,699,444	3.50	771,270
2022	7,986,056.82	4,392,331	4,275,065	3,710,992	4.50	824,665
2023	4,577,322.93	2,059,795	2,004,803	2,572,520	5.50	467,731
2024	3,605,416.34	1,261,896	1,228,206	2,377,210	6.50	365,725
2025	4,331,168.46	1,082,792	1,053,884	3,277,284	7.50	436,971
2026	48,214,614.33	7,232,192	7,039,106	41,175,508	8.50	4,844,177
2027	13,854,565.16	692,728	674,233	13,180,332	9.50	1,387,403
	111,013,416.65	38,543,139	37,514,115	73,499,301		11,310,582

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 10.19

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2027

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	1,957,869.42	1,501,040	1,482,676	475,193	3.50	135,769
2017	75,949,954.16	53,164,968	52,514,550	23,435,404	4.50	5,207,868
2018	171,214.09	108,435	107,108	64,106	5.50	11,656
2019	43,488,813.59	24,643,806	24,342,314	19,146,500	6.50	2,945,615
2021	7,013,315.14	3,039,080	3,001,900	4,011,415	8.50	471,931
2022	1,548,319.97	567,722	560,777	987,543	9.50	103,952
2023	2,728,425.32	818,528	808,514	1,919,911	10.50	182,849
2024	871,670.44	203,387	200,899	670,771	11.50	58,328
2025	267,380.05	44,564	44,019	223,361	12.50	17,869
2027	299,691.22	9,989	9,866	289,825	14.50	19,988
	134,296,653.40	84,101,519	83,072,623	51,224,030		9,155,825

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.6 6.82

PART IV. EXPERIENCED AND ESTIMATED NET SALVAGE

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2023 TRANSACTION YEAR				
325.10	9,986.53			
325.20	35,825.88			
328.00	1,263.20			
329.00	44,784.66			
330.00	18,208.60			
331.00	24,440.72			
332.00	308,348.25			
334.00	89,724.69			
335.00	49,603.72			
337.00	11,062.15			
367.00	13.90	411.88		411.88-
369.00		231.13		231.13-
375.00	4,361.80	1,876.12		1,876.12-
376.10	1,911,104.74	1,693,881.68		1,693,881.68-
376.20	231,008.33	633,299.14		633,299.14-
376.30	3,015,781.26	311,402.09		311,402.09-
376.50	147.85			
378.00	125,958.48	206,791.94		206,791.94-
379.00	87,005.59	85,311.85		85,311.85-
380.00	14,014,376.89	5,345,562.48		5,345,562.48-
381.00	1,365,599.25	35,495.28		35,495.28-
381.10	1,591,780.95	2,076.27		2,076.27-
382.00	147,042.47	117,423.95		117,423.95-
383.00		805.84		805.84-
384.00	73,967.50	82.38		82.38-
390.10	2,990,794.20	395.27		395.27-
392.00	363,110.57			
392.20			887,269.86	887,269.86
394.00		167.21		167.21-
397.00		11.22		11.22-
398.00		79,441.38		79,441.38-
	26,515,302.18	8,514,667.11	887,269.86	7,627,397.25-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2024 TRANSACTION YEAR				
367.00	15,789.19-	5,800.82		5,800.82-
375.00		.25		.25-
376.10	3,278,709.32	1,190,708.39		1,190,708.39-
376.20	340,704.97	682,407.68		682,407.68-
376.30	3,202,277.34	819,607.41		819,607.41-
376.50	9.47			
378.00	1,310.54	165,132.29		165,132.29-
379.00		43,038.20		43,038.20-
380.00	11,321,460.10	4,613,723.58		4,613,723.58-
381.00	1,560,893.83	48,410.73		48,410.73-
381.10		9,684.81		9,684.81-
382.00	168,066.15	65,380.33		65,380.33-
383.00		3,328,106.96		3,328,106.96-
384.00	56,498.06	281.79		281.79-
385.00		984.10		984.10-
386.10		207.86		207.86-
390.10	3,960,071.14	552,199.64		552,199.64-
391.00	28,382.78			
391.10	10,004,713.85			
391.20	1,637.58			
391.30	6,310,627.32			
392.00	22,224.80			
392.20			645,657.43	645,657.43
393.00	1,768.11			
394.00	1,697,038.69			
397.00	31,989.83	2,888.76		2,888.76-
398.00	139,478.08	74,235.76		74,235.76-
	42,112,072.77	11,602,799.36	645,657.43	10,957,141.93-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2025 TRANSACTION YEAR				
367.00		9,570.67		9,570.67-
375.00		12,062.12		12,062.12-
376.10		2,102,594.83		2,102,594.83-
376.20		899,143.51		899,143.51-
376.30		508,772.12		508,772.12-
378.00		313,280.97		313,280.97-
379.00		196,337.52		196,337.52-
380.00		5,022,669.19		5,022,669.19-
381.00		74,865.17		74,865.17-
381.10		18,782.17		18,782.17-
382.00		94,529.64		94,529.64-
383.00		1,028,703.39		1,028,703.39-
384.00		2,577.96		2,577.96-
385.00		87,207.33		87,207.33-
386.00		774.21		774.21-
386.10		1,025.40		1,025.40-
390.10		105,143.54		105,143.54-
392.20			749,272.22	749,272.22
397.00		9,703.27		9,703.27-
398.00		86,622.06		86,622.06-
		10,574,365.07	749,272.22	9,825,092.85-
2026 TRANSACTION YEAR				
375.00		7,249.59		7,249.59-
376.10		1,182,057.76		1,182,057.76-
376.30		757,434.79		757,434.79-
378.00		53,422.45		53,422.45-
380.00		7,271,309.73		7,271,309.73-
382.00		341,280.10		341,280.10-
385.00		326,137.90-		326,137.90
390.10		30,951.26		30,951.26-
392.10			4,546.90	4,546.90
392.20			86,856.48	86,856.48
392.30			7,429.97	7,429.97
392.40			10,774.47	10,774.47
392.50			2,868.56	2,868.56
		9,317,567.78	112,476.38	9,205,091.40-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2027 TRANSACTION YEAR				
376.10		1,347,246.70		1,347,246.70-
376.30		871,163.11		871,163.11-
378.00		73,778.57		73,778.57-
380.00		8,658,033.43		8,658,033.43-
382.00		396,838.11		396,838.11-
385.00		402,566.89-		402,566.89
390.10		71,697.00		71,697.00-
392.10			214.33	214.33
392.20			115,507.36	115,507.36
392.30			350.23	350.23
392.40			507.88	507.88
392.50			135.22	135.22
		11,016,190.03	116,715.02	10,899,475.01-
TOTAL	68,627,374.95	51,025,589.35	2,511,390.91	48,514,198.44-

BOOK VII

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C
(FUTURE)
2026 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI Gas Exhibit C (Future)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2026

Prepared by:

GANNETT FLEMING VALUATION

AND RATE CONSULTANTS LLC

UGI UTILITIES, INC. - GAS DIVISION

Docket No. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT SEPTEMBER 30, 2026

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming Valuation and Rate Consultants, LLC
(a GFT Company)

300 Sterling Parkway, Suite 200
Mechanicsburg, PA 17050
717.763.7211

January 14, 2026

Jessica R. Rogers
Vice President – Rates and Regulatory Affairs
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant in service. The results of our study at September 30, 2026 are presented in the attached report labelled as UGI Gas Exhibit C (Future).

The results of our study at September 30, 2025 are presented in our report titled "Depreciation Study- Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2025". This report is identified for purposes of this filing as UGI Gas Exhibit C (Historic). The results of our study at September 30, 2027 are presented in our report titled "Depreciation Study- Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2027". This report is identified for purposes of this filing as UGI Gas Exhibit C (Fully Projected Future). The same methods, procedures and estimates are used in all three exhibits and test years.

The attached report sets forth a description of the methods and procedures upon which the studies were based, the estimates of survivor curves and the calculated annual depreciation rates at September 30, 2026.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

085304.100

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PART I. INTRODUCTION

UGI UTILITIES, INC. - GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted for UGI Utilities, Inc. - Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2026.

The depreciation accrual rates and amounts presented herein are based on estimated survivor curves and on methods and procedures set forth in previous orders approved by the Pennsylvania Public Utility Commission. The estimated survivor curves presented herein were based on the results of a service life study incorporating statistical analyses of data through 2022 for the consolidated UGI gas company. The consolidated gas company includes the former UGI Penn Natural Gas Company (UGI PNG, now UGI North), UGI Central Penn Gas Company (UGI CPG, now UGI Central) and UGI Utilities, Inc. – Gas Division (UGI Gas, now UGI South).

BASIS OF STUDY

Depreciation and Amortization

Depreciation, as defined in the Uniform System of Accounts, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action

of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. These subjects are discussed in the sections which follow.
For most plant accounts, depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group (ELG) procedure for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property. For certain general plant accounts, the amortization amounts, annual and accrued, were based on the age of the vintage and the selected amortization period.

Survivor curves were used to reflect the expected dispersion of retirements, thus providing a consistent method of estimating service lives and depreciation for mass property. Iowa type curves were used to depict the estimated survivor curves. For life span groups, the estimate of life characteristics is consistent because the calculated

lives of the units within a group are obtained by employing a single probable retirement date for the entire group.

Service Life Estimates

The method of estimating service life consisted of compiling the service life history of the plant accounts, subaccounts or depreciable groups, reducing this history to trends through the use of acceptable actuarial techniques, and forecasting the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The Company's service life estimates used in the depreciation calculation incorporated historical data compiled through 2022 from the property records of the Company. Such data included plant additions, retirements, transfers and other activity. Generally, retirement data for the years 1951 through 2022 were used in the actuarial life table computations which were the primary statistical support of the service life estimates.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through field trips conducted during the course of the service life study. Discussions with operating and management personnel also provided information regarding plans for the future which was incorporated in the interpretation and extrapolation of the statistical analyses.

AMORTIZATION OF NET SALVAGE

Inasmuch as this report relates primarily to Pennsylvania rate regulation practices, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced and estimated net salvage recorded October 1, 2021 through September 30, 2026 over a five-year period.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below, and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

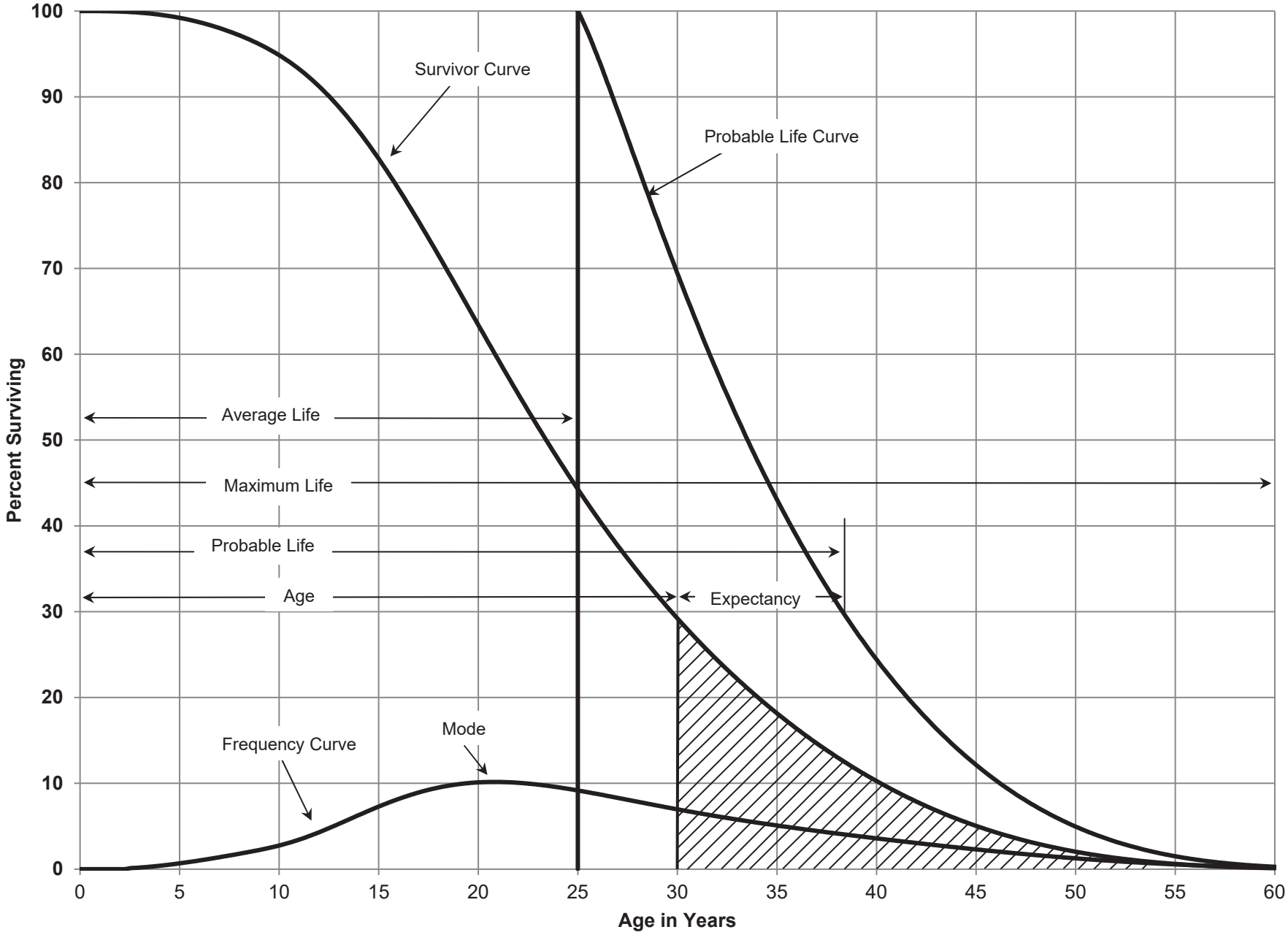


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

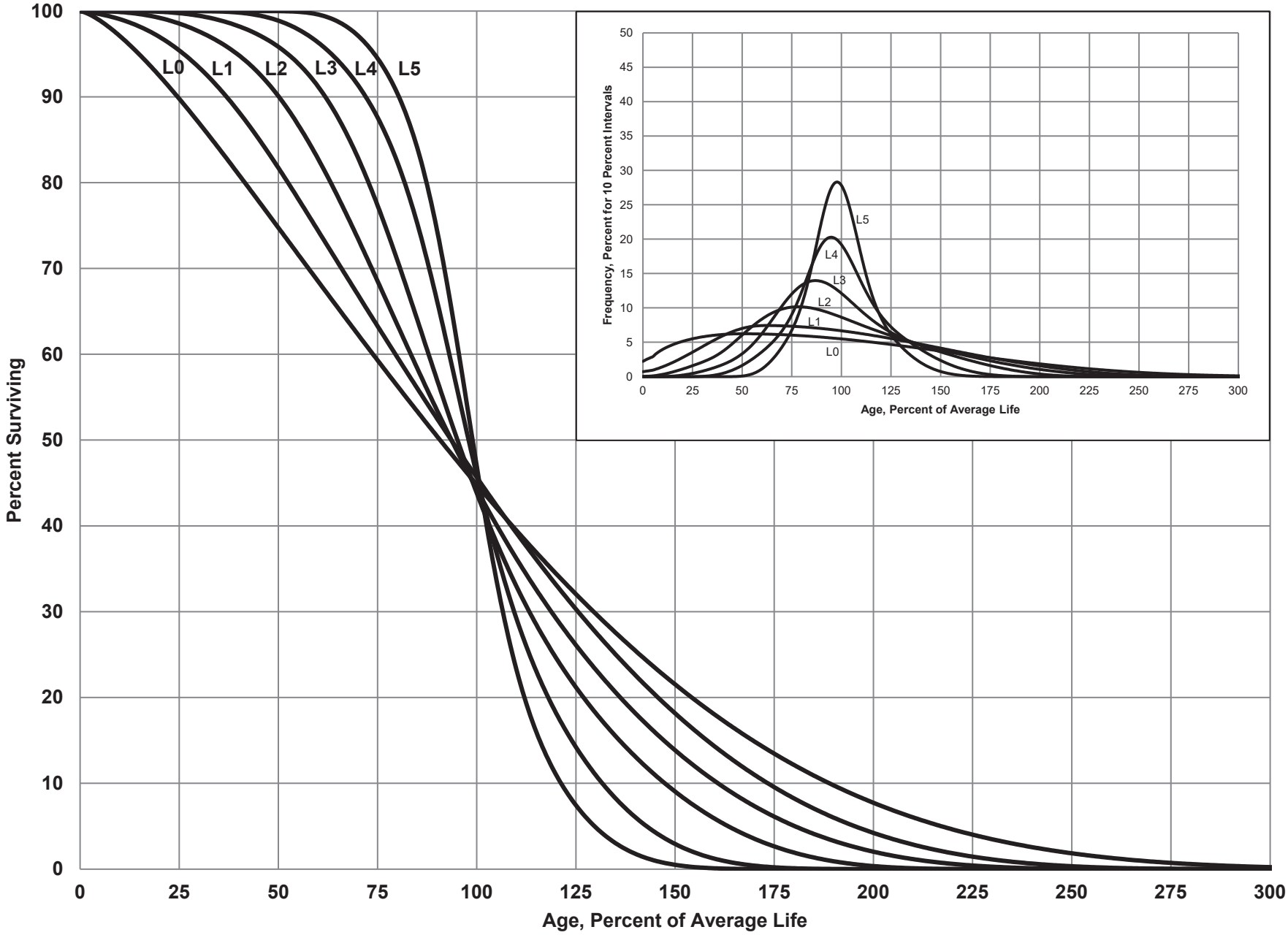


FIGURE 2.. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

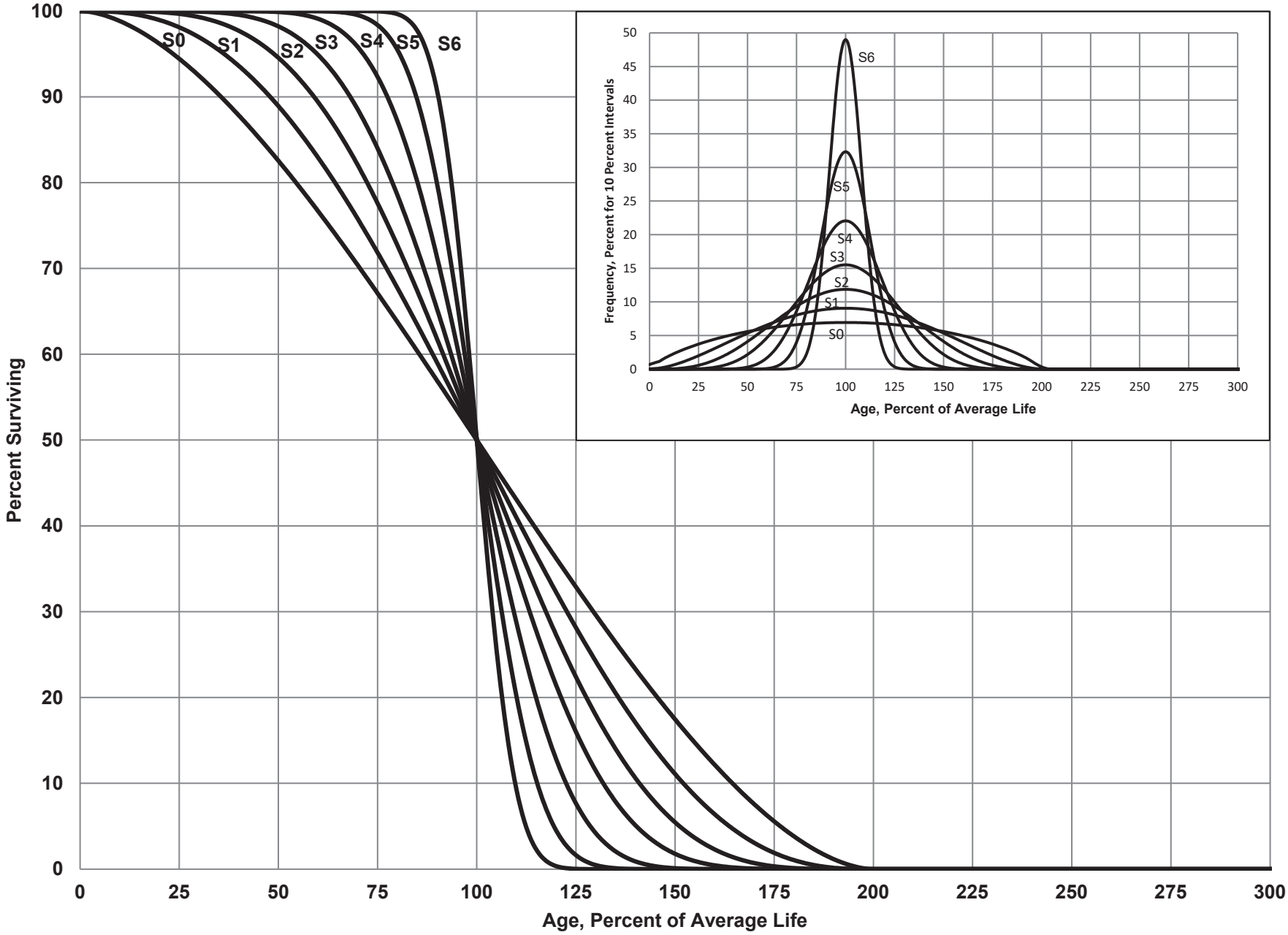


FIGURE 3.. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

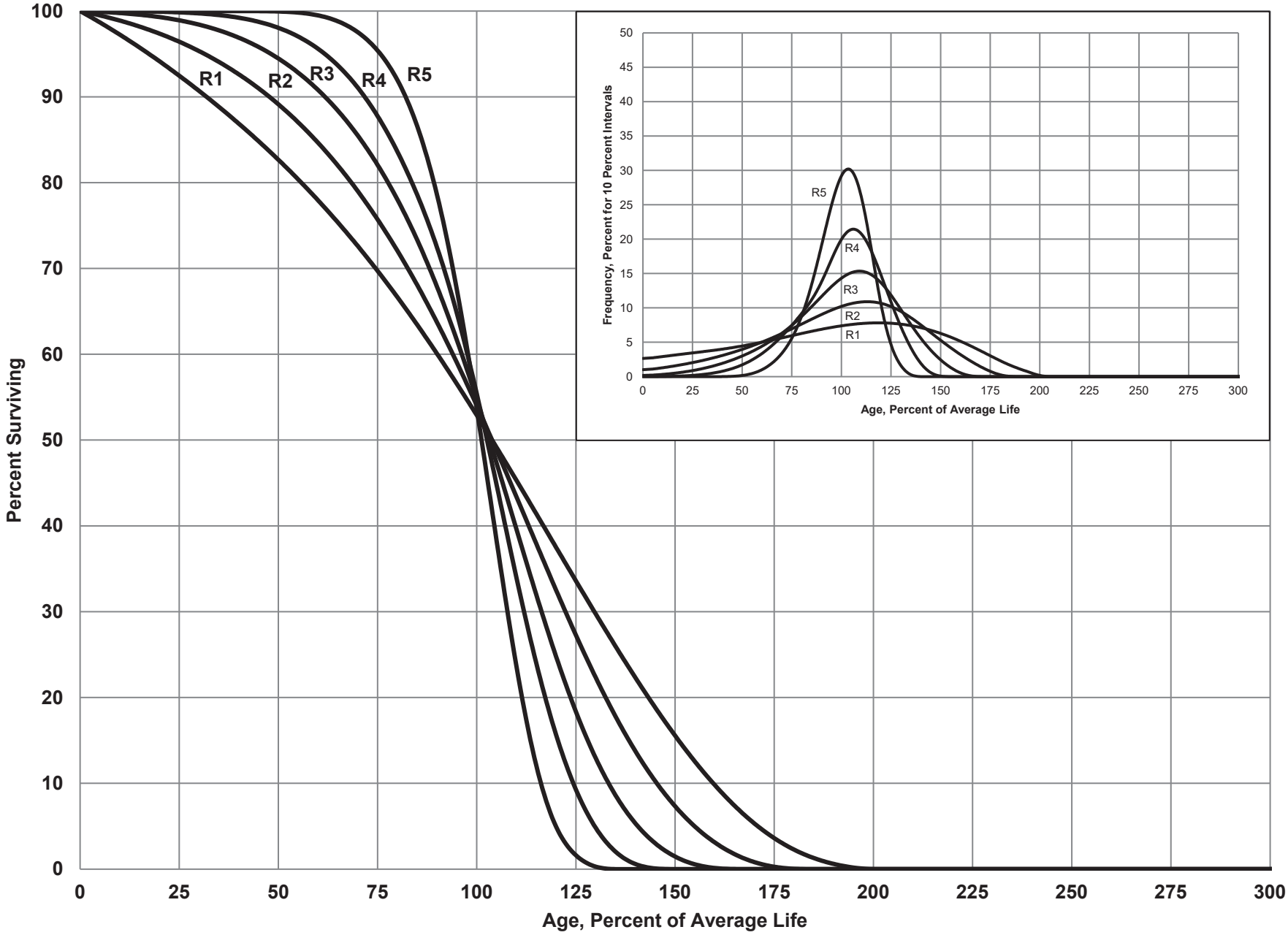


FIGURE 4.. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

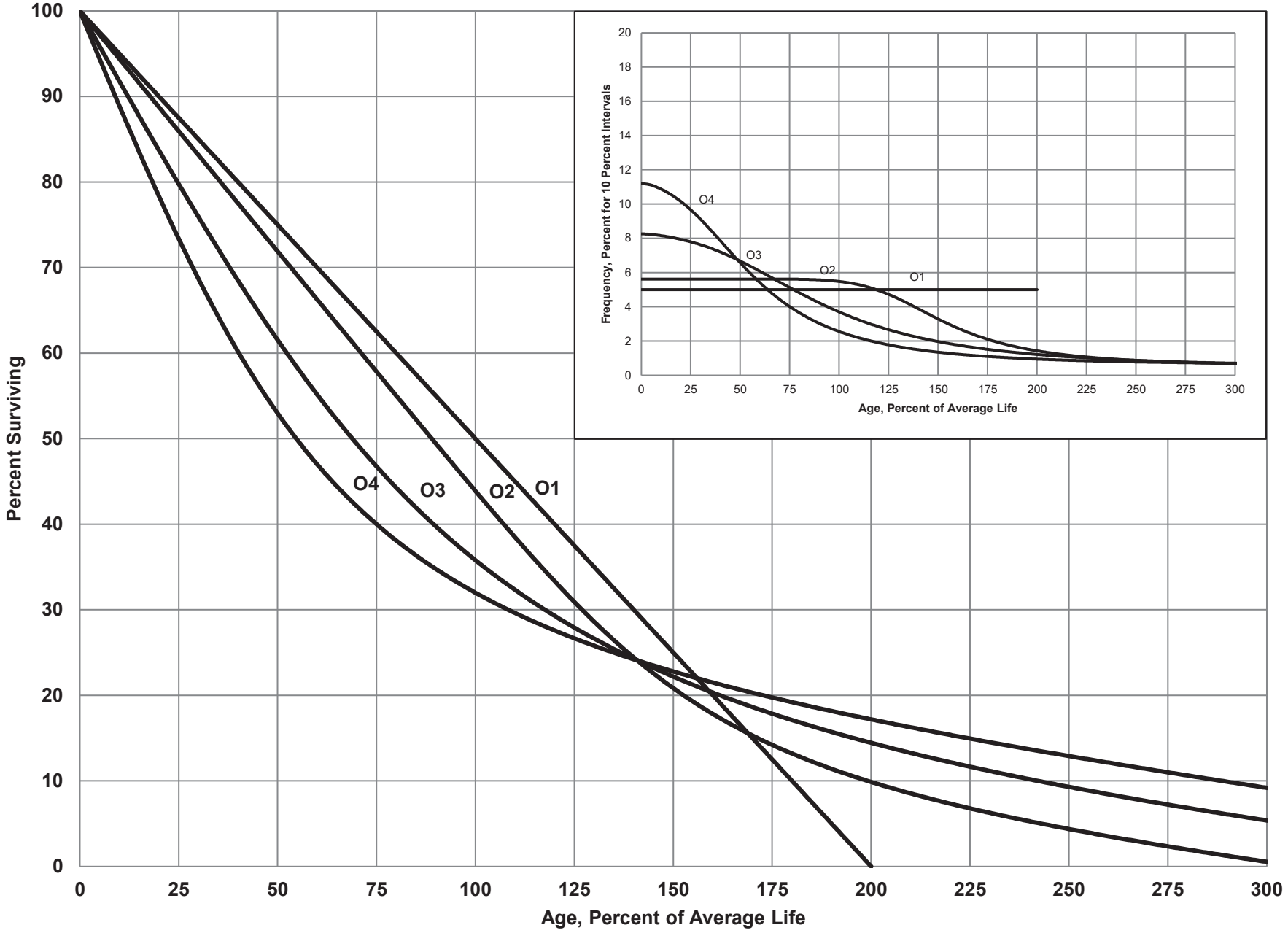


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.
[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2016-2025 for which there were placements during the years 2011-2025. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2010 were retired in 2016. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2016 retirements of 2011 installations and ending with the 2025 retirements of the 2020 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2016-2025
SUMMARIZED BY AGE INTERVAL

Experience Band 2016-2025 Placement Band 2011-2025

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2011	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2012	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2013	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2014	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2015	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2016	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2017		5	11	12	13	14	15	16	18	20	113	7½-8½
2018			6	12	13	15	16	17	19	19	124	6½-7½
2019				6	13	15	16	17	19	19	131	5½-6½
2020					7	14	16	17	19	20	143	4½-5½
2021						8	18	20	22	23	146	3½-4½
2022							9	20	22	25	150	2½-3½
2023								11	23	25	151	1½-2½
2024									11	24	153	½-1½
2025										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2015-2024
SUMMARIZED BY AGE INTERVAL

Experience Band 2016-2025 Placement Band 2011-2025

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2011	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2012	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2013	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2014	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2015	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2016	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2017		-	-	-	-	-	-	-	-	-	6	7½-8½
2018			-	-	-	-	-	-	-	-	-	6½-7½
2019				-	-	-	-	(12)[b]	-	-	-	5½-6½
2020					-	-	-	-	22[a]	-	-	4½-5½
2021						-	-	(19)[b]	-	-	10	3½-4½
2022							-	-	-	-	-	2½-3½
2023								-	-	(102)[c]	(121)	1½-2½
2024									-	-	-	½-1½
2025											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year

[b] Transfer Affecting Exposures at End of Year

[c] Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2016 through 2025 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2021 are calculated in the following manner:

Exposures at age 0 = amount of addition	= $750,000
Exposures at age ½ = $750,000 - $ 8,000	= $742,000
Exposures at age 1½ = $742,000 - $18,000	= $724,000
Exposures at age 2½ = $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½ = $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2016-2025
SUMMARIZED BY AGE INTERVAL

Experience Band 2016-2025

Placement Band 2011-2025

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2011	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2012	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2013	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2014	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2015	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2016	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2017		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2018			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2019				580[a]	574	561	546	530	501	482	3,057	5½-6½
2020					660[a]	653	639	623	628	609	3,789	4½-5½
2021						750[a]	742	724	685	663	4,332	3½-4½
2022							850[a]	841	821	799	4,955	2½-3½
2023								960[a]	949	926	5,719	1½-2½
2024									1,080[a]	1,069	6,579	½-1½
2025										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2016-2025, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2016-2025 Placement Band 2011-2025

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

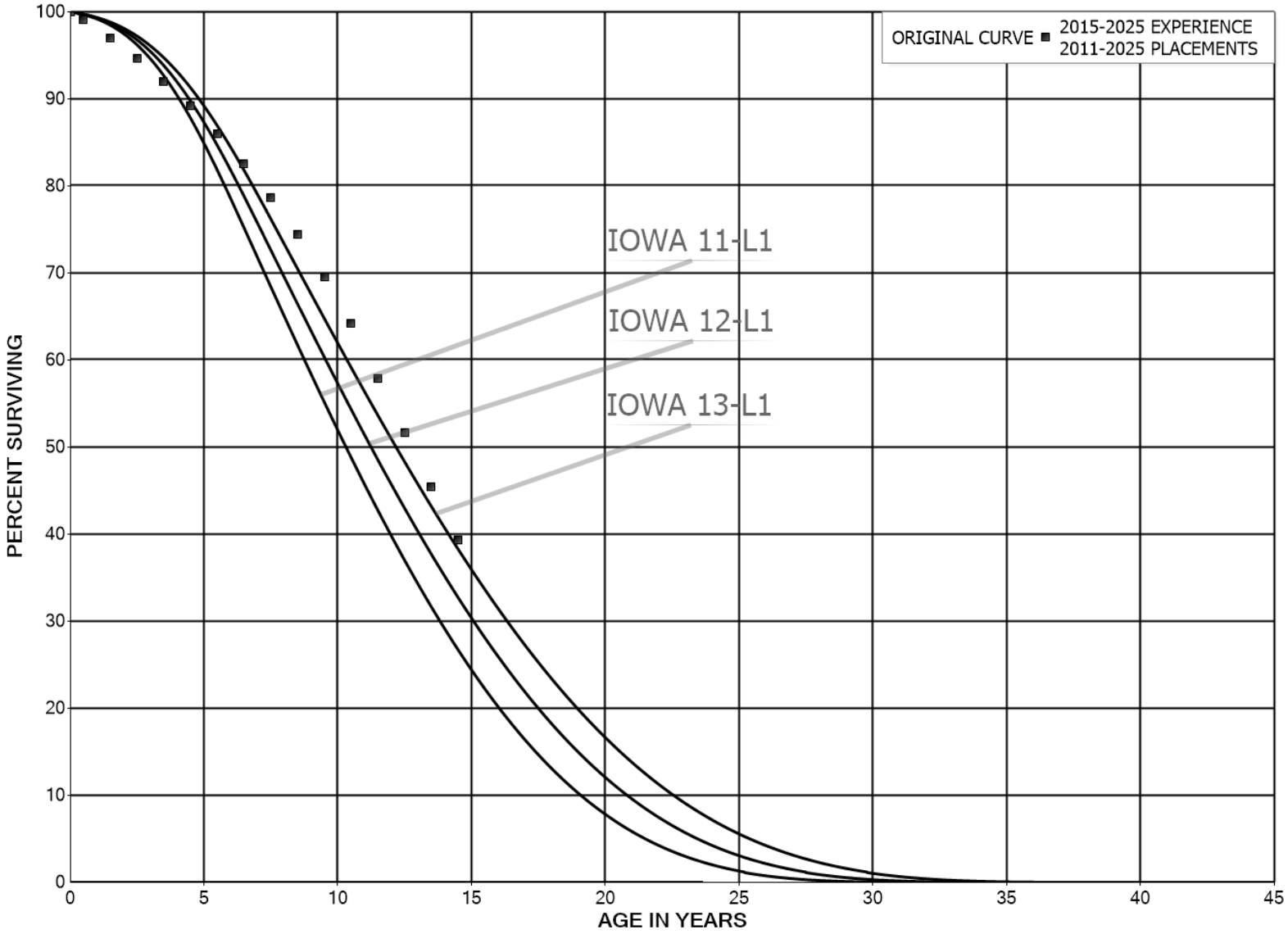


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

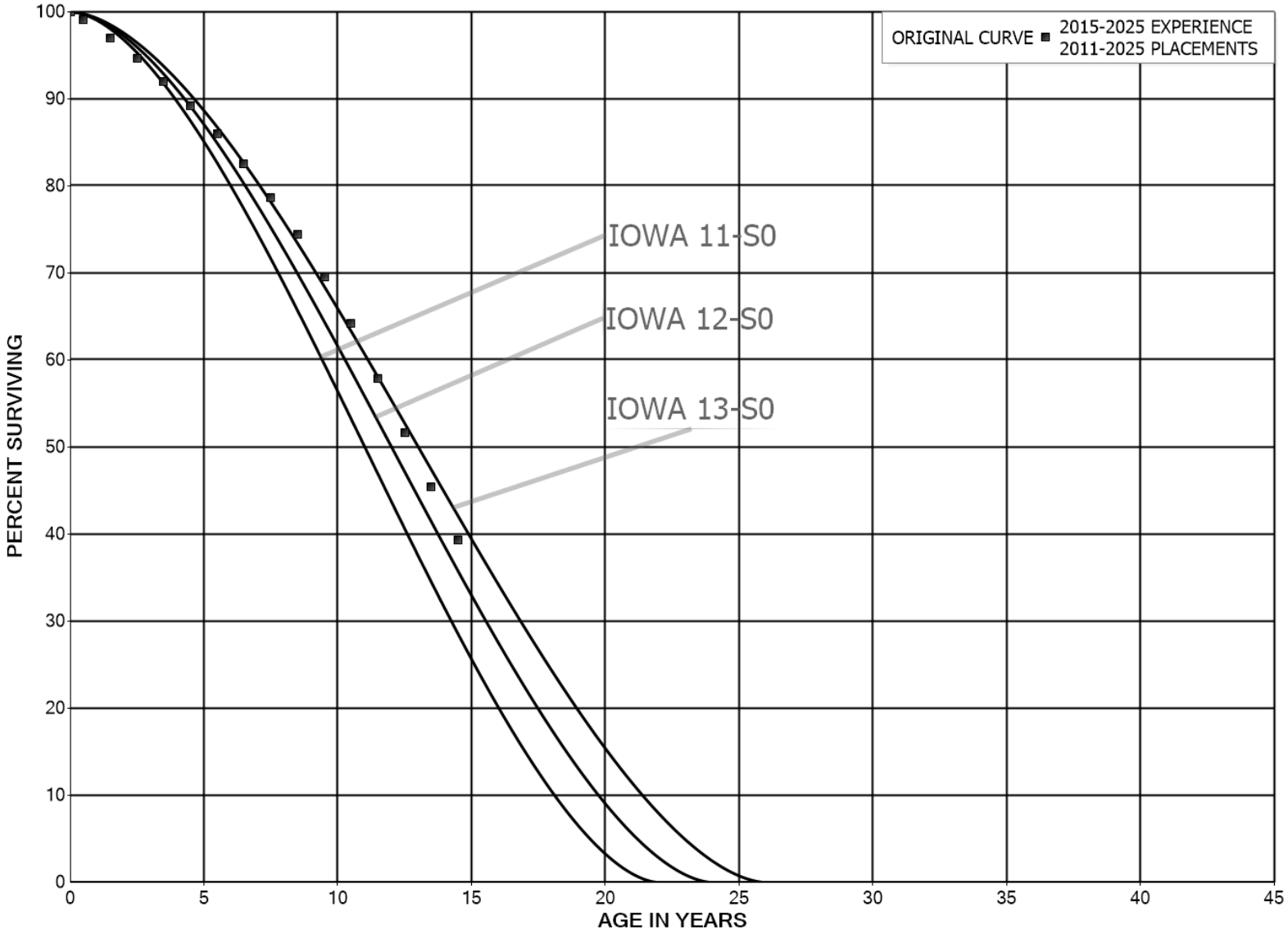


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

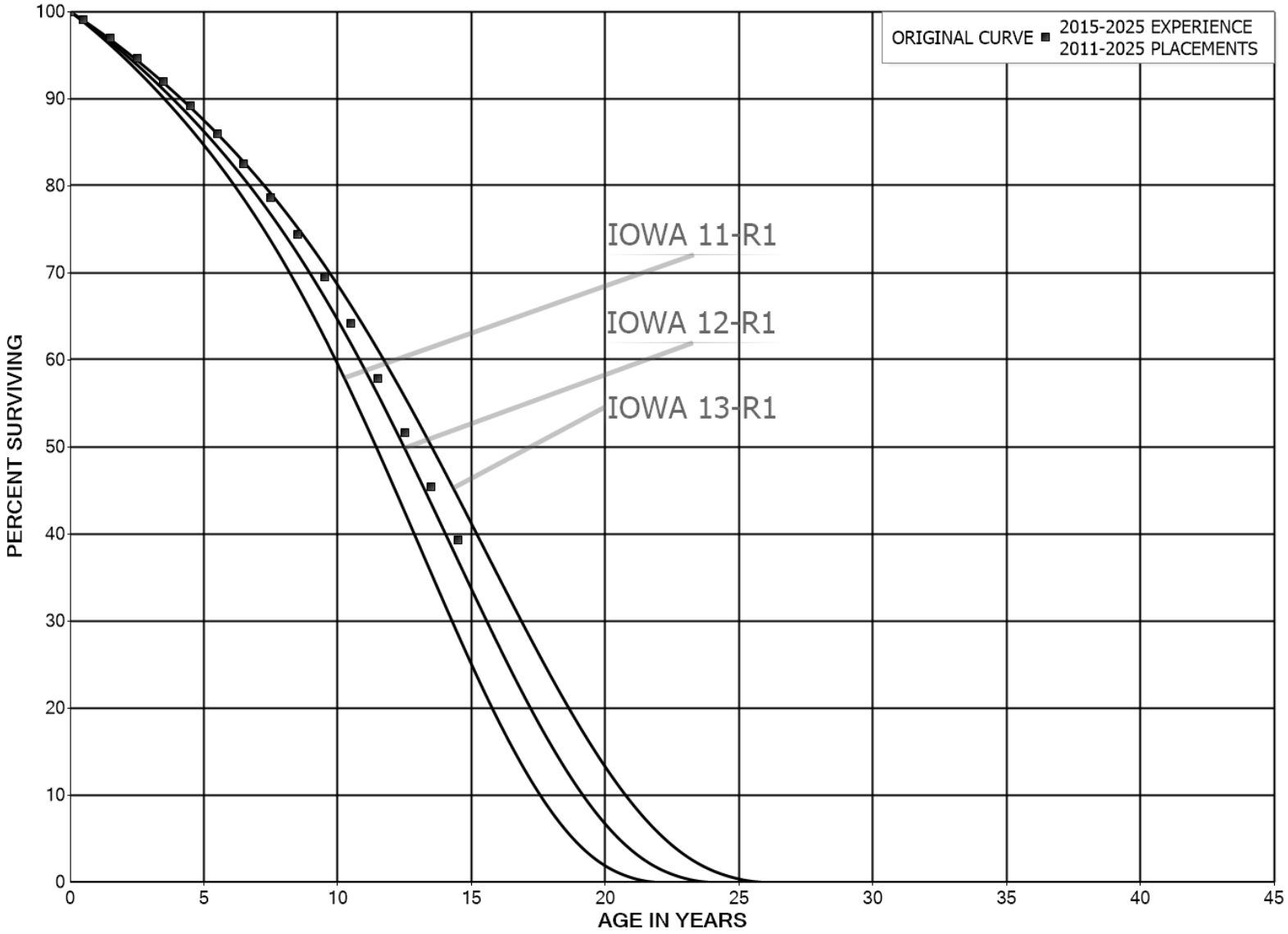
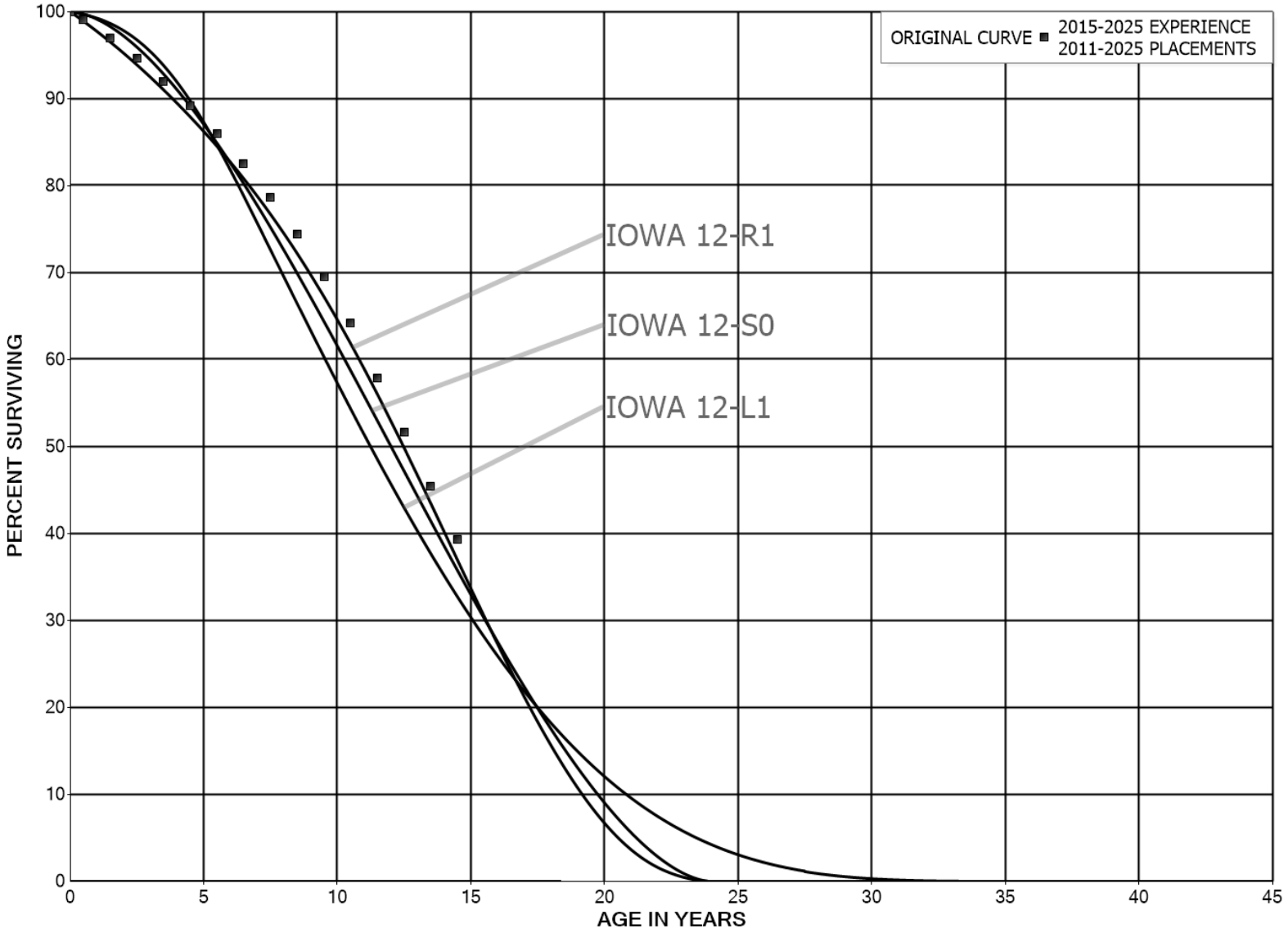


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

Field Trips

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted periodically. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

During the extensive period of years our firm has been conducting depreciation studies for the Company, the field trips have resulted in numerous reviews of the Company's operating areas. The following is a list of the locations visited during the most recent trips:

January 13, 2023

UGI Utilities, Inc. - Headquarters Office - Denver PA
Main Replacement Project on Wyomissing Avenue, Reading, PA
Museum Road District Regulating Station
Temple City Gate Station
UGI – Gas Training Center

August 16, 2018

Lancaster Service Center
Main Replacement Project on Conestoga St., Lancaster, PA
Main Replacement Project on W. Frederick St., Lancaster, PA
Fruitville City Gate Station
Lititz Metering Station
Lebanon Service Center
Lebanon District Regulating Station
Ono City Gate Station
Bern Church Meter Station
Leesport City Gate Station
Temple City Gate Station
Reading (Morgantown Road) Service Center

August 15, 2018

Stroudsburg Operations Center
Stroudsburg Measuring Station
Delaware Water Gap M&R Station
Bangor City Gate Station
Mount Bethel Metering Station
Main Replacement Project on Main Street, Easton, PA
Hellertown City Gate Station
Bethlehem (a.k.a., Lehigh Valley) Service Center

February 3, 2017

Reading Service Center
Reading Plant and Training Center, 4th St & Canal St.
Gas Control Center – Temple
Temple City Gate Station
Bethlehem (a.k.a., Lehigh Valley) Service Center
Route 512 Regulating Station (Temporary), S of Bath, PA
Locust Road Regulating Station
Hellertown City Gate Station
Bethlehem District Regulating Station at Bethlehem Plant

January 25, 2017

Lancaster Service Center
Lancaster District Regulating Station
West Lancaster City Gate Station
Marietta City Gate Station
Middletown (a.k.a., Stoneridge) Service Center
Main replacement, N 17th St & North St, Harrisburg, PA
Grantville City Gate Station
Lebanon City Gate Station

January 29, 2016

Empire Yard – Office and Service Center
Empire Yard District Regulating Station
Wyoming Avenue City Gate Station
Saylor Avenue City Gate Station
Archibald Service Center
Honesdale Service Center
Honesdale City Gate Station
Honesdale District Regulating Station
Watts Hill District Regulating Station

January 23, 2014
Mansfield/Wellsboro Operations Center
Port Allegheny Operations Center
Reed Run Take Station

December 20, 2011
Middletown (a.k.a., Stoneridge) Service Center
Marietta City Gate Station
Columbia City Gate Station
West Lancaster City Gate Station

December 14, 2011, cont.
Manheim District Regulating Station
Fruitville City Gate Station
Lancaster Service Center

December 14, 2011
Hazleton Service Center
West Hazleton District Regulating Station
Harleigh City Gate Station
Humboldt District Regulating Station

December 13, 2011
Lehigh Valley Service Center
4th and Emery District Regulating Station
Hellertown City Gate Station
Bethlehem District Regulating Station
Rosedale City Gate Station
Boyertown City Gate Station
Coventry City Gate Station
Morgantown Service Center
Central Gas Control (CGC)

December 7, 2010
Lewistown Operations Center
Lewistown City Gate Station
Belleville City Gate Station
Huntingdon Service Center
Huntington City Gate Station
Shippensburg Operations Center
Shippensburg City Gate Station

December 6, 2010

Stroudsburg Operations Center
Main Replacement Project, Smith St., East Stroudsburg
Smith St. District Regulator Station
Bangor City Gate Station
Wind Gap City Gate Station
East Stroudsburg City Gate Station
Delaware Water Gap City Gate Station
Palmerton City Gate Station
Palmerton District Regulating Station
Lehighton Operations Center
Frackville Operations Center
Mt. Laurel District Regulator Station
16th and Battery Street Regulator Station

June 7, 2007

Lehigh Valley Service Center
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bally City Gate Station
Temple City Gate Station
Reading Service Center
Morgantown City Gate Station

May 15, 2007

Locust Point City Gate Station
Dauphin City Gate Regulator Station
Hershey City Gate Regulator Station
West Lancaster City Gate Station
Harrisburg Service Center and Warehouse
Lancaster Service Center
Morgantown City Gate Station

June 6, 2002

Lehigh Valley Service Center
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bally City Gate Station
Temple City Gate Station
Reading Service Center
Morgantown City Gate Station

May 13, 2002
Hershey City Gate Station
Lebanon City Gate Station
Lebanon Service Center
Lebanon District Regulating Station
Manheim District Regulating Station
West Lancaster City Gate Station
Lancaster Service Center

May 7, 2002
Harrisburg Service Center
CNG Refueling Station at Arnold Fuel Oil
October 10, 1996
Harrisburg Service Building
Steelton LPG Plant
Marietta City Gate Station
Columbia City Gate Regulator Station
Lancaster Service Center
Lebanon Service Center

October 9, 1996
Reading Service Center
Reading LPG Plant
Temple LNG Plant and Central Gas Control

October 8, 1996
Lehigh Valley Service Center
Allentown Garage and Shop
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bethlehem LPG Plant
Didier Plant

Judgment

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during the field trips and other conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

The current consolidated gas company service life study is based on data through 2022. For a majority of the mass plant accounts and subaccounts for which survivor

curves were estimated, the statistical analyses resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the following accounts:

375.00 Structures and Improvements
376.00 Mains - Primarily Steel
376.00 Mains - Cast Iron
378.00 Measuring and Regulating Station Equipment -General
379.00 Measuring and Regulating Station Equipment -City Gate
380.00 Services
381.00 Meters
385.00 Industrial Measuring and Regulating Station Equipment
387.00 Other Equipment
390.00 Structures and Improvements
396.00 Power Operated Equipment

Account 380.00, Services, is one of the largest depreciable groups and is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged retirement and other plant accounting data were compiled for the years 1954 through 2022. These data were coded in the course of the Company's normal recordkeeping according to plant account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The data were analyzed by the retirement rate method of life analysis. The survivor curve chart for the account is presented on page VI-52 and the life table for the experience and placement band 1971-2022 plotted on the chart immediately follows it.

The survivor curve estimate for this account is the Iowa 45-R2. The service line typically consists of a length of steel or plastic pipe. Steel was predominantly used until the mid-1960's, after which copper and plastic inserts became more predominant. Direct

buried plastic pipe began to displace steel and the inserts in the 1980's. Currently, the investment in plastic services represents over 90 percent of the total account balance.

During the 1970's, the rates of service line retirements increased causing the service life to decrease. More recent retirement history indicates a decrease in the retirement levels expressed as a percent of the beginning plant balance. Discussions with operating and management personnel disclosed several reasons for the historical changes. Prior to 1970, the retirement of inactive services often was delayed due to operating practices in effect at that time. The effect of urban renewal in the Company's service area during the 1970's caused substantially greater retirements at earlier ages, but this cause of retirement has not been as important in the more recent past. Services are often replaced in connection with a main replacement project since it is economic to do so even if the services are in reasonably good condition and not at the end of their physical life. The company during the past five years has significantly increased the miles of cast iron and bare steel main that are replaced annually. Based on the company's most recent plan as set forth in the Long-Term Infrastructure Improvement Plan (LTIIP), the accelerated replacement of cast iron mains will occur over a 15-year period ending in 2027. The accelerated replacement of bare steel mains will occur over a 30-year period ending in 2041. For steel services, the principal cause of retirement continues to be deterioration and the impact of the cast iron and bare steel main replacement program as steel service lines will be replaced in connection with the cast iron and bare steel main replacement. Steel services also will be retired when the company moves meters located indoors to outside the customer's home. The company plans to move all indoor meters, not located in a historic district, to the outside within the next 15 years. This program will

also cause increased meter and meter set retirements in other related accounts such as Accounts 381.00-384.00.

The 45-R2 survivor curve estimated for Account 380.00, Services, also is estimated for Accounts 382.00, Meter Installations; 383.00, House Regulators; 384.00, House Regulator Installations; and 386.00, Other Property on Customers' Premises. The use of the estimate developed for Account 380.00, Services, for other property on customers' premises is based on the similar nature of the facilities in these groups. The use of the services estimate for the remaining accounts is based on management's intent to retire these facilities concurrently with the future retirements of service lines.

The third largest depreciable group is Account 376.10, Mains - Primarily Steel. The survivor curve estimate for this account is the Iowa 75-R2.5. In recent years, the rates of retirements of mains have been redistributed, with lesser retirement ratios during earlier age intervals and greater ratios during older age intervals after age 35. This has resulted in a somewhat different indication of the survivor curve during the recent past and for the future. Discussions with operating and management personnel indicated that corrosion control programs, including the use of plastic for smaller size mains, is the most probable cause of fewer early retirements. In addition, highway and urban renewal projects have caused relatively few retirements in the Company's service area in recent years. Increased rates of retirement at older ages are anticipated in conjunction with leak detection programs and street improvements. That is, older mains with a history of leaks will be replaced as municipalities perform street improvements in order to avoid the high cost of repair or replacement when repaving is required. In addition, the company typically will replace service lines in connection with the main replacement. As previously

mentioned, the company has in the past five years or so significantly accelerated the rate at which bare steel mains are being replaced. Bare steel and cast iron mains were primarily installed up through 1960. The company has plans to replace all bare steel mains by 2041.

Typical service lives for mains of used by other gas companies range from 55 to 80 years. The Iowa 75-R2.5 survivor curve is within the range and is a reasonable interpretation of the significant portion of the stub survivor curve through age 70 and reflects the outlook of management.

The interim survivor curve estimate for Account 376.20, Mains – Cast Iron is the Iowa 65-R1. The 65-R1 survivor curve was based on the results of the life analysis for the experience band 1960-2022. The 65-year average service life estimate is consistent with management's expectations and estimates used by other gas companies. An estimated probable retirement date, or truncation date, was used for this account as well. The estimated probable retirement date (i.e., September 30, 2027) coincides with the date the company plans to complete its replacement of cast iron mains.

Similar studies were performed for the remaining significant mass plant accounts. The results of the statistical analyses are presented in account sequence in this report, beginning on page VI-2. The major structures included in Account 390.10, Structures and Improvements were separated from the smaller structures for purposes of the study. The major structures group consists of twelve structures or office complexes of significant size and of a nature that the life span procedure is appropriate. The life spans assigned to the major structures were typically 45 to 75 years from the date of major installation and varied within this range based on individual circumstances such as size, condition, type

of construction, location, and management's plans. Continued use is planned for most of the major structures, although the company has plans to build a new Reading Service Center and vacate the existing Reading Service Center within 3 years or so. The Bethlehem Service Center has undergone a recent modernization and refurbishment and as a result its probable retirement date has been extended accordingly.

The Iowa 90-R1.5 interim survivor curve was judged appropriate for the major structures based on the 1960-2022 interim retirement experience, our observations of the buildings, consideration of the facilities which will be retired during the estimated life spans, and a review of the interim survivor curves derived for similar structures of other gas companies.

Generally, the survivor curve estimates for the remainder of the accounts, which comprise a minor portion of the total depreciable original cost, were based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data, and a general knowledge of the service lives for similar equipment in other gas companies.

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally, the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. This procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accrual rates as of September 30, 2026, the estimated book depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the vintages calculated by the average service life procedure and for the vintages calculated by the equal life group procedure follow. The detailed calculations are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future whole life depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life\ Expectancy}{Average\ Service\ Life}.$$

Equal Life Group Procedure

In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life is derived by compositing the individual equal life group remaining lives in accordance with the following equation:

$$\text{Composite Remaining Life} = \frac{(\frac{\text{Book Cost}}{\text{Life}} \times \text{Remaining Life})}{\frac{\text{Book Cost}}{\text{Life}}}$$

The book costs and lives of the several equal life groups which are summed in the foregoing equation are defined by the estimated future survivor curve.

Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining LIfe} = \frac{\sum \text{Whole Life Future Accruals}}{\sum \text{Whole Life Annual Accruals}}$$

or

$$\text{Composite Remaining Life} = \frac{\sum \text{Book Cost - Calc. Reserve}}{\sum \text{Whole Life Annual Accrual}}.$$

The annual accrual rate for each account is equal to the sum of the remaining life annual accruals for all vintages divided by the account's total original cost. The account's "composite remaining life" is calculated by dividing the sum of the future book accruals for all vintages by the sum of the remaining life annual accruals for all vintages.

The calculated accrued depreciation in the equal life group procedure also represents that portion of depreciable cost which will not be allocated to expense through

future accruals. However, the calculation is based at the equal life group level rather than the vintage group level and does not require the use of averages. The equal life group accrued depreciation ratio is calculated as follows:

$$Ratio = \frac{Remaining\ Life}{Average\ Service\ Life}.$$

Inasmuch as service life minus remaining life equals age, when averages are not employed, the foregoing equation reduces to:

$$Ratio = \frac{Age}{Service\ Life}.$$

The table on the following page illustrates the procedure for calculating straight line equal life group accrued depreciation, using an Iowa 10-L2.5 survivor curve and a September 30, 2026 calculation date.

In the table, each equal life group is defined by the age interval shown in columns 1 and 2, which identify the ages at which the first and last retirement of each group occur. The group's designated life, shown in column 3, is the midpoint of the interval. In the calculation, the equal life groups of each vintage are arranged such that the midpoint of each one-year age interval coincides with the calculation date, e.g., September 30, in this case. This enables the calculation of annual accruals which are centered on, or as of, the same date as the calculation of accrued depreciation.

The retirement during each age interval, shown in column 4, is the size of each equal life group. It is derived from the Iowa 10-L2.5 survivor curve and is the difference between the percents surviving (not shown) at the beginning and end of the age interval.

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE

INPUT PARAMETERS:
CALCULATION DATE.. 9-30-2026
SURVIVOR CURVE.... 10-L2.5

AGE INTERVAL BEG (1)	END (2)	LIFE (3)	RETIREMENTS DURING INTERVAL (4)	GROUP ANNUAL ACCRUAL (5)=(4)/(3)	YEAR INST (6)	SUMMATION OF ANNUAL ACCRUALS (7)	AVERAGE PERCENT SURVIVING (8)	ANNUAL FACTOR (9)	ACCRUED FACTOR (10)
0.000	1.000	0.500	0.05547	0.05547000000	2025	11.97110572523	99.985092	0.1197	0.0599
1.000	2.000	1.500	0.37986	0.25324000000	2024	11.78901572523	99.754600	0.1182	0.1773
2.000	3.000	2.500	1.03309	0.41323600000	2023	11.45577772523	99.048125	0.1157	0.2893
3.000	4.000	3.500	1.98796	0.56798857143	2022	10.96516543951	97.537600	0.1124	0.3934
4.000	5.000	4.500	3.59099	0.79799777778	2021	10.28217226491	94.748125	0.1085	0.4883
5.000	6.000	5.500	5.95921	1.08349272727	2020	9.34142701238	89.973025	0.1038	0.5709
6.000	7.000	6.500	8.74568	1.34548923077	2019	8.12693603336	82.620580	0.0984	0.6396
7.000	8.000	7.500	11.07393	1.47652400000	2018	6.71592941798	72.710775	0.0924	0.6930
8.000	9.000	8.500	11.94865	1.40572352941	2017	5.27480565327	61.199485	0.0862	0.7327
9.000	10.000	9.500	11.17963	1.17680315789	2016	3.98354230962	49.635345	0.0803	0.7629
10.000	11.000	10.500	9.46724	0.90164190476	2015	2.94431977830	39.311910	0.0749	0.7865
11.000	12.000	11.500	7.66323	0.66636782609	2014	2.16031491287	30.746675	0.0703	0.8085
12.000	13.000	12.500	6.19891	0.49591280000	2013	1.57917459983	23.815605	0.0663	0.8288
13.000	14.000	13.500	5.08620	0.37675555556	2012	1.14284042205	18.173050	0.0629	0.8492
14.000	15.000	14.500	4.18121	0.28835931034	2011	0.81028298910	13.539345	0.0598	0.8671
15.000	16.000	15.500	3.37519	0.21775419355	2010	0.55722623715	9.761145	0.0571	0.8851
16.000	17.000	16.500	2.63062	0.15943151515	2009	0.36863338280	6.758240	0.0545	0.8993
17.000	18.000	17.500	1.95714	0.11183657143	2008	0.23299933951	4.464360	0.0522	0.9135
18.000	19.000	18.500	1.37770	0.07447027027	2007	0.13984591866	2.796940	0.0500	0.9250
19.000	20.000	19.500	0.91035	0.04668461538	2006	0.07926847584	1.652915	0.0480	0.9360
20.000	21.000	20.500	0.56084	0.02735804878	2005	0.04224714376	0.917320	0.0461	0.9451
21.000	22.000	21.500	0.32136	0.01494697674	2004	0.02109463100	0.476220	0.0443	0.9525
22.000	23.000	22.500	0.17231	0.00765822222	2003	0.00979203152	0.229385	0.0427	0.9608
23.000	24.000	23.500	0.08679	0.00369319149	2002	0.00411632466	0.099835	0.0412	0.9682
24.000	25.000	24.500	0.03893	0.00158897959	2001	0.00147523912	0.036975	0.0399	0.9776
25.000	26.000	25.500	0.01385	0.00054313725	2000	0.00040918070	0.010585	0.0387	0.9869
26.000	27.000	26.500	0.00330	0.00012452830	1999	0.00007534793	0.002010	0.0375	0.9938
27.000	28.000	27.500	0.00035	0.00001272727	1998	0.00000672014	0.000185	0.0363	0.9983
28.000	28.100	28.050	0.00001	0.00000035651	1997	0.00000001783	0.000001	0.0178	1.0000
TOTAL			100.00000						

Each equal life group's whole life annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3), except that for the first age interval, the annual accrual is set equal to the group's size.

Columns 6 through 10 show the derivation of the whole life annual factor and accrued factor for each vintage based on the data developed in the first five columns. The year installed is shown in column 6. For all vintages other than the first and last year (2026 and 1998), the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For

example, the figure 11.78901572523 for 2025 equals one-half of 0.25324000000 plus all the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the equal life group for that interval expires at the midpoint of the current year.

The summation of annual accruals (column 7) for installations during 2026 is calculated on the basis of an in-service date at the midpoint of the first nine months, i.e., four and one-half months prior to September 30. Since the overall calculation is centered on September 30, 2026, the accrual for 2026 installations (during the first nine months) represents only 0.875 of one year, 0.375 of a year prior to September 30 plus one-half year following September 30. For this reason, the first figure in column 7, for vintage 2026, equals the group annual accrual for 2026 plus 0.875 of the group annual accruals for each of the subsequent years.

The average percent surviving, derived from the Iowa 10-L2.5 survivor curve, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8).

The accrued depreciation factor, shown in column 10, equals the annual factor multiplied by the age of the group at September 30, 2026.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during

which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391.00	Office Furniture and Equipment	
	Furniture	20
	Equipment	10
	Computer Equipment	5
	Software	10
393.00	Stores Equipment	20
394.00	Tools, Shop and Garage Equipment	20
395.00	Laboratory Equipment	20
397.00	Communication Equipment	10
398.00	Miscellaneous Equipment	15

For the purpose of calculating annual amortization amounts at September 30, 2026, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion

to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

AMORTIZATION OF NET SALVAGE

Experienced salvage is incorporated in the results of the study, as was reported on the Company's books and records for the period October 1, 2021 through September 30, 2025, and as estimated for the twelve months ended September 30, 2026. The five-year amortization calculations are shown in Table 4.

Net salvage experienced during the five-year period is presented in this manner to determine the amount of negative net salvage to be amortized for book purposes. In developing the amount to be amortized, the data for the accounts which experienced positive net salvage have been netted with those for accounts which experienced negative net salvage.

In order to be consistent with this manner of recognizing salvage, no adjustments for salvage were made to the annual accruals and accrued depreciation calculated for each individual account. Also, there were no exclusions from the 2022 through 2026 experienced and estimated net salvage amounts that were used to determine the five-year net salvage amortization amount for each account.

PART V. RESULTS OF STUDY

PART V. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages V-4 through V-11 summarize the results of the depreciation study at September 30, 2026 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2026, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the bringforward of the book reserve to September 30, 2026. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2026. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2022 through 2026.

DESCRIPTION OF DETAILED TABULATIONS

Supporting statistical data for the estimates of average service lives and survivor curves, the annual depreciation calculations, and salvage and cost of removal for the years 2022-2026 are presented in three sections.

The section beginning on page VI-1 sets forth, for each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. A cumulative summary, by year installed, for gas plant and the supporting data for the original cost depreciation calculations are presented in the section beginning on page VII-1. The tabulations of experienced and estimated net salvage by year by account for the five-year period, 2022-2026, are presented in the section beginning on page VIII-1.

In Part VI, the survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral

followed by the type curve designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. In cases where only a segment of the estimated curve is used in the depreciation calculation, the numeral used for identification purposes is not a designation of the average life of the group. The titles of the charts indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which the retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation related to original cost are presented in Part VII and indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life expectancy and the calculated annual accrual.

Detailed tabulations setting forth the cost of removal and salvage amounts, by plant account for each year, are presented beginning on page VIII-2. The total salvage and removal costs, by year, were used to calculate the five-year net salvage amortization presented in Table 4 in Part V.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION			0	0	0	-	0
329	OTHER STRUCTURES			0	0	0	-	0
332	FIELD LINES			0	0	0	-	0
335	DRILLING AND CLEANING EQUIPMENT			0	0	0	-	0
TOTAL PRODUCTION PLANT				**0**	**0**	**0**	**-**	**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	583,277	284,883	1.28	11,125
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	156,987	5,229	0.17	283
367	MAINS		75 - R2.5	39,468,181	23,526,057	15,942,124	1.02	403,112
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2.5	6,172,834	4,347,592	1,825,242	1.43	88,553
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,505,204	2,549,221	955,983	2.32	81,415
371	OTHER EQUIPMENT		35 - R2.5	140,637	133,995	6,642	0.62	865
371.1	TESTING EQUIPMENT		20 - R3	210,011	172,428	37,583	2.10	4,401
TOTAL TRANSMISSION PLANT				**50,527,243**	**31,469,557**	**19,057,686**	**1.17**	**589,754**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,374,004	1,551,251	1,822,753	1.27	42,899
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	7,923,019	3,693,851	4,229,168	1.87	148,281
376.1	MAINS - PRIMARILY STEEL		75 - R2.5	787,125,750	211,746,999	575,378,751	1.52	11,926,394
376.2	MAINS - CAST IRON	09-2027	65 - R1	664,766	664,766	0	0.19	1,286
376.3	MAINS - PLASTIC		68 - R3	2,166,671,780	390,033,008	1,776,638,772	1.64	35,578,052
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	305,201	261,046	44,155	1.68	5,135
376.7	REG AFUDC		40 - SQ	1,322,088	300,224	1,021,864	2.50	33,052
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		48 - S0	191,451,499	46,205,293	145,246,206	2.69	5,146,078
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R1.5	81,779,825	16,033,091	65,746,734	2.86	2,335,776
380	SERVICES		45 - R2	1,799,933,111	485,016,289	1,314,916,822	2.65	47,737,596
381	METERS		36 - R2	160,820,610	67,493,856	93,326,754	2.72	4,376,115
381.1	METERS - ERTS		17 - S3	44,949,985	19,347,248	25,602,737	6.83	3,070,865
382	METER INSTALLATIONS		45 - R2	147,330,759	50,079,255	97,251,504	2.41	3,546,966
383	HOUSE REGULATORS		45 - R2	10,274,123	5,133,343	5,140,780	2.66	273,178
384	HOUSE REGULATOR INSTALLATIONS		45 - R2	17,829,357	9,800,803	8,028,554	1.83	326,258
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	41,443,487	21,130,913	20,312,574	1.92	795,232
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		45 - R2	68,824	42,958	25,866	2.15	1,483
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R1.5	1,180,774	632,918	547,856	2.24	26,424
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,705	0	-	0
387	OTHER EQUIPMENT		40 - R2.5	5,308,206	3,316,734	1,991,472	1.68	89,055
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,485,147	5,517	0.22	3,208
TOTAL DISTRIBUTION PLANT				**5,471,272,537**	**1,333,993,698**	**4,137,278,839**	**2.11**	**115,463,333**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS*	168,008,808	55,336,908	112,671,900	3.93	6,597,138
390.3	CNG STATIONS		15 - S3	7,022,614	251,058	6,771,556	7.15	501,969
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,843,693	2,231,975	3,611,718	5.62	328,671
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	211,671	89,606	122,065	11.21	23,727
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	14,016,581	7,096,550	6,920,031	20.83	2,919,208
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	5,446,944	2,343,072	3,103,872	8.95	487,469
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	44,342,195	10,694,286	33,647,909	6.60	2,925,010
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,647,964	3,148,010	1,499,954	8.39	390,041
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	50,841,189	21,105,714	29,735,475	10.13	5,150,277
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLI		12 - L3	7,595,119	3,663,559	3,931,560	7.93	602,011
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	11,013,953	4,673,510	6,340,443	7.93	873,323
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,932,322	1,338,963	1,593,359	6.18	181,305
393	STORES EQUIPMENT		20 - SQ	15,838	7,849	7,989	4.99	791
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	45,410,964	17,652,042	27,758,922	5.14	2,333,105
395	LABORATORY EQUIPMENT		20 - SQ	437,779	200,930	236,849	5.13	22,439
396	POWER OPERATED EQUIPMENT		16 - L2	13,798,162	6,098,760	7,699,402	6.38	880,798
397	COMMUNICATION EQUIPMENT		10 - SQ	3,095,450	1,216,151	1,879,299	10.48	324,268
398	MISCELLANEOUS EQUIPMENT		15 - SQ	1,936,970	1,208,168	728,802	3.18	61,603
399	OTHER TANGIBLE PROPERTY			0	0	0	-	0
TOTAL GENERAL PLANT				**386,618,216**	**138,357,111**	**248,261,105**	**6.36**	**24,603,153**
TOTAL DEPRECIABLE GAS PLANT				**5,908,417,996**	**1,503,820,366**	**4,404,597,630**	**2.38**	**140,656,240**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE		CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
NONDEPRECIABLE PLANT								
301 ORGANIZATION			166,478					
302 FRANCHISES AND CONSENTS			193,597					
303 MISCELLANEOUS INTANGIBLE PLANT			289,868					
365.1 LAND			47,323					
374.1 LAND AND LAND RIGHTS - LAND			803,858					
374.2 LAND AND LAND RIGHTS - LAND RIGHTS			7,459,999					
389.1 LAND AND LAND RIGHTS - LAND			7,936,471					
389.2 LAND AND LAND RIGHTS - LAND RIGHTS			1,313					
TOTAL NONDEPRECIABLE PLANT			**16,898,907**					
TOTAL GAS PLANT			**5,925,316,903**					
OTHER UTILITY PLANT								
COMMON PLANT								
301 ORGANIZATION (NONDEPRECIABLE)			138,964					
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108					
390.1 STRUCTURES AND IMPROVEMENTS								
UGI HEADQUARTERS BUILDING - DENVER	01-2069	70 - R1	35,116,171	6,755,017	28,361,154	2.55		895,246
READING DATA CENTER	09-2073	70 - R1	20,414,469	1,880,978	18,533,491	2.84		580,484
KNITTING MILLS OFFICE	06-2050	70 - R1	1,382,240	261,435	1,120,805	3.94		54,514
TOTAL ACCOUNT 390.1			*56,912,880*	*8,897,430*	*48,015,450*	*2.69*		*1,530,244*
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,926,544	1,481,740	3,444,804	5.12		252,410
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	0	0	0	20.00	**	0
TOTAL COMMON PLANT			**68,925,496**	**10,379,170**	**51,460,254**	**2.88**		**1,782,654**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%			**61,419,509**	**9,248,878**	**45,856,232**			**1,588,523**
INFORMATION SERVICES (IS)								
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,877,324	9,593,313	8,284,011	19.49		3,483,451
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
SUCCESS FACTORS	09-2024	SQUARE	2,803,866	2,803,866	0	-		0
UNITE ERP	09-2034	SQUARE	10,695,816	4,583,616	6,112,200	7.14		764,025
TOTAL ACCOUNT 391.2			*13,499,682*	*7,387,482*	*6,112,200*	*5.66*		*764,025*
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	98,427,853	28,933,224	69,494,629	9.89		9,735,400
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,033,083	73,969,743	60,063,340	6.82		9,134,993
TOTAL INFORMATION SERVICES			**263,837,942**	**119,883,762**	**143,954,180**	**8.76**		**23,117,869**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%			**223,787,342**	**101,685,407**	**122,101,935**			**19,608,576**
EMPIRE YARD BUILDING								
390.1 STRUCTURES AND IMPROVEMENTS			12,568,452	8,904,887	3,663,565	1.50		188,254
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,642,697**	**1,163,869**	**478,828**			**24,605**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**283,564,154**	**109,770,416**	**167,479,339**			**21,172,494**
TOTAL PLANT IN SERVICE			**6,208,881,057**	**1,613,590,782**	**4,572,076,969**			**161,828,734**
AMORTIZATION OF NEGATIVE NET SALVAGE								**8,697,564**
GRAND TOTAL			**6,208,881,057**	**1,613,590,782**	**4,572,076,969**			**170,526,298**

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** RATE TO APPLY TO FUTURE PLANT IN-SERVICE

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2025 PROJECTED TO SEPTEMBER 30, 2026

ACCOUNT		BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GAS PLANT										
PRODUCTION PLANT										
305	MANUFACTURED GAS PLANT SITE REMEDIATION	23,039	0	(23,039)	0	0	0	0	0	0.00
329	OTHER STRUCTURES	0	0	0	0	0	0	0	0	0.00
332	FIELD LINES	0	0	0	0	0	0	0	0	0.00
335	DRILLING AND CLEANING EQUIPMENT	0	0	0	0	0	0	0	0	0.00
TOTAL PRODUCTION PLANT		**23,039**	**0**	**(23,039)**	**0**	**0**	**0**	**0**	**0**	**0.00**
TRANSMISSION PLANT										
365.2	RIGHTS-OF-WAY	571,904	11,373	0	0	0	0	0	583,277	67.19
366	STRUCTURES AND IMPROVEMENTS	156,695	292	0	0	0	0	0	156,987	96.78
367	MAINS	23,115,954	406,522	3,581	0	0	0	0	23,526,057	59.61
369	MEASURING AND REGULATING STATION EQUIPMENT	4,255,146	90,741	1,705	0	0	0	0	4,347,592	70.43
370	COMMUNICATION EQUIPMENT	2,462,642	86,579	0	0	0	0	0	2,549,221	72.73
371	OTHER EQUIPMENT	133,053	942	0	0	0	0	0	133,995	95.28
371.1	TESTING EQUIPMENT	167,850	4,578	0	0	0	0	0	172,428	82.10
TOTAL TRANSMISSION PLANT		**30,863,244**	**601,027**	**5,286**	**0**	**0**	**0**	**0**	**31,469,557**	**62.28**
DISTRIBUTION PLANT										
374.2	RIGHTS-OF-WAY	1,508,064	43,187	0	0	0	0	0	1,551,251	45.98
375	STRUCTURES AND IMPROVEMENTS	3,577,081	138,089	2,857	(16,926)	0	(7,250)	0	3,693,851	46.62
376.1	MAINS - PRIMARILY STEEL	202,628,288	11,746,823	1,490,006	(2,936,060)	0	(1,182,058)	0	211,746,999	26.90
376.2	MAINS - CAST IRON	605,269	30,811	515,594	0	0	0	(486,908)	664,766	100.00
376.3	MAINS - PLASTIC	359,244,271	34,074,195	699,805	(3,714,736)	0	(757,435)	486,908	390,033,008	18.00
376.5	MAINS - PRIMARILY WROUGHT IRON	255,480	5,566	0	0	0	0	0	261,046	85.53
376.7	REG AFUDC	267,172	33,052	0	0	0	0	0	300,224	22.71
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	41,528,725	4,717,138	226,543	(213,690)	0	(53,423)	0	46,205,293	24.13
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	13,438,274	2,507,090	87,727	0	0	0	0	16,033,091	19.61
380	SERVICES	460,225,389	46,015,175	4,744,153	(18,697,119)	0	(7,271,309)	0	485,016,289	26.95
381	METERS	64,992,744	4,216,422	28,304	(1,743,614)	0	0	0	67,493,856	41.97
381.1	METERS - ERTS	17,039,782	3,173,164	6,109	(871,807)	0	0	0	19,347,248	43.04
382	METER INSTALLATIONS	47,684,946	3,479,884	133,257	(877,552)	0	(341,280)	0	50,079,255	33.99
383	HOUSE REGULATORS	3,921,107	340,659	871,577	0	0	0	0	5,133,343	49.96
384	HOUSE REGULATOR INSTALLATIONS	9,463,445	333,586	3,772	0	0	0	0	9,800,803	54.97
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	19,978,680	809,231	24,666	(7,802)	0	326,138	0	21,130,913	50.99
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	(55,879)	9,858	155	0	0	0	88,824	42,958	62.42
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	706,337	15,143	247	0	0	0	(88,809)	632,918	53.60
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,720	0	0	0	0	0	(15)	24,705	100.00
387	OTHER EQUIPMENT	3,225,607	91,127	0	0	0	0	0	3,316,734	62.48
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,481,718	3,429	0	0	0	0	0	1,485,147	99.63
TOTAL DISTRIBUTION PLANT		**1,251,741,220**	**111,783,629**	**8,834,772**	**(29,079,306)**	**0**	**(9,286,617)**	**0**	**1,333,993,698**	**24.38**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2025 PROJECTED TO SEPTEMBER 30, 2026

ACCOUNT	BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GENERAL PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	49,470,174	6,110,970	131,769	(345,054)	0	(30,951)	0	55,336,908	32.94
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	0	0	0	0.00
390.3 CNG STATIONS	0	251,058	0	0	0	0	0	251,058	0.00
391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,973,088	322,361	0	(18,368)	0	0	(45,106)	2,231,975	38.19
391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	122,642	20,298	0	(48,045)	0	0	(5,289)	89,606	42.33
391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	4,391,081	2,762,253	0	(62,073)	0	0	5,289	7,096,550	50.63
391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,333,192	0	0	(4,378,298)	0	0	45,106	0	0.00
391.41 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	3,667,639	415,662	0	(1,740,229)	0	0	0	2,343,072	43.02
391.42 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	16,378,755	2,673,517	0	(8,357,986)	0	0	0	10,694,286	24.12
392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	2,777,810	411,122	0	(45,469)	4,547	0	0	3,148,010	67.73
392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	18,137,557	4,621,465	(871,601)	(868,564)	86,857	0	0	21,105,714	41.51
392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	3,144,919	585,510	0	(74,300)	7,430	0	0	3,663,559	48.24
392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	3,935,541	834,939	0	(107,744)	10,774	0	0	4,673,510	42.43
392.5 TRANSPORTATION EQUIPMENT - TRAILERS	1,191,005	173,776	0	(28,686)	2,868	0	0	1,338,963	45.66
393 STORES EQUIPMENT	7,057	792	0	0	0	0	0	7,849	49.56
394 TOOLS, SHOP AND GARAGE EQUIPMENT	16,560,440	2,318,485	4,379	(1,231,262)	0	0	0	17,652,042	38.87
395 LABORATORY EQUIPMENT	178,472	22,458	0	0	0	0	0	200,930	45.90
396 POWER OPERATED EQUIPMENT	5,174,132	924,628	0	0	0	0	0	6,098,760	44.20
397 COMMUNICATION EQUIPMENT	825,767	387,864	2,520	0	0	0	0	1,216,151	39.29
398 MISCELLANEOUS EQUIPMENT	1,055,236	93,140	156,533	(96,741)	0	0	0	1,208,168	62.37
399 OTHER TANGIBLE PROPERTY	16,032	0	0	(16,032)	0	0	0	0	0.00
TOTAL GENERAL PLANT	**133,340,539**	**22,930,298**	**(576,400)**	**(17,418,851)**	**112,476**	**(30,951)**	**0**	**138,357,111**	**36.45**
TOTAL DEPRECIABLE GAS PLANT	**1,415,968,042**	**135,314,954**	**8,240,619**	**(46,498,157)**	**112,476**	**(9,317,568)**	**0**	**1,503,820,366**	**25.48**
OTHER UTILITY PLANT									
COMMON PLANT									
390.1 STRUCTURES AND IMPROVEMENTS									
UGI HEADQUARTERS BUILDING - DENVER	5,809,287	908,409	0	0	0	0	0	6,717,696	19.13
READING DATA CENTER	1,306,157	614,476	0	0	0	0	0	1,920,633	9.41
KNITTING MILLS OFFICE	203,120	55,981	0	0	0	0	0	259,101	18.75
TOTAL ACCOUNT 390.1	*7,318,564*	*1,578,866*	*0*	*0*	*0*	*0*	*0*	*8,897,430*	
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,407,352	238,215	0	0	0	0	(163,827)	1,481,740	30.08
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	748,671	163,878	0	(1,076,376)	0	0	163,827	0	0.00
TOTAL COMMON PLANT	**9,474,587**	**1,980,959**	**0**	**(1,076,376)**	**0**	**0**	**0**	**10,379,170**	**16.78**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%	**8,442,804**	**1,765,233**	**0**	**(959,159)**	**0**	**0**	**0**	**9,248,878**	
INFORMATION SERVICES (IS)									
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5,819,410	3,773,903	0	0	0	0	0	9,593,313	53.66
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE									
SUCCESS FACTORS	2,803,866	0	0	0	0	0	0	2,803,866	100.00
UNITE ERP	3,819,935	763,681	0	0	0	0	0	4,583,616	42.85
TOTAL ACCOUNT 391.2	*6,623,801*	*763,681*	*0*	*0*	*0*	*0*	*0*	*7,387,482*	
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	35,342,141	7,130,207	0	(13,539,124)	0	0	0	28,933,224	29.40
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	65,398,509	9,119,459	0	(548,225)	0	0	0	73,969,743	55.19
TOTAL INFORMATION SERVICES	**113,183,861**	**20,787,250**	**0**	**(14,087,349)**	**0**	**0**	**0**	**119,883,762**	**45.44**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%	**96,002,551**	**17,631,745**	**0**	**(11,948,889)**	**0**	**0**	**0**	**101,685,407**	
EMPIRE YARD BUILDING									
390.1 STRUCTURES AND IMPROVEMENTS	8,652,881	196,778	55,228	0	0	0 #	0	8,904,887	70.85
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,130,932**	**25,719**	**7,218**	**0**	**0**	**0**	**0**	**1,163,869**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION	**103,314,423**	**19,371,259**	**(7,218)**	**(12,908,048)**	**0**	**0**	**0**	**109,770,416**	
TOTAL DEPRECIABLE PLANT IN SERVICE	**1,519,282,465**	**154,686,213**	**8,233,401**	**(59,406,205)**	**112,476**	**(9,317,568)**	**0**	**1,613,590,782**	

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2026

ACCOUNT		BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GAS PLANT									
PRODUCTION PLANT									
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0	0	0	0	0	-	0
329	OTHER STRUCTURES	0	0	0	0	0	0	-	0
332	FIELD LINES	0	0	0	0	0	0	-	0
335	DRILLING AND CLEANING EQUIPMENT	0	0	0	0	0	0	-	0
TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**		**0**
TRANSMISSION PLANT									
365.2	RIGHTS-OF-WAY	868,160	0	0	0	868,160	868,160	1.31	11,373
366	STRUCTURES AND IMPROVEMENTS	162,216	0	0	0	162,216	162,216	0.18	292
367	MAINS	39,468,181	0	0	0	39,468,181	39,468,181	1.03	406,522
369	MEASURING AND REGULATING STATION EQUIPMENT	6,172,834	0	0	0	6,172,834	6,172,834	1.47	90,741
370	COMMUNICATION EQUIPMENT	3,505,204	0	0	0	3,505,204	3,505,204	2.47	86,579
371	OTHER EQUIPMENT	140,637	0	0	0	140,637	140,637	0.67	942
371.1	TESTING EQUIPMENT	210,011	0	0	0	210,011	210,011	2.18	4,578
TOTAL TRANSMISSION PLANT		**50,527,243**	**0**	**0**	**0**	**50,527,243**	**50,527,243**		**601,027**
DISTRIBUTION PLANT									
374.2	RIGHTS-OF-WAY	3,374,004	0	0	0	3,374,004	3,374,004	1.28	43,187
375	STRUCTURES AND IMPROVEMENTS	7,180,945	759,000	(16,926)	0	7,923,019	7,551,982	1.80	138,089
376.1	MAINS - PRIMARILY STEEL	761,490,737	28,571,074	(2,936,060)	0	787,125,751	774,308,244	1.52	11,746,823
376.2	MAINS - CAST IRON	664,766	0	0	0	664,766	664,766	4.64	30,811
376.3	MAINS - PLASTIC	1,988,393,622	181,992,894	(3,714,736)	0	2,166,671,780	2,077,532,701	1.64	34,074,195
376.5	MAINS - PRIMARILY WROUGHT IRON	305,201	0	0	0	305,201	305,201	1.82	5,566
376.7	REG AFUDC	1,322,088	0	0	0	1,322,088	1,322,088	2.50	33,052
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	164,220,812	27,444,377	(213,690)	0	191,451,499	177,836,156	2.65	4,717,138
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	81,779,825	0	0	0	81,779,825	81,779,825	3.06	2,507,090
380	SERVICES	1,684,480,735	134,149,497	(18,697,119)	0	1,799,933,113	1,742,206,924	2.64	46,015,175
381	METERS	152,199,760	10,364,463	(1,743,614)	0	160,820,609	156,510,185	2.70	4,216,422
381.1	METERS - ERTS	40,639,561	5,182,232	(871,807)	0	44,949,986	42,794,774	7.45	3,173,164
382	METER INSTALLATIONS	141,911,982	6,296,328	(877,552)	0	147,330,758	144,621,370	2.41	3,479,884
383	HOUSE REGULATORS	10,274,123	0	0	0	10,274,123	10,274,123	3.32	340,659
384	HOUSE REGULATOR INSTALLATIONS	17,829,357	0	0	0	17,829,357	17,829,357	1.87	333,586
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	40,449,313	1,001,976	(7,802)	0	41,443,487	40,946,400	1.97	809,231
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	267,063	0	0	(198,239)	68,824	167,944	5.87	9,858
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	982,535	0	0	198,239	1,180,774	1,081,655	1.40	15,143
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	24,705	24,705	-	0
387	OTHER EQUIPMENT	5,308,206	0	0	0	5,308,206	5,308,206	1.71	91,127
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	0	0	0	1,490,664	1,490,664	0.23	3,429
TOTAL DISTRIBUTION PLANT		**5,104,590,004**	**395,761,841**	**(29,079,306)**	**0**	**5,471,272,539**	**5,287,931,272**	2.11	**111,783,629**
GENERAL PLANT									
390.1	STRUCTURES AND IMPROVEMENTS	159,009,347	9,344,513	(345,054)	0	168,008,806	163,509,077	3.80	6,110,970
390.3	CNG STATIONS	-	7,022,614	0	0	7,022,614	3,511,307	7.15	251,058
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,762,063	100,000	(18,368)	0	5,843,695	5,802,879	5.55	322,361
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	209,716	50,000	(48,045)	0	211,671	210,694	9.14	20,298
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	11,611,467	2,467,186	(62,073)	0	14,016,580	12,814,024	21.56	2,762,253
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,378,298	0	(4,378,298)	0	0	2,189,149	-	0
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	7,187,173	1	(1,740,229)	0	5,446,945	6,317,059	6.58	415,662
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	52,700,181	0	(8,357,986)	0	44,342,195	48,521,188	5.51	2,673,517
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	4,238,742	454,690	(45,469)	0	4,647,963	4,443,353	9.14	411,122
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	43,024,106	8,685,648	(868,564)	0	50,841,190	46,932,648	9.87	4,621,465
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	6,926,421	742,998	(74,300)	0	7,595,119	7,260,770	8.04	585,510
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	10,044,251	1,077,447	(107,744)	0	11,013,954	10,529,103	7.92	834,939
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	2,674,151	286,856	(28,686)	0	2,932,322	2,803,237	6.17	173,776
393	STORES EQUIPMENT	15,838	0	0	0	15,838	15,838	5.00	792
394	TOOLS, SHOP AND GARAGE EQUIPMENT	44,808,230	1,833,996	(1,231,262)	0	45,410,964	45,109,597	5.14	2,318,485
395	LABORATORY EQUIPMENT	437,779	0	0	0	437,779	437,779	5.13	22,458
396	POWER OPERATED EQUIPMENT	13,798,162	0	0	0	13,798,162	13,798,162	6.70	924,628
397	COMMUNICATION EQUIPMENT	3,095,450	0	0	0	3,095,450	3,095,450	12.53	387,864
398	MISCELLANEOUS EQUIPMENT	1,510,050	523,660	(96,741)	0	1,936,969	1,723,510	5.50	93,140
399	OTHER TANGIBLE PROPERTY	16,032	0	(16,032)	0	0	8,016	-	0
TOTAL GENERAL PLANT		**371,447,458**	**32,589,609**	**(17,418,851)**	**0**	**386,618,216**	**379,032,837**		**22,930,298**
TOTAL DEPRECIABLE GAS PLANT		**5,526,564,705**	**428,351,451**	**(46,498,157)**	**0**	**5,908,417,998**	**5,717,491,352**		**135,314,954**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2026

ACCOUNT		BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
NONDEPRECIABLE PLANT									
301	ORGANIZATION	166,478	0	0	0	166,478	166,478		
302	FRANCHISES AND CONSENTS	193,597	0	0	0	193,597	193,597		
303	MISCELLANEOUS INTANGIBLE PLANT	289,868	0	0	0	289,868	289,868		
365.1	LAND	47,323	0	0	0	47,323	47,323		
374.1	LAND AND LAND RIGHTS - LAND	803,858	0	0	0	803,858	803,858		
374.2	LAND AND LAND RIGHTS - LAND RIGHTS	7,459,999	0	0	0	7,459,999	7,459,999		
389.1	LAND AND LAND RIGHTS - LAND	7,330,889	605,582	0	0	7,936,471	7,633,680		
389.2	LAND AND LAND RIGHTS - LAND RIGHTS	1,313	0	0	0	1,313	1,313		
TOTAL NONDEPRECIABLE PLANT		**16,293,325**	**605,582**	**0**	**0**	**16,898,907**	**16,596,116**		
TOTAL GAS PLANT		**5,542,858,030**	**428,957,033**	**(46,498,157)**	**0**	**5,925,316,905**	**5,734,087,467**		
OTHER UTILITY PLANT									
COMMON PLANT									
301	ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964	138,964		
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108	6,947,108		
390.1	STRUCTURES AND IMPROVEMENTS								
	UGI HEADQUARTERS BUILDING - DENVER	34,761,419	354,752	0	0	35,116,171	34,938,795	2.60	908,409
	READING DATA CENTER	20,414,469	0	0	0	20,414,469	20,414,469	3.01	614,476
	KNITTING MILLS OFFICE	1,382,240	0	0	0	1,382,240	1,382,240	4.05	55,981
	TOTAL ACCOUNT 390.1	*56,558,128*	*354,752*	*0*	*0*	*56,912,880*	*56,735,504*		*1,578,866*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,876,544	50,000	0	0	4,926,544	4,901,544	4.86	238,215
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	1,076,376	0	(1,076,376)	0	0	538,188	30.45	163,878
TOTAL COMMON PLANT		**69,597,120**	**404,752**	**(1,076,376)**	**0**	**68,925,496**	**69,261,308**		**1,980,959**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%		**62,017,994**	**360,675**	**(959,159)**	**0**	**61,419,509**	**61,718,752**		**1,765,233**
INFORMATION SERVICES (IS)									
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	17,877,324	0	0	0	17,877,324	17,877,324	21.11	3,773,903
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
	SUCCESS FACTORS	2,803,866	0	0	0	2,803,866	2,803,866	-	0
	UNITE ERP	10,695,816	0	0	0	10,695,816	10,695,816	7.14	763,681
	TOTAL ACCOUNT 391.2	13,499,683	0	0	0	13,499,682	13,499,682		763,681
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	63,317,686	48,649,291	(13,539,124)	0	98,427,853	80,872,770	7.64	7,130,207
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	134,581,308	0	(548,225)	0	134,033,083	134,307,195	6.79	9,119,459
TOTAL INFORMATION SERVICES		**229,276,000**	**48,649,291**	**(14,087,349)**	**0**	**263,837,942**	**246,556,971**		**20,787,250**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%		**194,471,903**	**41,264,328**	**(11,948,889)**	**0**	**223,787,342**	**209,129,623**		**17,631,745**
EMPIRE YARD BUILDING									
390.1	STRUCTURES AND IMPROVEMENTS	12,568,452	0	0	0	12,568,452	12,568,452	1.57	196,778
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%		**1,642,697**	**0**	**0**	**0**	**1,642,697**	**1,642,697**		**25,719**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION		**254,847,200**	**41,625,003**	**(12,908,048)**	**0**	**283,564,154**	**269,205,678**		**19,371,259**
TOTAL PLANT IN SERVICE		**5,797,705,230**	**470,582,036**	**(59,406,205)**	**0**	**6,208,881,059**	**6,003,293,145**		**154,686,213**

* TOTAL ACCRUALS SHOWN ARE BASED ON EACH DISTRICT'S AVERAGE BALANCES

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	2026 GROSS SALVAGE	2026 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	0	0	0	0	0	0	0	0	0	0	0	0
329	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
335	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	464	0	412	0	5,801	0	9,571	0	0	16,247	3,249
369	0	4,906	0	231	0	0	0	0	0	0	5,137	1,027
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**5,370**	**0**	**643**	**0**	**5,801**	**0**	**9,571**	**0**	**0**	**21,385**	**4,276**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	346	0	1,876	0	0	0	12,062	0	7,250	21,534	4,307
376.1	0	749,917	0	1,693,882	0	1,190,708	0	2,102,595	0	1,182,058	6,919,159	1,383,832
376.2	0	270,874	0	633,299	0	682,408	0	899,144	0	0	2,485,725	497,145
376.3	0	1,130,259	0	311,402	0	819,607	0	508,772	0	757,435	3,527,475	705,495
376.5	0	0	0	0	0	0	0	0	0	0	0	0
378	0	278,821	0	206,792	0	165,132	0	313,281	0	53,422	1,017,448	203,490
379	0	98,844	0	85,312	0	43,038	0	196,338	0	0	423,531	84,705
380	0	4,547,451	0	5,345,562	0	4,613,724	0	5,022,669	0	7,271,310	26,800,716	5,360,143
381	0	711	0	35,495	0	48,411	0	74,865	0	0	159,482	31,896
381.1	0	0	0	2,076	0	9,685	0	18,782	0	0	30,543	6,109
382	0	164,128	0	117,424	0	65,380	0	94,530	0	341,280	782,742	156,549
383	0	0	0	806	0	3,328,107	0	1,028,703	0	0	4,357,616	871,523
384	0	2,202	0	82	0	282	0	2,578	0	0	5,144	1,028
385	0	(154)	0	0	0	984	0	87,207	0	(326,138)	(238,101)	(47,619)
386.0	0	0	0	0	0	0	0	774	0	0	774	155
386.1	0	0	0	0	0	208	0	1,025	0	0	1,233	247
386.2	0	0	0	0	0	0	0	0	0	0	0	0
386.3	0	0	0	0	0	0	0	0	0	0	0	0
387	0	0	0	0	0	0	0	0	0	0	0	0
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**7,243,398**	**0**	**8,434,009**	**0**	**10,967,674**	**0**	**10,363,326**	**0**	**9,286,617**	**46,295,023**	**9,259,005**

UGI UTILITIES, INC. - GAS DIVISION

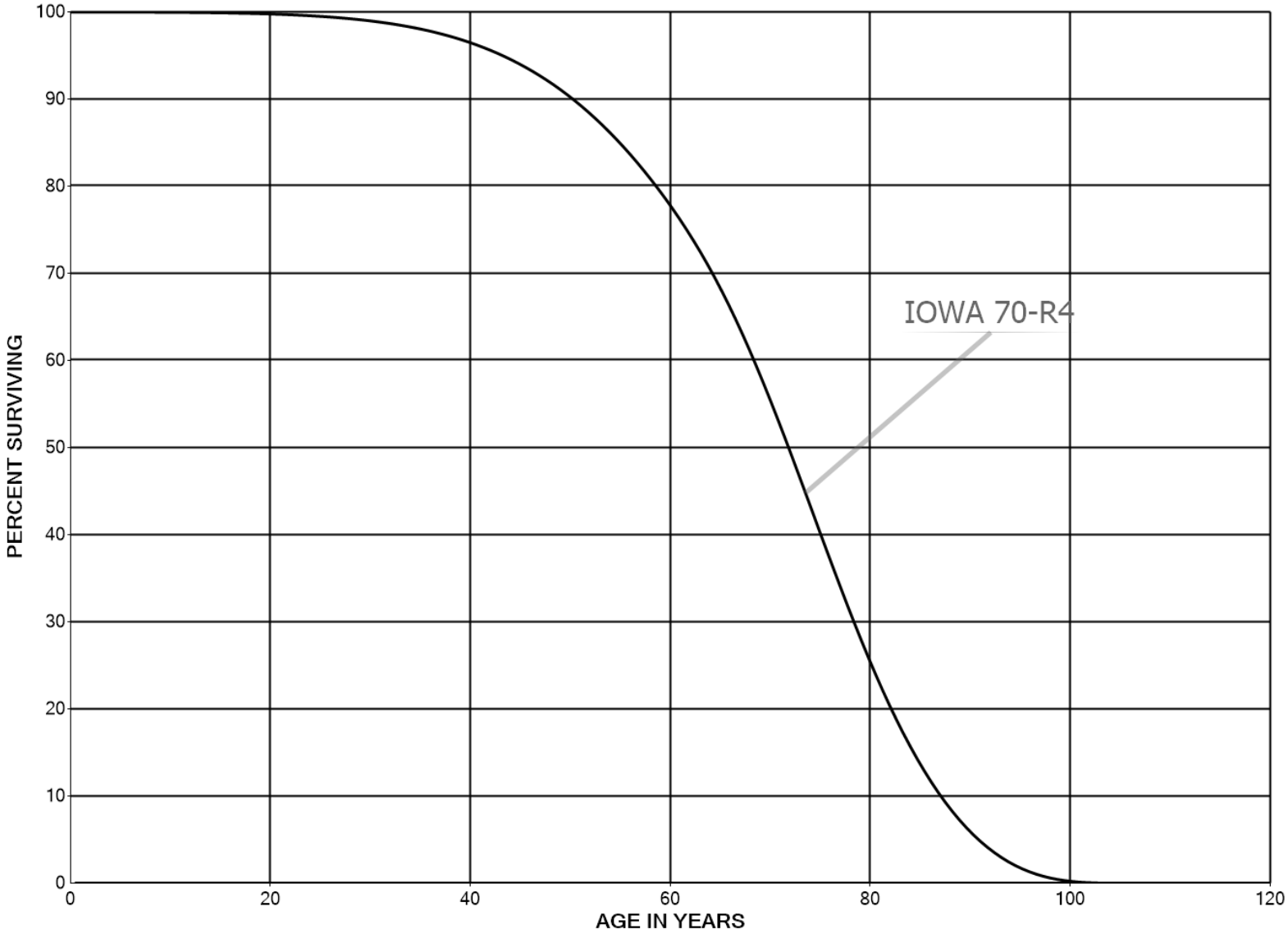
TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	2026 GROSS SALVAGE	2026 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	969	0	395	0	552,200	0	105,144	0	30,951	689,659	137,932
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	(4,547)	0	(4,547)	(909)
392.2	(1,548,910)	0	(887,270)	0	(645,657)	0	(749,272)	0	(86,856)	0	(3,917,966)	(783,593)
392.3	0	0	0	0	0	0	0	0	(7,430)	0	(7,430)	(1,486)
392.4	0	0	0	0	0	0	0	0	(10,774)	0	(10,774)	(2,155)
392.5	0	0	0	0	0	0	0	0	(2,869)	0	(2,869)	(574)
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	21,728	0	167	0	0	0	0	0	0	21,895	4,379
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	11	0	2,889	0	9,703	0	0	12,603	2,520
398	0	150,545	0	79,441	0	74,236	0	86,622	0	0	390,844	78,169
TOTAL	**(1,548,910)**	**173,241**	**(887,270)**	**80,015**	**(645,657)**	**629,324**	**(749,272)**	**201,469**	**(112,476)**	**30,951**	**(2,828,585)**	**(565,717)**
TOTAL GAS PLANT	**(1,548,910)**	**7,422,009**	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**(112,476)**	**9,317,568**	**43,487,822**	**8,697,564**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(1,548,910)**	**7,422,009**	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**(112,476)**	**9,317,568**	**43,487,822**	**8,697,564**

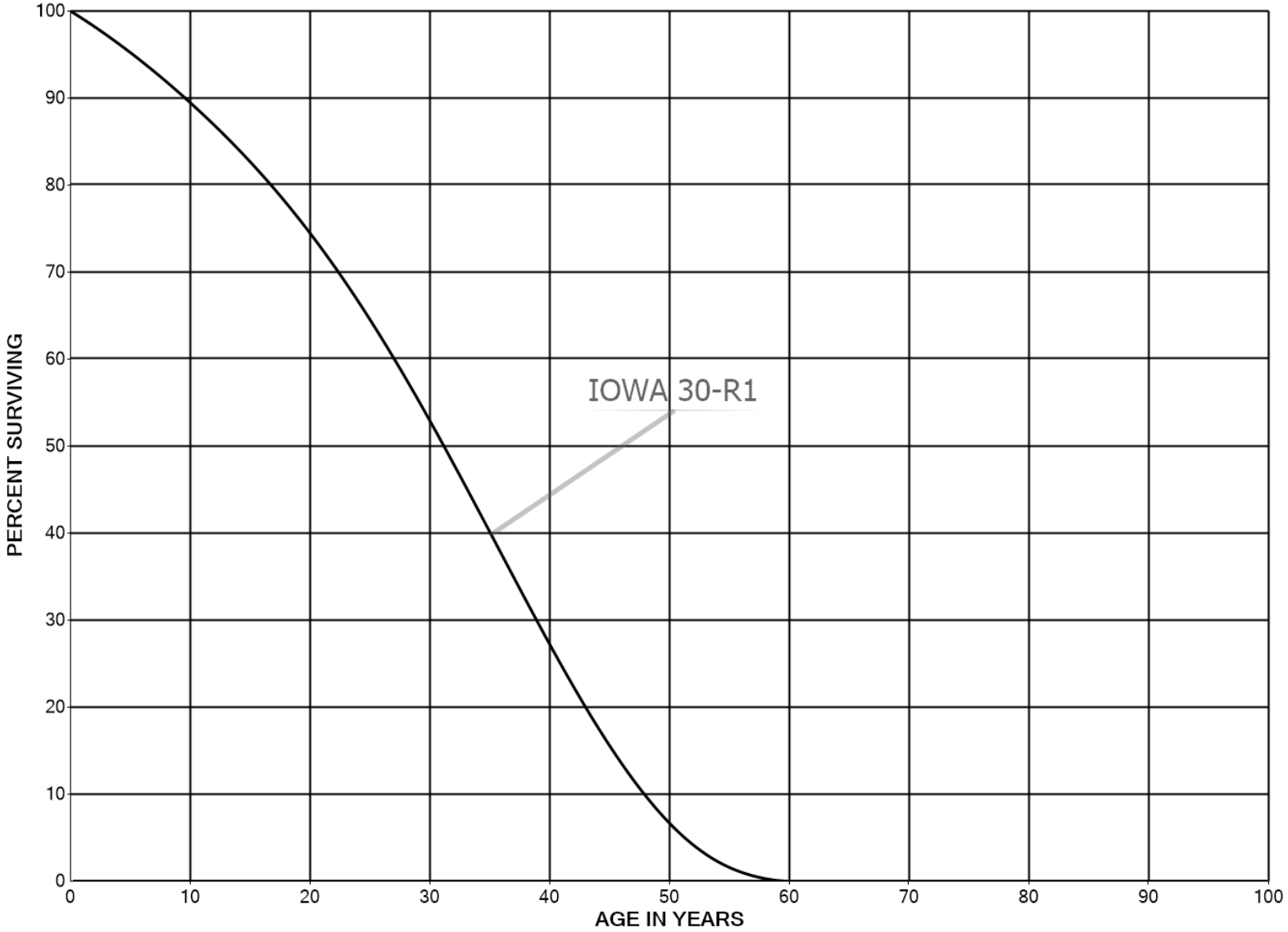
* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART VI. SERVICE LIFE STATISTICS

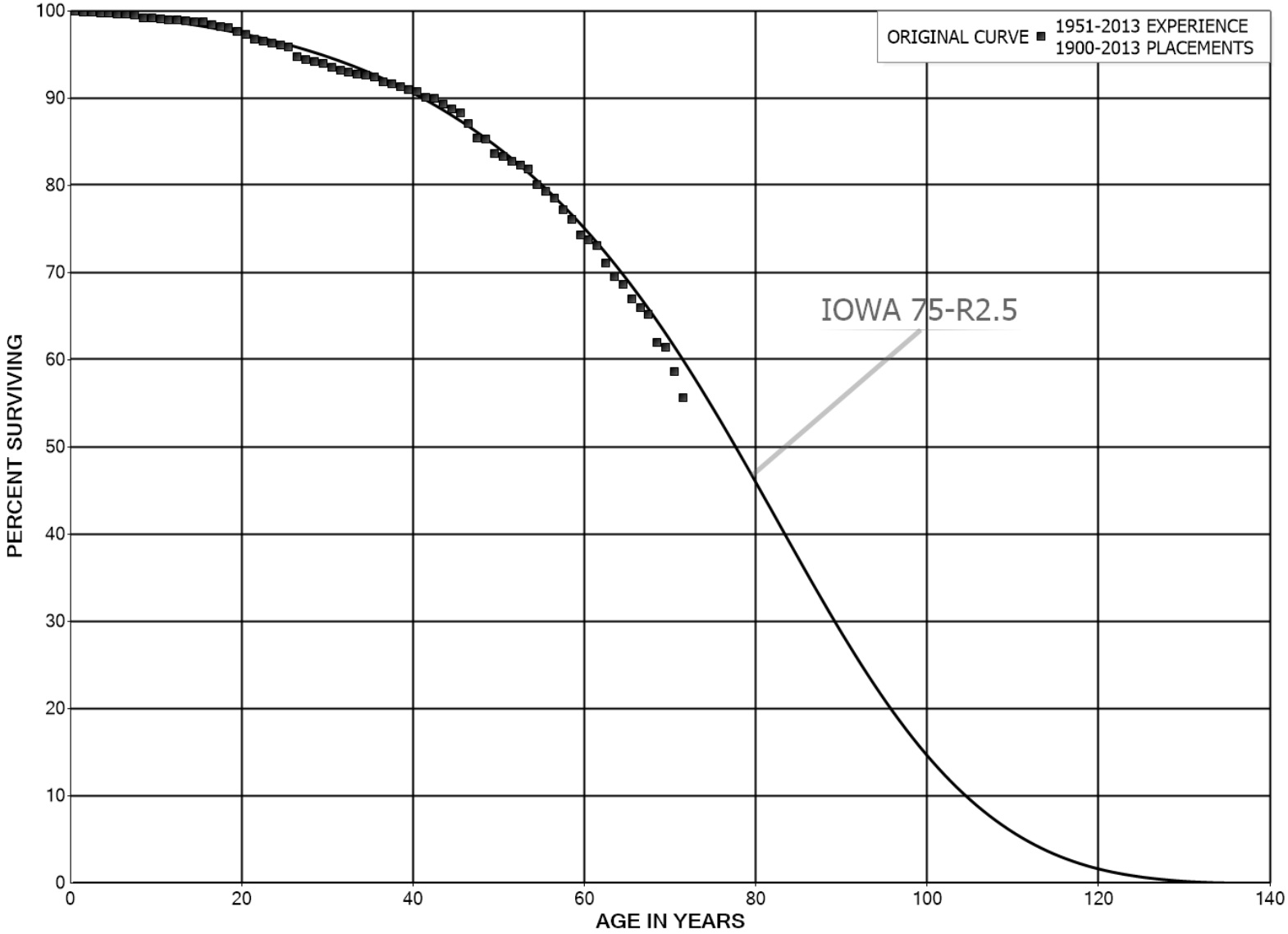
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 365.2 RIGHTS-OF-WAY
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 366 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 367 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	43,850,795	17,230	0.0004	0.9996	100.00
0.5	41,637,546	38,133	0.0009	0.9991	99.96
1.5	41,710,703	29,348	0.0007	0.9993	99.87
2.5	41,698,275	18,241	0.0004	0.9996	99.80
3.5	41,179,742	20,022	0.0005	0.9995	99.76
4.5	41,190,999	25,728	0.0006	0.9994	99.71
5.5	41,007,960	16,986	0.0004	0.9996	99.64
6.5	40,543,199	30,014	0.0007	0.9993	99.60
7.5	40,235,208	126,599	0.0031	0.9969	99.53
8.5	40,056,415	23,786	0.0006	0.9994	99.22
9.5	39,620,574	24,263	0.0006	0.9994	99.16
10.5	37,800,752	34,935	0.0009	0.9991	99.10
11.5	36,175,185	28,922	0.0008	0.9992	99.01
12.5	33,932,562	16,407	0.0005	0.9995	98.93
13.5	32,926,142	32,725	0.0010	0.9990	98.88
14.5	31,097,812	31,843	0.0010	0.9990	98.78
15.5	29,121,771	84,454	0.0029	0.9971	98.68
16.5	28,243,535	46,919	0.0017	0.9983	98.39
17.5	27,750,657	54,606	0.0020	0.9980	98.23
18.5	27,031,445	106,788	0.0040	0.9960	98.04
19.5	25,789,365	92,763	0.0036	0.9964	97.65
20.5	24,529,783	132,147	0.0054	0.9946	97.30
21.5	22,164,999	62,913	0.0028	0.9972	96.77
22.5	21,562,846	48,600	0.0023	0.9977	96.50
23.5	19,129,018	33,878	0.0018	0.9982	96.28
24.5	18,659,552	63,524	0.0034	0.9966	96.11
25.5	18,187,437	191,547	0.0105	0.9895	95.78
26.5	17,523,332	73,112	0.0042	0.9958	94.77
27.5	16,825,941	31,448	0.0019	0.9981	94.38
28.5	16,046,906	48,550	0.0030	0.9970	94.20
29.5	15,473,503	65,299	0.0042	0.9958	93.92
30.5	15,070,050	60,057	0.0040	0.9960	93.52
31.5	14,730,984	34,606	0.0023	0.9977	93.15
32.5	14,447,634	30,637	0.0021	0.9979	92.93
33.5	13,914,882	21,980	0.0016	0.9984	92.73
34.5	13,604,928	21,216	0.0016	0.9984	92.59
35.5	13,259,494	83,249	0.0063	0.9937	92.44
36.5	13,039,123	32,916	0.0025	0.9975	91.86
37.5	12,686,293	40,977	0.0032	0.9968	91.63
38.5	12,200,720	48,919	0.0040	0.9960	91.33

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,797,856	27,669	0.0023	0.9977	90.97
40.5	10,816,130	84,272	0.0078	0.9922	90.75
41.5	10,277,823	15,542	0.0015	0.9985	90.05
42.5	9,379,808	69,088	0.0074	0.9926	89.91
43.5	8,671,839	55,876	0.0064	0.9936	89.25
44.5	8,247,642	38,976	0.0047	0.9953	88.67
45.5	7,994,653	106,439	0.0133	0.9867	88.25
46.5	7,258,790	136,085	0.0187	0.9813	87.08
47.5	6,506,421	12,335	0.0019	0.9981	85.45
48.5	6,367,487	125,000	0.0196	0.9804	85.28
49.5	6,202,931	21,608	0.0035	0.9965	83.61
50.5	6,074,087	40,613	0.0067	0.9933	83.32
51.5	5,985,583	37,752	0.0063	0.9937	82.76
52.5	5,272,897	29,238	0.0055	0.9945	82.24
53.5	4,628,826	98,818	0.0213	0.9787	81.78
54.5	4,221,959	37,702	0.0089	0.9911	80.04
55.5	3,872,626	41,394	0.0107	0.9893	79.32
56.5	2,357,451	37,947	0.0161	0.9839	78.48
57.5	2,237,754	32,611	0.0146	0.9854	77.21
58.5	1,406,680	32,728	0.0233	0.9767	76.09
59.5	1,173,931	8,748	0.0075	0.9925	74.32
60.5	1,142,975	11,119	0.0097	0.9903	73.76
61.5	862,080	23,546	0.0273	0.9727	73.05
62.5	834,417	18,091	0.0217	0.9783	71.05
63.5	822,427	10,162	0.0124	0.9876	69.51
64.5	713,428	18,038	0.0253	0.9747	68.65
65.5	670,448	10,166	0.0152	0.9848	66.92
66.5	641,536	7,461	0.0116	0.9884	65.90
67.5	633,795	31,231	0.0493	0.9507	65.13
68.5	578,263	5,353	0.0093	0.9907	61.92
69.5	566,309	25,005	0.0442	0.9558	61.35
70.5	540,089	28,306	0.0524	0.9476	58.64
71.5	500,149	4,044	0.0081	0.9919	55.57
72.5	484,740	695	0.0014	0.9986	55.12
73.5	483,247	413	0.0009	0.9991	55.04
74.5	480,037	570	0.0012	0.9988	54.99
75.5	477,078	13,539	0.0284	0.9716	54.93
76.5	446,917	2,024	0.0045	0.9955	53.37
77.5	443,482	7,658	0.0173	0.9827	53.13
78.5	422,077	7,166	0.0170	0.9830	52.21

UGI UTILITIES, INC. - GAS DIVISION

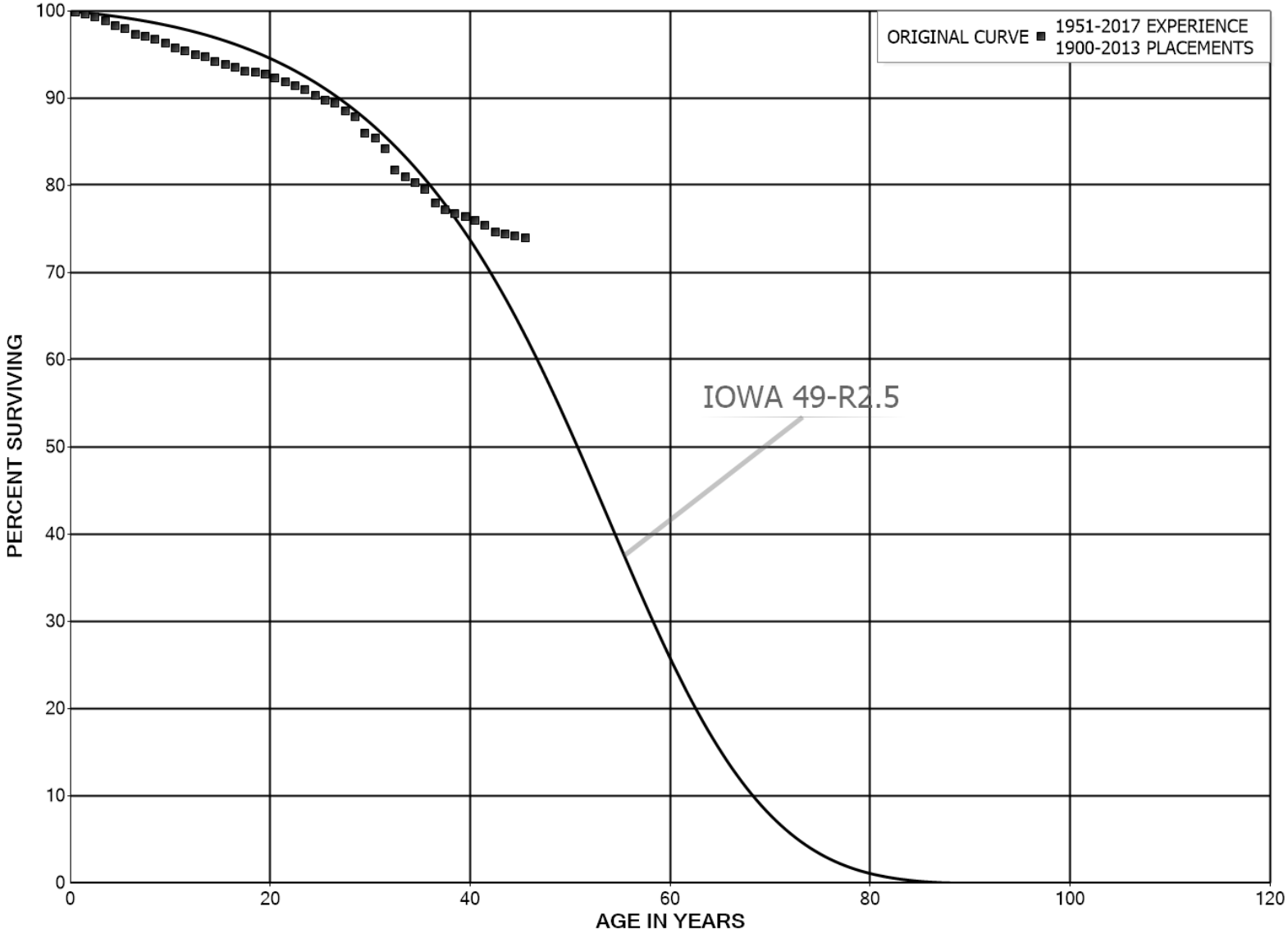
ACCOUNT 367 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	409,437	277	0.0007	0.9993	51.32
80.5	286,341	1,689	0.0059	0.9941	51.29
81.5	283,821	32,605	0.1149	0.8851	50.99
82.5	248,693	1,179	0.0047	0.9953	45.13
83.5	219,985	1,604	0.0073	0.9927	44.92
84.5	218,200		0.0000	1.0000	44.59
85.5	216,028	8,283	0.0383	0.9617	44.59
86.5	161,281	1,815	0.0113	0.9887	42.88
87.5	158,109	186	0.0012	0.9988	42.40
88.5	157,923	867	0.0055	0.9945	42.35
89.5	157,056	1,108	0.0071	0.9929	42.11
90.5	155,912	3,306	0.0212	0.9788	41.82
91.5	152,606	2,135	0.0140	0.9860	40.93
92.5	150,470	3,562	0.0237	0.9763	40.36
93.5	146,908		0.0000	1.0000	39.40
94.5	146,908	764	0.0052	0.9948	39.40
95.5	146,144		0.0000	1.0000	39.20
96.5	146,144	189	0.0013	0.9987	39.20
97.5	145,878		0.0000	1.0000	39.15
98.5	145,878		0.0000	1.0000	39.15
99.5	145,878		0.0000	1.0000	39.15
100.5	144,140		0.0000	1.0000	39.15
101.5	144,140		0.0000	1.0000	39.15
102.5	143,390		0.0000	1.0000	39.15
103.5	143,390		0.0000	1.0000	39.15
104.5	143,390		0.0000	1.0000	39.15
105.5	143,390		0.0000	1.0000	39.15
106.5	132,239	1,763	0.0133	0.9867	39.15
107.5	130,476		0.0000	1.0000	38.62
108.5	128,512		0.0000	1.0000	38.62
109.5	95,314		0.0000	1.0000	38.62
110.5	71,234		0.0000	1.0000	38.62
111.5	71,234		0.0000	1.0000	38.62
112.5					38.62

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,695,701	7,521	0.0011	0.9989	100.00
0.5	6,728,282	20,997	0.0031	0.9969	99.89
1.5	6,711,071	21,499	0.0032	0.9968	99.58
2.5	6,705,441	32,167	0.0048	0.9952	99.26
3.5	6,697,417	30,678	0.0046	0.9954	98.78
4.5	6,696,346	25,064	0.0037	0.9963	98.33
5.5	6,679,161	42,637	0.0064	0.9936	97.96
6.5	6,643,386	18,226	0.0027	0.9973	97.33
7.5	6,622,860	22,925	0.0035	0.9965	97.07
8.5	6,663,450	29,366	0.0044	0.9956	96.73
9.5	6,386,002	41,226	0.0065	0.9935	96.31
10.5	6,277,610	21,963	0.0035	0.9965	95.68
11.5	6,195,084	28,315	0.0046	0.9954	95.35
12.5	6,085,704	13,048	0.0021	0.9979	94.91
13.5	5,950,838	30,191	0.0051	0.9949	94.71
14.5	5,627,402	23,732	0.0042	0.9958	94.23
15.5	5,184,524	19,343	0.0037	0.9963	93.83
16.5	4,867,569	19,038	0.0039	0.9961	93.48
17.5	4,817,989	10,916	0.0023	0.9977	93.12
18.5	4,247,762	9,326	0.0022	0.9978	92.91
19.5	3,504,290	16,589	0.0047	0.9953	92.70
20.5	3,278,681	16,403	0.0050	0.9950	92.26
21.5	3,135,127	13,800	0.0044	0.9956	91.80
22.5	2,774,118	15,137	0.0055	0.9945	91.40
23.5	2,602,110	18,932	0.0073	0.9927	90.90
24.5	2,319,851	13,268	0.0057	0.9943	90.24
25.5	2,154,020	8,705	0.0040	0.9960	89.72
26.5	1,847,345	17,111	0.0093	0.9907	89.36
27.5	1,787,679	13,316	0.0074	0.9926	88.53
28.5	1,361,675	29,698	0.0218	0.9782	87.87
29.5	1,280,133	7,874	0.0062	0.9938	85.95
30.5	1,183,102	17,542	0.0148	0.9852	85.43
31.5	1,082,273	31,415	0.0290	0.9710	84.16
32.5	1,000,530	8,674	0.0087	0.9913	81.72
33.5	967,590	8,968	0.0093	0.9907	81.01
34.5	801,099	7,653	0.0096	0.9904	80.26
35.5	711,527	14,200	0.0200	0.9800	79.49
36.5	682,951	6,679	0.0098	0.9902	77.90
37.5	636,099	3,516	0.0055	0.9945	77.14
38.5	610,373	2,848	0.0047	0.9953	76.72

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	593,032	2,821	0.0048	0.9952	76.36
40.5	452,119	3,562	0.0079	0.9921	75.99
41.5	448,065	4,434	0.0099	0.9901	75.40
42.5	395,421	1,433	0.0036	0.9964	74.65
43.5	382,861	1,066	0.0028	0.9972	74.38
44.5	351,488	1,003	0.0029	0.9971	74.17
45.5	323,771	510	0.0016	0.9984	73.96
46.5	304,030	2,640	0.0087	0.9913	73.84
47.5	269,407	1,398	0.0052	0.9948	73.20
48.5	250,804	770	0.0031	0.9969	72.82
49.5	231,408	1,844	0.0080	0.9920	72.60
50.5	186,727	1,321	0.0071	0.9929	72.02
51.5	169,275	724	0.0043	0.9957	71.51
52.5	148,295	3,050	0.0206	0.9794	71.21
53.5	140,619	798	0.0057	0.9943	69.74
54.5	127,431	614	0.0048	0.9952	69.35
55.5	120,742	73	0.0006	0.9994	69.01
56.5	96,679	517	0.0053	0.9947	68.97
57.5	86,091	875	0.0102	0.9898	68.60
58.5	78,723	183	0.0023	0.9977	67.90
59.5	64,991	115	0.0018	0.9982	67.75
60.5	25,174	165	0.0066	0.9934	67.63
61.5	17,416		0.0000	1.0000	67.18
62.5	8,907	41	0.0046	0.9954	67.18
63.5	3,011		0.0000	1.0000	66.88
64.5	2,992		0.0000	1.0000	66.88
65.5	2,992	348	0.1162	0.8838	66.88
66.5	2,637		0.0000	1.0000	59.10
67.5	2,637	276	0.1046	0.8954	59.10
68.5	2,272	67	0.0295	0.9705	52.92
69.5	1,927	140	0.0726	0.9274	51.36
70.5	1,624	65	0.0399	0.9601	47.63
71.5	1,385	107	0.0771	0.9229	45.73
72.5	1,194		0.0000	1.0000	42.20
73.5	986		0.0000	1.0000	42.20
74.5	871	47	0.0539	0.9461	42.20
75.5	824	43	0.0522	0.9478	39.93
76.5	592		0.0000	1.0000	37.84
77.5	392		0.0000	1.0000	37.84
78.5	262		0.0000	1.0000	37.84

UGI UTILITIES, INC. - GAS DIVISION

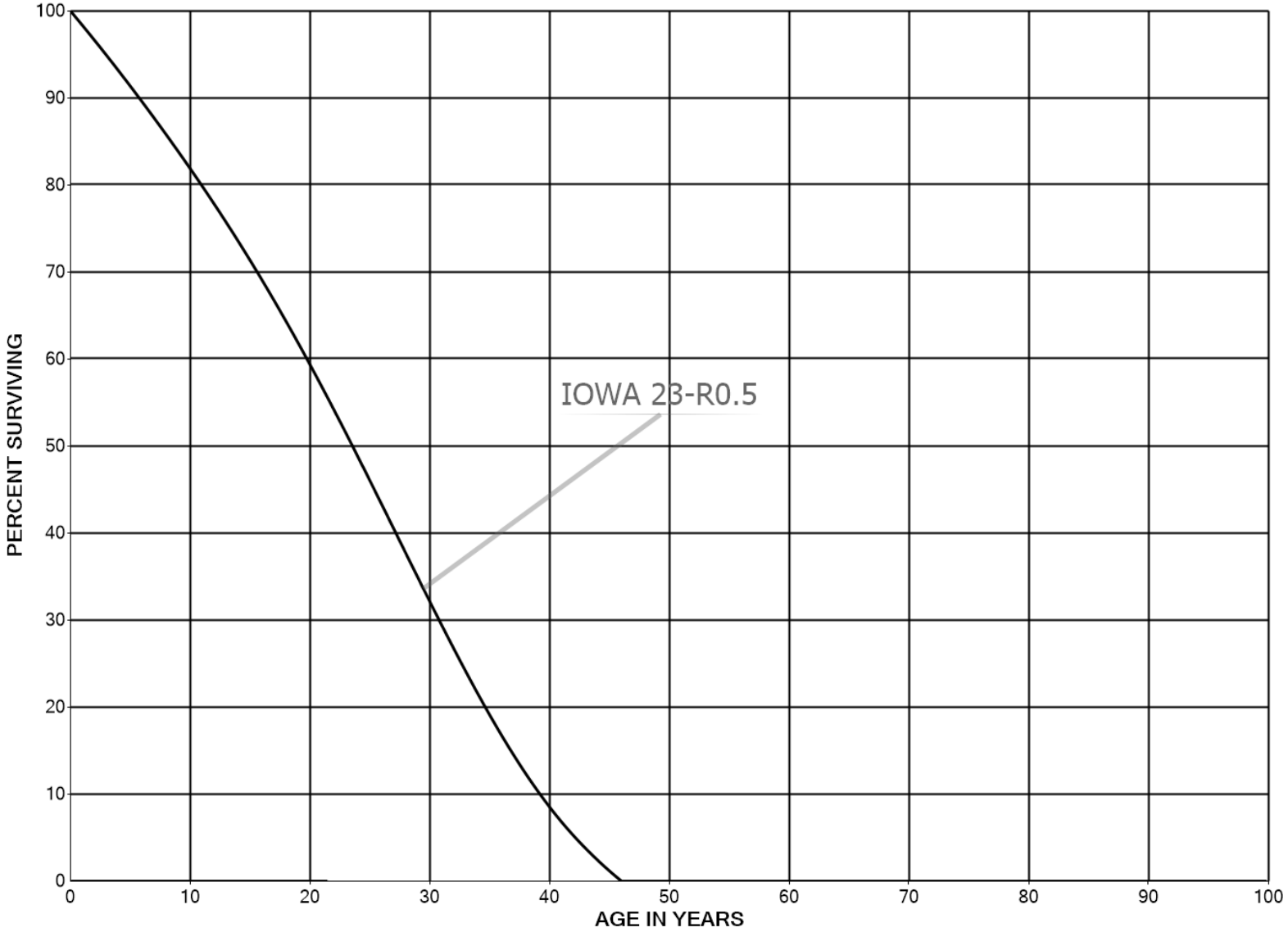
ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

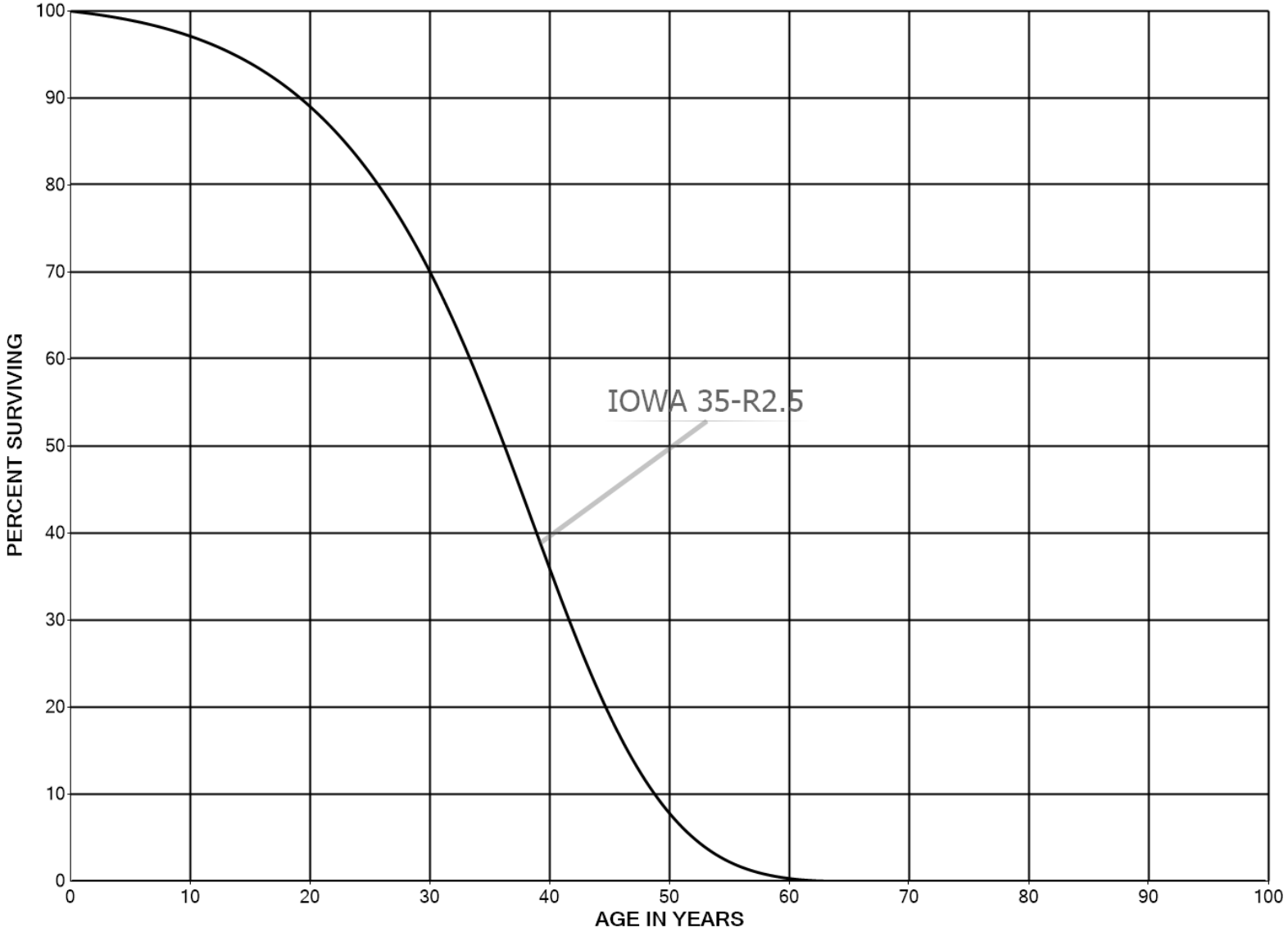
PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	198		0.0000	1.0000	37.84
80.5	198	89	0.4508	0.5492	37.84
81.5	108		0.0000	1.0000	20.78
82.5	108		0.0000	1.0000	20.78
83.5	108		0.0000	1.0000	20.78
84.5	108	65	0.5977	0.4023	20.78
85.5	43		0.0000	1.0000	8.36
86.5	43		0.0000	1.0000	8.36
87.5	43		0.0000	1.0000	8.36
88.5	43		0.0000	1.0000	8.36
89.5					8.36
90.5					
91.5					
92.5					
93.5					
94.5					
95.5	24,615		0.0000		
96.5	24,615		0.0000		
97.5	24,615		0.0000		
98.5	24,615		0.0000		
99.5	24,615		0.0000		
100.5	24,615		0.0000		
101.5	24,615		0.0000		
102.5					

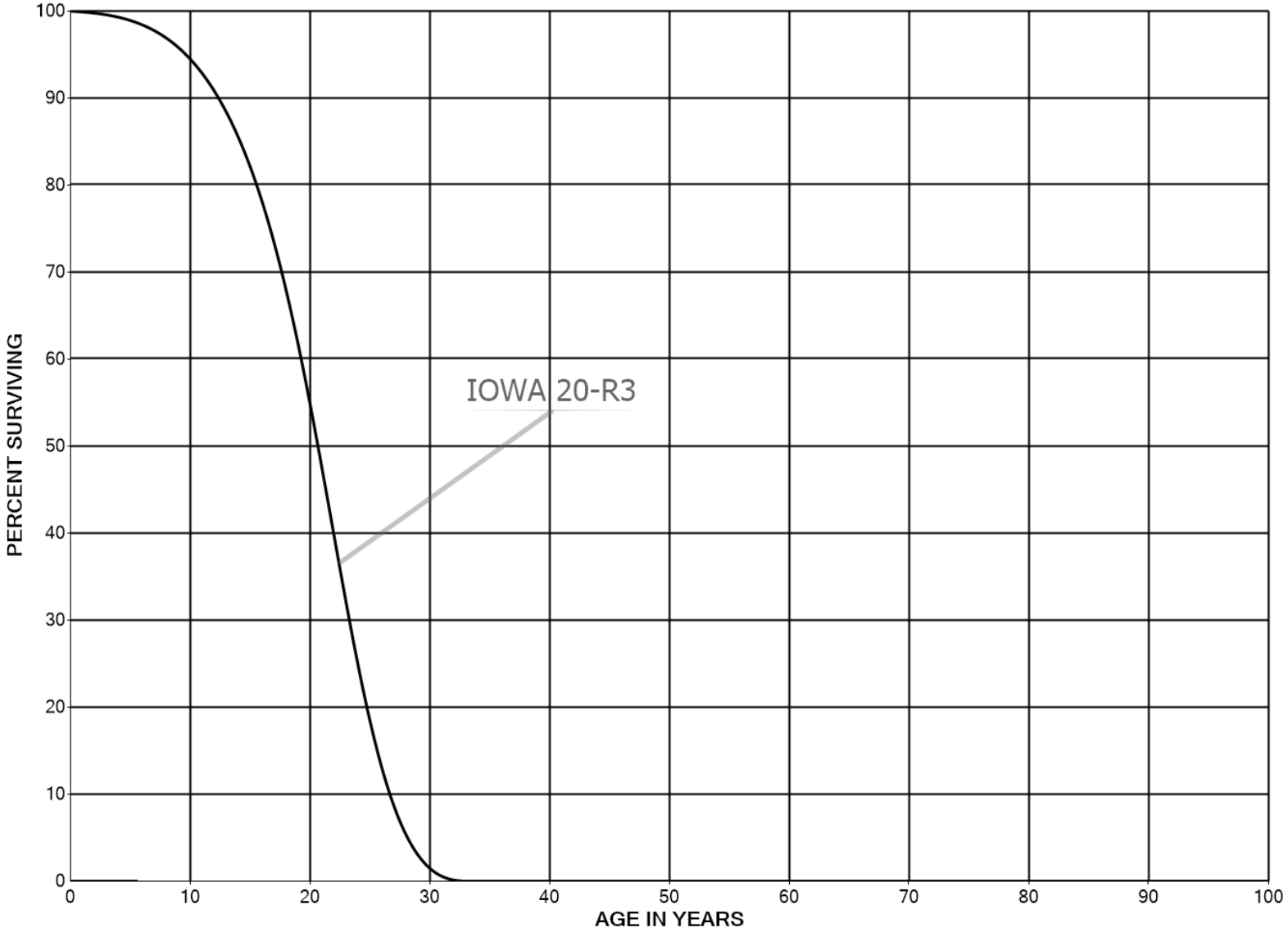
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 370 COMMUNICATION EQUIPMENT
SMOOTH SURVIVOR CURVE



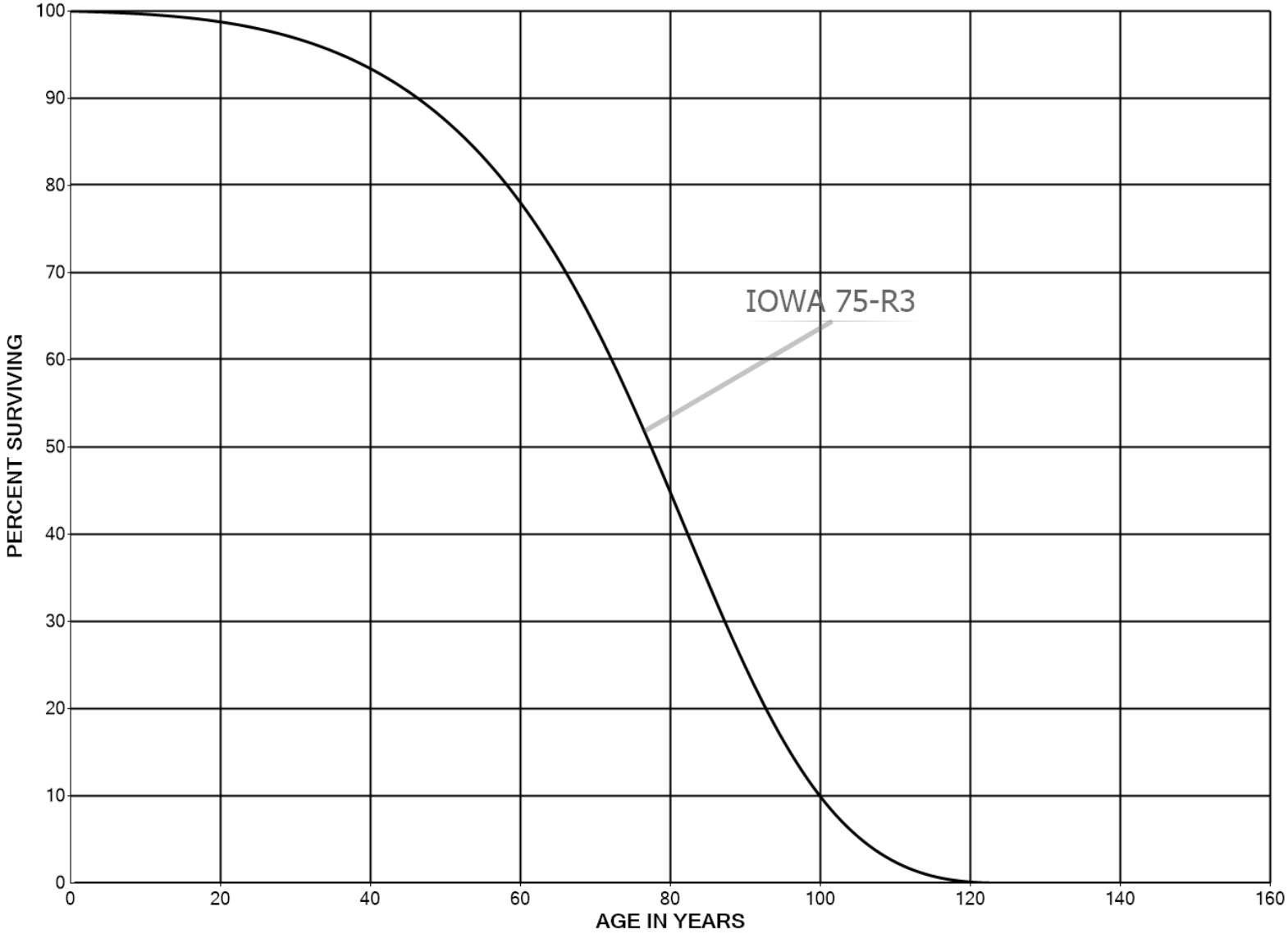
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 371 OTHER EQUIPMENT
SMOOTH SURVIVOR CURVE



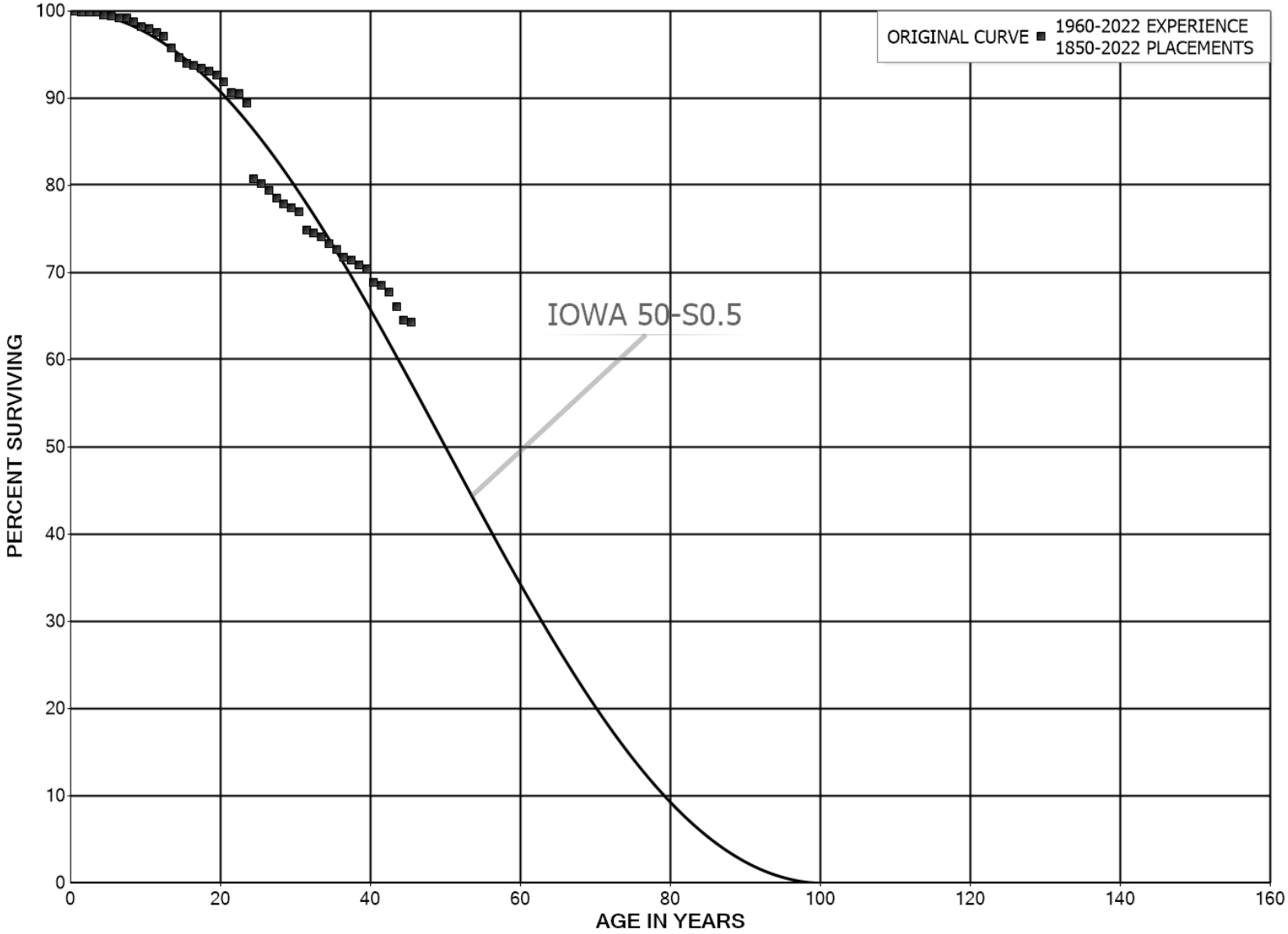
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 371.1 TESTING EQUIPMENT
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 374.2 RIGHTS-OF-WAY
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1850-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,159,861	3,318	0.0006	0.9994	100.00
0.5	5,153,861	3,737	0.0007	0.9993	99.94
1.5	5,113,957		0.0000	1.0000	99.86
2.5	5,119,332	3,306	0.0006	0.9994	99.86
3.5	4,608,645	11,465	0.0025	0.9975	99.80
4.5	4,396,317	9,228	0.0021	0.9979	99.55
5.5	4,208,086	5,692	0.0014	0.9986	99.34
6.5	4,260,024	2,524	0.0006	0.9994	99.21
7.5	4,530,901	20,233	0.0045	0.9955	99.15
8.5	3,041,048	17,351	0.0057	0.9943	98.71
9.5	3,223,490	7,063	0.0022	0.9978	98.14
10.5	3,191,708	12,124	0.0038	0.9962	97.93
11.5	3,042,115	14,072	0.0046	0.9954	97.56
12.5	2,995,406	42,651	0.0142	0.9858	97.10
13.5	3,027,334	36,006	0.0119	0.9881	95.72
14.5	3,007,351	20,955	0.0070	0.9930	94.58
15.5	2,890,575	4,693	0.0016	0.9984	93.92
16.5	2,870,970	12,121	0.0042	0.9958	93.77
17.5	2,866,148	11,151	0.0039	0.9961	93.38
18.5	2,833,620	12,795	0.0045	0.9955	93.01
19.5	2,790,430	22,821	0.0082	0.9918	92.59
20.5	2,683,930	35,302	0.0132	0.9868	91.84
21.5	2,587,336	3,450	0.0013	0.9987	90.63
22.5	2,545,982	30,701	0.0121	0.9879	90.51
23.5	2,469,354	238,693	0.0967	0.9033	89.41
24.5	2,093,708	16,079	0.0077	0.9923	80.77
25.5	2,005,961	18,322	0.0091	0.9909	80.15
26.5	1,919,850	23,063	0.0120	0.9880	79.42
27.5	1,899,168	16,209	0.0085	0.9915	78.47
28.5	1,913,216	9,988	0.0052	0.9948	77.80
29.5	1,971,906	11,358	0.0058	0.9942	77.39
30.5	1,948,499	52,840	0.0271	0.9729	76.94
31.5	1,904,975	8,889	0.0047	0.9953	74.86
32.5	1,884,320	12,311	0.0065	0.9935	74.51
33.5	1,855,987	19,081	0.0103	0.9897	74.02
34.5	1,902,438	17,605	0.0093	0.9907	73.26
35.5	1,963,518	23,412	0.0119	0.9881	72.58
36.5	1,990,420	9,483	0.0048	0.9952	71.72
37.5	1,928,945	15,185	0.0079	0.9921	71.38
38.5	1,801,480	9,877	0.0055	0.9945	70.81

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,794,704	41,526	0.0231	0.9769	70.42
40.5	1,687,745	6,420	0.0038	0.9962	68.80
41.5	1,636,092	19,157	0.0117	0.9883	68.53
42.5	1,601,840	40,431	0.0252	0.9748	67.73
43.5	1,580,551	35,918	0.0227	0.9773	66.02
44.5	1,547,368	6,436	0.0042	0.9958	64.52
45.5	1,549,067	10,423	0.0067	0.9933	64.25
46.5	1,618,271	3,036	0.0019	0.9981	63.82
47.5	1,638,365	4,542	0.0028	0.9972	63.70
48.5	1,633,673	8,858	0.0054	0.9946	63.52
49.5	1,696,363	61,229	0.0361	0.9639	63.18
50.5	1,938,530	24,078	0.0124	0.9876	60.90
51.5	1,971,220	19,791	0.0100	0.9900	60.14
52.5	1,858,955	3,921	0.0021	0.9979	59.54
53.5	1,799,217	127	0.0001	0.9999	59.41
54.5	1,780,337	3,895	0.0022	0.9978	59.41
55.5	1,725,366	20,458	0.0119	0.9881	59.28
56.5	1,668,077	6,580	0.0039	0.9961	58.58
57.5	1,619,182	10,704	0.0066	0.9934	58.35
58.5	1,569,445	9,963	0.0063	0.9937	57.96
59.5	1,485,981	3,498	0.0024	0.9976	57.59
60.5	1,410,413	10,069	0.0071	0.9929	57.46
61.5	1,358,411	9,665	0.0071	0.9929	57.05
62.5	1,306,840	6,758	0.0052	0.9948	56.64
63.5	1,270,952	28,902	0.0227	0.9773	56.35
64.5	1,166,487	6,254	0.0054	0.9946	55.07
65.5	1,046,827	8,035	0.0077	0.9923	54.77
66.5	1,001,774	9,895	0.0099	0.9901	54.35
67.5	984,182	10,621	0.0108	0.9892	53.81
68.5	891,152	28,813	0.0323	0.9677	53.23
69.5	797,927	16,679	0.0209	0.9791	51.51
70.5	759,335	3,267	0.0043	0.9957	50.43
71.5	646,407	498	0.0008	0.9992	50.22
72.5	304,646	18	0.0001	0.9999	50.18
73.5	160,211		0.0000	1.0000	50.18
74.5	141,094		0.0000	1.0000	50.18
75.5	143,837	162	0.0011	0.9989	50.18
76.5	162,679	168	0.0010	0.9990	50.12
77.5	155,697	210	0.0013	0.9987	50.07
78.5	155,006		0.0000	1.0000	50.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	171,582	2,478	0.0144	0.9856	50.00
80.5	168,374	249	0.0015	0.9985	49.28
81.5	168,847	425	0.0025	0.9975	49.21
82.5	168,422		0.0000	1.0000	49.08
83.5	172,774		0.0000	1.0000	49.08
84.5	174,237	256	0.0015	0.9985	49.08
85.5	170,911	860	0.0050	0.9950	49.01
86.5	186,179		0.0000	1.0000	48.76
87.5	190,854		0.0000	1.0000	48.76
88.5	190,561		0.0000	1.0000	48.76
89.5	184,868		0.0000	1.0000	48.76
90.5	184,444	882	0.0048	0.9952	48.76
91.5	182,637		0.0000	1.0000	48.53
92.5	175,636		0.0000	1.0000	48.53
93.5	169,173	27	0.0002	0.9998	48.53
94.5	168,218		0.0000	1.0000	48.52
95.5	140,218	10,856	0.0774	0.9226	48.52
96.5	127,712	98	0.0008	0.9992	44.77
97.5	118,063		0.0000	1.0000	44.73
98.5	69,542		0.0000	1.0000	44.73
99.5	69,097		0.0000	1.0000	44.73
100.5	63,410		0.0000	1.0000	44.73
101.5	44,573		0.0000	1.0000	44.73
102.5	42,200		0.0000	1.0000	44.73
103.5	47,717		0.0000	1.0000	44.73
104.5	42,973		0.0000	1.0000	44.73
105.5	40,620		0.0000	1.0000	44.73
106.5	40,993		0.0000	1.0000	44.73
107.5	39,989	1,000	0.0250	0.9750	44.73
108.5	38,942	9,167	0.2354	0.7646	43.61
109.5	33,373		0.0000	1.0000	33.35
110.5	33,016	158	0.0048	0.9952	33.35
111.5	35,719	67	0.0019	0.9981	33.19
112.5	27,414		0.0000	1.0000	33.13
113.5	25,979		0.0000	1.0000	33.13
114.5	22,197		0.0000	1.0000	33.13
115.5	22,197	975	0.0439	0.9561	33.13
116.5	19,087	821	0.0430	0.9570	31.67
117.5	16,944	2,117	0.1249	0.8751	30.31
118.5	14,827		0.0000	1.0000	26.52

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	14,827		0.0000	1.0000	26.52
120.5	10,222		0.0000	1.0000	26.52
121.5	10,222		0.0000	1.0000	26.52
122.5	9,663	508	0.0526	0.9474	26.52
123.5	6,579		0.0000	1.0000	25.13
124.5	6,419		0.0000	1.0000	25.13
125.5	6,240		0.0000	1.0000	25.13
126.5	5,540		0.0000	1.0000	25.13
127.5	5,540		0.0000	1.0000	25.13
128.5	5,540		0.0000	1.0000	25.13
129.5	5,540		0.0000	1.0000	25.13
130.5	5,540		0.0000	1.0000	25.13
131.5	5,540		0.0000	1.0000	25.13
132.5	5,613		0.0000	1.0000	25.13
133.5	5,613		0.0000	1.0000	25.13
134.5	1,420		0.0000	1.0000	25.13
135.5	1,420		0.0000	1.0000	25.13
136.5	1,420		0.0000	1.0000	25.13
137.5	1,420		0.0000	1.0000	25.13
138.5	1,420		0.0000	1.0000	25.13
139.5	1,420		0.0000	1.0000	25.13
140.5	1,420		0.0000	1.0000	25.13
141.5	1,420		0.0000	1.0000	25.13
142.5	1,420		0.0000	1.0000	25.13
143.5	1,420		0.0000	1.0000	25.13
144.5	1,420		0.0000	1.0000	25.13
145.5	1,420		0.0000	1.0000	25.13
146.5	1,420		0.0000	1.0000	25.13
147.5	1,420		0.0000	1.0000	25.13
148.5	1,420		0.0000	1.0000	25.13
149.5	1,420		0.0000	1.0000	25.13
150.5	2,851		0.0000	1.0000	25.13
151.5	2,851		0.0000	1.0000	25.13
152.5	2,851		0.0000	1.0000	25.13
153.5	2,851		0.0000	1.0000	25.13
154.5	2,779		0.0000	1.0000	25.13
155.5	2,779		0.0000	1.0000	25.13
156.5	2,779		0.0000	1.0000	25.13
157.5	2,779		0.0000	1.0000	25.13
158.5	2,779		0.0000	1.0000	25.13

UGI UTILITIES, INC. - GAS DIVISION

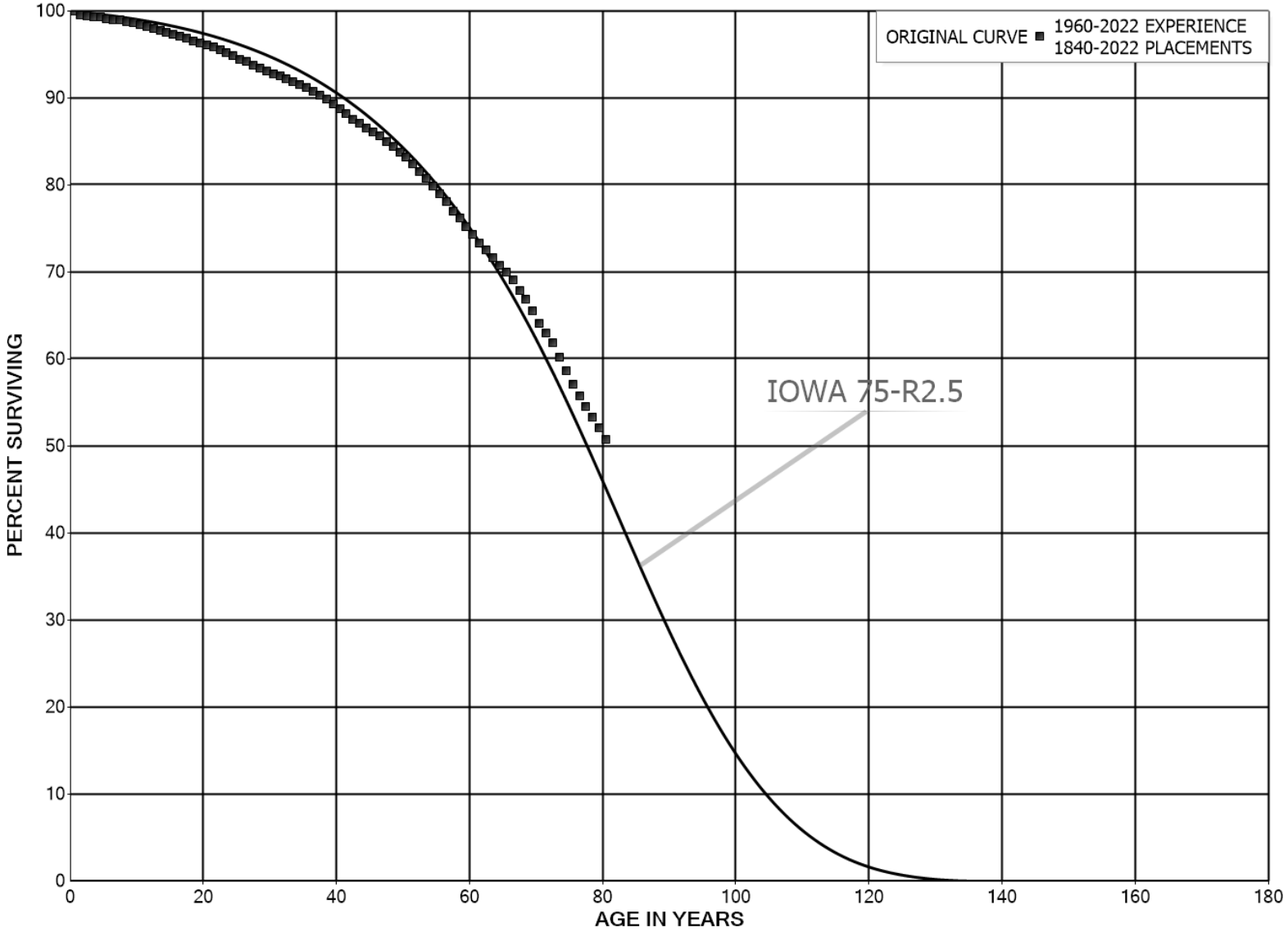
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	2,779		0.0000	1.0000	25.13
160.5	2,779		0.0000	1.0000	25.13
161.5	2,779		0.0000	1.0000	25.13
162.5	2,779		0.0000	1.0000	25.13
163.5	2,795		0.0000	1.0000	25.13
164.5	2,795		0.0000	1.0000	25.13
165.5	2,795		0.0000	1.0000	25.13
166.5	2,795		0.0000	1.0000	25.13
167.5	2,795		0.0000	1.0000	25.13
168.5	2,795		0.0000	1.0000	25.13
169.5	2,795		0.0000	1.0000	25.13
170.5	2,795		0.0000	1.0000	25.13
171.5	2,795		0.0000	1.0000	25.13
172.5					25.13

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.1 MAINS - PRIMARILY STEEL
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	688,133,647	50,396	0.0001	0.9999	100.00
0.5	661,745,657	3,314,891	0.0050	0.9950	99.99
1.5	626,243,320	562,221	0.0009	0.9991	99.49
2.5	598,356,983	469,303	0.0008	0.9992	99.40
3.5	578,965,969	516,940	0.0009	0.9991	99.32
4.5	495,539,907	754,209	0.0015	0.9985	99.24
5.5	458,607,452	479,476	0.0010	0.9990	99.08
6.5	426,361,944	300,859	0.0007	0.9993	98.98
7.5	400,158,489	815,706	0.0020	0.9980	98.91
8.5	378,999,572	519,083	0.0014	0.9986	98.71
9.5	371,499,252	749,339	0.0020	0.9980	98.57
10.5	366,193,197	903,118	0.0025	0.9975	98.38
11.5	360,354,118	526,016	0.0015	0.9985	98.13
12.5	354,278,497	822,142	0.0023	0.9977	97.99
13.5	347,924,229	737,784	0.0021	0.9979	97.76
14.5	342,045,570	870,962	0.0025	0.9975	97.56
15.5	338,038,222	784,673	0.0023	0.9977	97.31
16.5	330,764,970	991,478	0.0030	0.9970	97.08
17.5	319,669,291	838,188	0.0026	0.9974	96.79
18.5	311,055,503	775,450	0.0025	0.9975	96.54
19.5	305,010,456	888,491	0.0029	0.9971	96.30
20.5	296,660,652	586,252	0.0020	0.9980	96.01
21.5	287,750,237	972,731	0.0034	0.9966	95.83
22.5	272,756,651	947,508	0.0035	0.9965	95.50
23.5	270,011,234	1,039,566	0.0039	0.9961	95.17
24.5	262,225,797	1,016,118	0.0039	0.9961	94.80
25.5	250,821,558	815,453	0.0033	0.9967	94.44
26.5	235,792,925	897,307	0.0038	0.9962	94.13
27.5	228,788,978	857,543	0.0037	0.9963	93.77
28.5	226,352,491	897,908	0.0040	0.9960	93.42
29.5	223,927,556	655,250	0.0029	0.9971	93.05
30.5	217,543,101	681,769	0.0031	0.9969	92.78
31.5	213,151,385	672,572	0.0032	0.9968	92.49
32.5	208,453,344	773,495	0.0037	0.9963	92.19
33.5	203,250,443	783,115	0.0039	0.9961	91.85
34.5	196,821,943	722,343	0.0037	0.9963	91.50
35.5	192,872,741	830,296	0.0043	0.9957	91.16
36.5	185,531,002	975,722	0.0053	0.9947	90.77
37.5	179,659,426	973,750	0.0054	0.9946	90.29
38.5	174,614,878	983,653	0.0056	0.9944	89.80

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	171,011,212	1,097,272	0.0064	0.9936	89.30
40.5	158,074,998	960,209	0.0061	0.9939	88.72
41.5	147,574,374	1,120,307	0.0076	0.9924	88.18
42.5	136,221,509	690,568	0.0051	0.9949	87.52
43.5	130,145,731	788,512	0.0061	0.9939	87.07
44.5	126,297,233	632,300	0.0050	0.9950	86.54
45.5	122,222,460	740,775	0.0061	0.9939	86.11
46.5	118,998,228	882,261	0.0074	0.9926	85.59
47.5	115,311,420	788,113	0.0068	0.9932	84.95
48.5	110,706,933	815,826	0.0074	0.9926	84.37
49.5	105,644,033	796,608	0.0075	0.9925	83.75
50.5	98,350,454	885,923	0.0090	0.9910	83.12
51.5	92,017,811	924,687	0.0100	0.9900	82.37
52.5	85,173,944	884,070	0.0104	0.9896	81.54
53.5	76,991,643	778,990	0.0101	0.9899	80.70
54.5	68,948,946	786,503	0.0114	0.9886	79.88
55.5	62,512,601	719,769	0.0115	0.9885	78.97
56.5	56,117,970	768,984	0.0137	0.9863	78.06
57.5	49,871,218	528,190	0.0106	0.9894	76.99
58.5	43,635,930	572,822	0.0131	0.9869	76.18
59.5	38,576,060	454,912	0.0118	0.9882	75.18
60.5	35,081,316	473,978	0.0135	0.9865	74.29
61.5	31,504,395	334,720	0.0106	0.9894	73.29
62.5	27,665,795	333,308	0.0120	0.9880	72.51
63.5	24,419,455	295,805	0.0121	0.9879	71.63
64.5	20,946,805	243,169	0.0116	0.9884	70.77
65.5	17,570,535	210,302	0.0120	0.9880	69.94
66.5	14,930,599	280,204	0.0188	0.9812	69.11
67.5	13,396,662	184,698	0.0138	0.9862	67.81
68.5	11,827,147	240,026	0.0203	0.9797	66.87
69.5	10,492,637	231,278	0.0220	0.9780	65.52
70.5	9,487,554	167,191	0.0176	0.9824	64.07
71.5	8,971,276	163,579	0.0182	0.9818	62.94
72.5	7,187,219	182,260	0.0254	0.9746	61.80
73.5	6,764,285	178,562	0.0264	0.9736	60.23
74.5	6,468,743	175,833	0.0272	0.9728	58.64
75.5	6,245,503	140,048	0.0224	0.9776	57.05
76.5	5,660,517	129,359	0.0229	0.9771	55.77
77.5	5,562,716	122,583	0.0220	0.9780	54.49
78.5	5,441,893	123,349	0.0227	0.9773	53.29

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	5,332,294	140,234	0.0263	0.9737	52.08
80.5	5,183,217	142,502	0.0275	0.9725	50.71
81.5	4,998,403	151,516	0.0303	0.9697	49.32
82.5	4,826,663	143,447	0.0297	0.9703	47.82
83.5	4,649,833	168,457	0.0362	0.9638	46.40
84.5	4,485,932	167,212	0.0373	0.9627	44.72
85.5	4,315,820	164,108	0.0380	0.9620	43.05
86.5	4,152,683	200,293	0.0482	0.9518	41.42
87.5	3,955,901	159,268	0.0403	0.9597	39.42
88.5	3,783,700	143,430	0.0379	0.9621	37.83
89.5	3,635,363	161,092	0.0443	0.9557	36.40
90.5	3,416,513	172,911	0.0506	0.9494	34.79
91.5	2,856,764	92,562	0.0324	0.9676	33.03
92.5	2,373,070	109,704	0.0462	0.9538	31.96
93.5	2,123,008	107,205	0.0505	0.9495	30.48
94.5	1,858,500	76,526	0.0412	0.9588	28.94
95.5	1,715,271	72,240	0.0421	0.9579	27.75
96.5	1,306,417	46,106	0.0353	0.9647	26.58
97.5	1,193,695	45,133	0.0378	0.9622	25.64
98.5	984,467	36,980	0.0376	0.9624	24.67
99.5	919,263	45,916	0.0499	0.9501	23.74
100.5	828,760	46,065	0.0556	0.9444	22.56
101.5	744,735	40,542	0.0544	0.9456	21.30
102.5	700,985	42,507	0.0606	0.9394	20.14
103.5	657,838	43,156	0.0656	0.9344	18.92
104.5	618,296	40,738	0.0659	0.9341	17.68
105.5	582,128	37,312	0.0641	0.9359	16.52
106.5	551,838	39,438	0.0715	0.9285	15.46
107.5	515,054	26,854	0.0521	0.9479	14.35
108.5	492,071	28,791	0.0585	0.9415	13.61
109.5	462,940	30,540	0.0660	0.9340	12.81
110.5	431,972	29,384	0.0680	0.9320	11.96
111.5	405,788	32,593	0.0803	0.9197	11.15
112.5	371,029	26,541	0.0715	0.9285	10.25
113.5	344,146	16,457	0.0478	0.9522	9.52
114.5	304,069	20,193	0.0664	0.9336	9.07
115.5	272,663	18,553	0.0680	0.9320	8.46
116.5	248,662	22,409	0.0901	0.9099	7.89
117.5	225,530	10,071	0.0447	0.9553	7.18
118.5	214,903	11,445	0.0533	0.9467	6.86

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	202,560	10,972	0.0542	0.9458	6.49
120.5	191,557	15,024	0.0784	0.9216	6.14
121.5	173,921	11,984	0.0689	0.9311	5.66
122.5	161,929	15,170	0.0937	0.9063	5.27
123.5	146,767	9,211	0.0628	0.9372	4.77
124.5	137,560	5,491	0.0399	0.9601	4.48
125.5	132,277	6,001	0.0454	0.9546	4.30
126.5	126,428	7,867	0.0622	0.9378	4.10
127.5	118,411	6,844	0.0578	0.9422	3.85
128.5	111,915	7,836	0.0700	0.9300	3.62
129.5	103,729	6,166	0.0594	0.9406	3.37
130.5	98,244	5,200	0.0529	0.9471	3.17
131.5	93,045	3,238	0.0348	0.9652	3.00
132.5	89,806	4,102	0.0457	0.9543	2.90
133.5	85,705	4,275	0.0499	0.9501	2.77
134.5	81,430	5,217	0.0641	0.9359	2.63
135.5	76,028	3,138	0.0413	0.9587	2.46
136.5	72,876	7,774	0.1067	0.8933	2.36
137.5	65,102	5,166	0.0793	0.9207	2.11
138.5	59,936	4,507	0.0752	0.9248	1.94
139.5	55,444	3,173	0.0572	0.9428	1.79
140.5	52,271	8,832	0.1690	0.8310	1.69
141.5	43,440	2,997	0.0690	0.9310	1.40
142.5	40,442	11,480	0.2839	0.7161	1.31
143.5	28,909	7,782	0.2692	0.7308	0.94
144.5	21,127	2,140	0.1013	0.8987	0.68
145.5	19,146	1,903	0.0994	0.9006	0.62
146.5	17,243	2,525	0.1464	0.8536	0.55
147.5	14,719	1,435	0.0975	0.9025	0.47
148.5	13,283	14,594	1.0987	0.0987-	0.43
149.5	12,359	392	0.0317		
150.5	11,810	113	0.0096		
151.5	11,696	1,042	0.0891		
152.5	10,654	1,224	0.1149		
153.5	9,430	1,024	0.1086		
154.5	8,406	1,120	0.1332		
155.5	7,286	410	0.0562		
156.5	6,877	1,399	0.2034		
157.5	5,478	512	0.0935		
158.5	4,966	1,175	0.2366		

UGI UTILITIES, INC. - GAS DIVISION

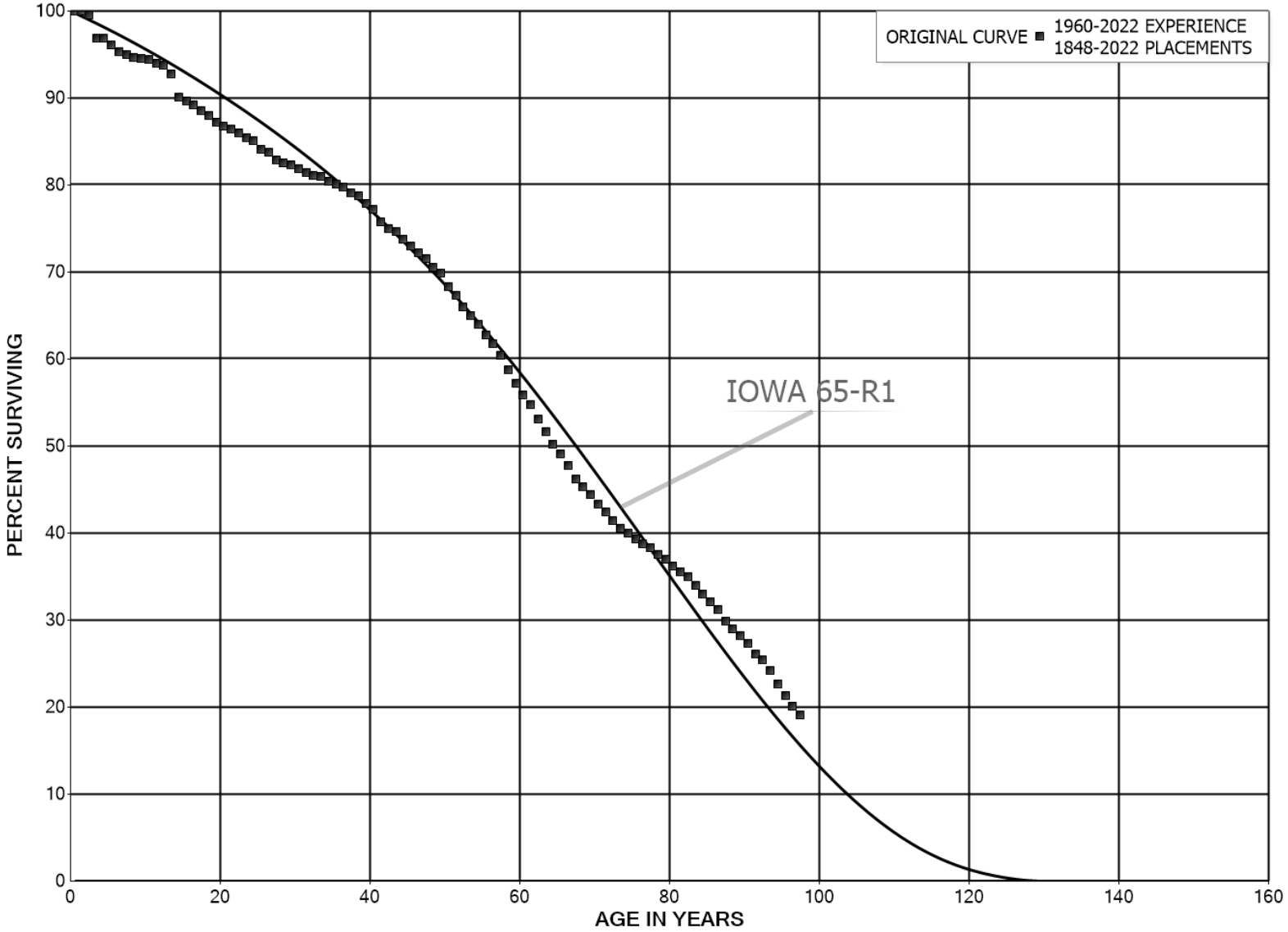
ACCOUNT 376.1 MAINS - PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	3,791	345	0.0909		
160.5	3,446	1,778	0.5160		
161.5	1,668	1,149	0.6888		
162.5	519	389	0.7488		
163.5	130	46	0.3492		
164.5	85	85	1.0000		
165.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.2 MAINS - CAST IRON
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1848-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	197,612		0.0000	1.0000	100.00
0.5	417,677		0.0000	1.0000	100.00
1.5	687,128	3,376	0.0049	0.9951	100.00
2.5	1,000,259	26,728	0.0267	0.9733	99.51
3.5	1,244,584	525	0.0004	0.9996	96.85
4.5	1,450,530	11,504	0.0079	0.9921	96.81
5.5	1,661,968	12,910	0.0078	0.9922	96.04
6.5	1,921,892	7,588	0.0039	0.9961	95.30
7.5	2,224,762	6,671	0.0030	0.9970	94.92
8.5	2,419,075	1,972	0.0008	0.9992	94.63
9.5	2,627,538	3,127	0.0012	0.9988	94.56
10.5	2,787,538	14,625	0.0052	0.9948	94.44
11.5	2,902,073	8,394	0.0029	0.9971	93.95
12.5	3,013,884	31,594	0.0105	0.9895	93.68
13.5	3,044,592	86,763	0.0285	0.9715	92.70
14.5	2,984,170	13,462	0.0045	0.9955	90.05
15.5	2,988,640	15,246	0.0051	0.9949	89.65
16.5	3,036,914	21,862	0.0072	0.9928	89.19
17.5	3,046,806	19,803	0.0065	0.9935	88.55
18.5	3,111,947	26,985	0.0087	0.9913	87.97
19.5	3,125,882	18,325	0.0059	0.9941	87.21
20.5	3,150,974	9,333	0.0030	0.9970	86.70
21.5	3,178,999	18,431	0.0058	0.9942	86.44
22.5	3,188,335	21,917	0.0069	0.9931	85.94
23.5	3,191,613	12,031	0.0038	0.9962	85.35
24.5	3,190,805	34,170	0.0107	0.9893	85.03
25.5	3,164,937	16,511	0.0052	0.9948	84.12
26.5	3,187,749	33,572	0.0105	0.9895	83.68
27.5	3,180,062	9,579	0.0030	0.9970	82.80
28.5	3,220,033	10,891	0.0034	0.9966	82.55
29.5	3,348,822	16,633	0.0050	0.9950	82.27
30.5	3,540,876	18,628	0.0053	0.9947	81.86
31.5	3,721,266	15,311	0.0041	0.9959	81.43
32.5	3,925,305	8,873	0.0023	0.9977	81.09
33.5	4,206,408	26,216	0.0062	0.9938	80.91
34.5	4,483,684	19,307	0.0043	0.9957	80.41
35.5	4,987,617	18,656	0.0037	0.9963	80.06
36.5	5,309,238	43,775	0.0082	0.9918	79.76
37.5	5,411,838	29,004	0.0054	0.9946	79.10
38.5	5,460,066	56,405	0.0103	0.9897	78.68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,492,149	45,417	0.0083	0.9917	77.87
40.5	5,506,358	106,710	0.0194	0.9806	77.22
41.5	5,436,602	51,809	0.0095	0.9905	75.73
42.5	5,459,514	26,553	0.0049	0.9951	75.00
43.5	5,528,545	71,600	0.0130	0.9870	74.64
44.5	5,533,831	55,266	0.0100	0.9900	73.67
45.5	5,511,782	59,045	0.0107	0.9893	72.94
46.5	5,486,240	49,771	0.0091	0.9909	72.16
47.5	5,511,343	78,203	0.0142	0.9858	71.50
48.5	5,500,776	54,614	0.0099	0.9901	70.49
49.5	5,505,845	121,699	0.0221	0.9779	69.79
50.5	5,438,953	73,442	0.0135	0.9865	68.24
51.5	5,423,954	107,777	0.0199	0.9801	67.32
52.5	5,364,717	88,984	0.0166	0.9834	65.99
53.5	5,355,495	75,165	0.0140	0.9860	64.89
54.5	5,347,347	102,717	0.0192	0.9808	63.98
55.5	5,311,456	90,862	0.0171	0.9829	62.75
56.5	5,272,450	109,736	0.0208	0.9792	61.68
57.5	5,201,028	142,549	0.0274	0.9726	60.39
58.5	5,110,934	138,771	0.0272	0.9728	58.74
59.5	4,997,875	118,155	0.0236	0.9764	57.14
60.5	4,932,391	95,814	0.0194	0.9806	55.79
61.5	4,854,309	146,952	0.0303	0.9697	54.71
62.5	4,715,231	129,392	0.0274	0.9726	53.05
63.5	4,530,129	128,018	0.0283	0.9717	51.60
64.5	4,364,518	98,265	0.0225	0.9775	50.14
65.5	4,199,703	112,616	0.0268	0.9732	49.01
66.5	4,046,052	130,080	0.0321	0.9679	47.70
67.5	3,857,659	71,743	0.0186	0.9814	46.16
68.5	3,755,304	78,905	0.0210	0.9790	45.30
69.5	3,611,479	85,926	0.0238	0.9762	44.35
70.5	3,390,981	72,738	0.0215	0.9785	43.30
71.5	3,297,539	71,541	0.0217	0.9783	42.37
72.5	3,197,337	69,138	0.0216	0.9784	41.45
73.5	3,127,483	49,196	0.0157	0.9843	40.55
74.5	3,060,344	44,268	0.0145	0.9855	39.91
75.5	3,010,005	44,441	0.0148	0.9852	39.34
76.5	2,973,360	39,564	0.0133	0.9867	38.76
77.5	2,948,440	52,503	0.0178	0.9822	38.24
78.5	2,903,390	42,759	0.0147	0.9853	37.56

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,878,413	64,853	0.0225	0.9775	37.01
80.5	2,823,005	51,640	0.0183	0.9817	36.17
81.5	2,760,818	48,090	0.0174	0.9826	35.51
82.5	2,713,213	71,425	0.0263	0.9737	34.89
83.5	2,644,801	80,504	0.0304	0.9696	33.97
84.5	2,578,588	65,997	0.0256	0.9744	32.94
85.5	2,517,139	70,465	0.0280	0.9720	32.10
86.5	2,469,078	112,221	0.0455	0.9545	31.20
87.5	2,371,645	67,317	0.0284	0.9716	29.78
88.5	2,313,980	57,210	0.0247	0.9753	28.94
89.5	2,270,990	70,853	0.0312	0.9688	28.22
90.5	2,204,980	101,568	0.0461	0.9539	27.34
91.5	2,115,353	55,561	0.0263	0.9737	26.08
92.5	2,051,253	95,987	0.0468	0.9532	25.40
93.5	1,902,371	124,387	0.0654	0.9346	24.21
94.5	1,753,394	103,860	0.0592	0.9408	22.62
95.5	1,613,307	96,414	0.0598	0.9402	21.28
96.5	1,465,119	68,321	0.0466	0.9534	20.01
97.5	1,370,717	68,876	0.0502	0.9498	19.08
98.5	1,207,630	31,846	0.0264	0.9736	18.12
99.5	1,155,922	40,810	0.0353	0.9647	17.64
100.5	1,071,541	54,631	0.0510	0.9490	17.02
101.5	1,008,712	47,552	0.0471	0.9529	16.15
102.5	949,456	35,603	0.0375	0.9625	15.39
103.5	894,409	36,717	0.0411	0.9589	14.81
104.5	853,295	31,483	0.0369	0.9631	14.20
105.5	819,810	26,623	0.0325	0.9675	13.68
106.5	786,179	40,519	0.0515	0.9485	13.24
107.5	733,833	40,839	0.0557	0.9443	12.55
108.5	691,293	38,401	0.0556	0.9444	11.86
109.5	654,530	38,975	0.0595	0.9405	11.20
110.5	596,487	31,828	0.0534	0.9466	10.53
111.5	548,209	37,596	0.0686	0.9314	9.97
112.5	499,395	38,911	0.0779	0.9221	9.28
113.5	455,602	25,856	0.0568	0.9432	8.56
114.5	421,014	24,478	0.0581	0.9419	8.08
115.5	393,865	26,885	0.0683	0.9317	7.61
116.5	361,143	25,651	0.0710	0.9290	7.09
117.5	332,115	12,599	0.0379	0.9621	6.58
118.5	315,788	20,904	0.0662	0.9338	6.33

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	292,901	12,838	0.0438	0.9562	5.91
120.5	277,877	16,613	0.0598	0.9402	5.66
121.5	257,179	24,870	0.0967	0.9033	5.32
122.5	232,301	20,353	0.0876	0.9124	4.80
123.5	195,512	9,659	0.0494	0.9506	4.38
124.5	185,263	6,195	0.0334	0.9666	4.17
125.5	177,913	6,464	0.0363	0.9637	4.03
126.5	169,876	9,694	0.0571	0.9429	3.88
127.5	158,249	8,797	0.0556	0.9444	3.66
128.5	149,255	8,128	0.0545	0.9455	3.46
129.5	141,027	6,793	0.0482	0.9518	3.27
130.5	134,915	7,544	0.0559	0.9441	3.11
131.5	126,926	4,624	0.0364	0.9636	2.94
132.5	120,705	5,437	0.0450	0.9550	2.83
133.5	113,991	5,529	0.0485	0.9515	2.70
134.5	108,323	8,890	0.0821	0.9179	2.57
135.5	98,872	3,138	0.0317	0.9683	2.36
136.5	95,169	10,353	0.1088	0.8912	2.28
137.5	84,701	5,166	0.0610	0.9390	2.04
138.5	78,565	5,505	0.0701	0.9299	1.91
139.5	73,041	4,144	0.0567	0.9433	1.78
140.5	68,811	8,974	0.1304	0.8696	1.68
141.5	58,912	4,112	0.0698	0.9302	1.46
142.5	54,800	11,480	0.2095	0.7905	1.36
143.5	43,320	8,999	0.2077	0.7923	1.07
144.5	34,321	3,410	0.0993	0.9007	0.85
145.5	31,118	3,348	0.1076	0.8924	0.77
146.5	27,752	5,963	0.2149	0.7851	0.68
147.5	21,445	2,668	0.1244	0.8756	0.54
148.5	18,697	1,334	0.0713	0.9287	0.47
149.5	17,361	2,824	0.1627	0.8373	0.44
150.5	14,308	341	0.0238	0.9762	0.37
151.5	13,967	1,077	0.0771	0.9229	0.36
152.5	12,890	1,224	0.0949	0.9051	0.33
153.5	11,666	1,024	0.0878	0.9122	0.30
154.5	10,642	1,235	0.1161	0.8839	0.27
155.5	9,407	410	0.0435	0.9565	0.24
156.5	8,998	1,399	0.1554	0.8446	0.23
157.5	7,599	549	0.0722	0.9278	0.19
158.5	7,050	1,175	0.1666	0.8334	0.18

UGI UTILITIES, INC. - GAS DIVISION

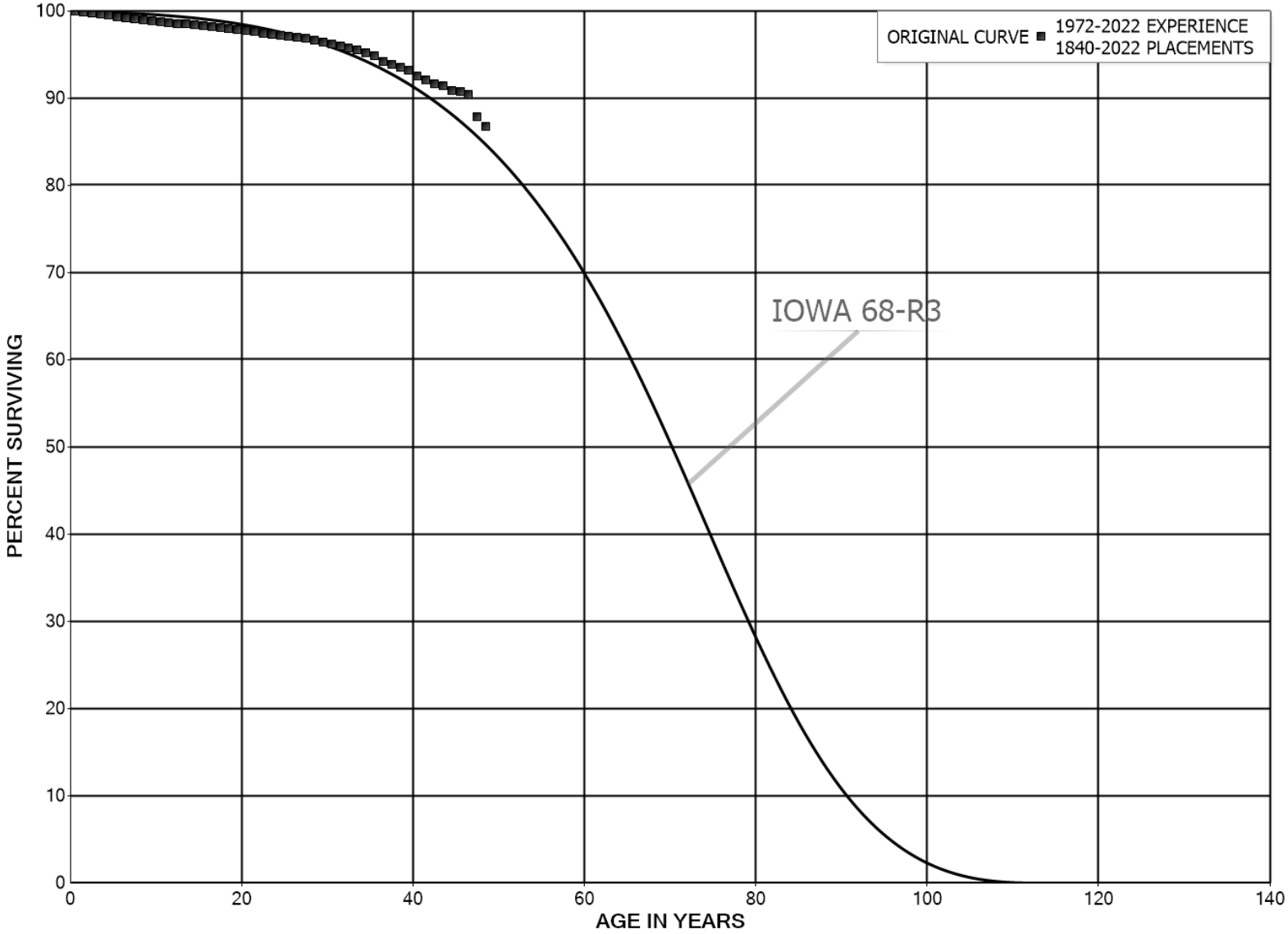
ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	5,875	2,429	0.4135	0.5865	0.15
160.5	3,446	1,778	0.5160	0.4840	0.09
161.5	1,668	1,149	0.6888	0.3112	0.04
162.5	519	389	0.7488	0.2512	0.01
163.5	130	46	0.3492	0.6508	0.00
164.5	85	85	1.0000		0.00
165.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.3 MAINS - PLASTIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1972-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,473,220,494	154,882	0.0001	0.9999	100.00
0.5	1,351,584,904	1,468,058	0.0011	0.9989	99.99
1.5	1,222,862,470	1,979,246	0.0016	0.9984	99.88
2.5	1,134,339,882	1,625,235	0.0014	0.9986	99.72
3.5	1,024,080,158	1,071,535	0.0010	0.9990	99.58
4.5	931,364,780	1,673,514	0.0018	0.9982	99.47
5.5	856,432,220	759,993	0.0009	0.9991	99.29
6.5	780,843,309	1,319,323	0.0017	0.9983	99.21
7.5	717,717,339	787,762	0.0011	0.9989	99.04
8.5	668,452,329	509,857	0.0008	0.9992	98.93
9.5	626,793,938	639,828	0.0010	0.9990	98.85
10.5	589,377,846	538,091	0.0009	0.9991	98.75
11.5	559,840,985	599,801	0.0011	0.9989	98.66
12.5	536,923,742	486,356	0.0009	0.9991	98.56
13.5	515,011,610	413,071	0.0008	0.9992	98.47
14.5	493,164,412	496,581	0.0010	0.9990	98.39
15.5	467,501,389	529,517	0.0011	0.9989	98.29
16.5	441,714,695	508,374	0.0012	0.9988	98.18
17.5	415,481,044	500,379	0.0012	0.9988	98.07
18.5	388,442,754	371,084	0.0010	0.9990	97.95
19.5	365,091,660	418,406	0.0011	0.9989	97.85
20.5	347,236,905	533,611	0.0015	0.9985	97.74
21.5	326,052,674	513,076	0.0016	0.9984	97.59
22.5	305,628,380	336,890	0.0011	0.9989	97.44
23.5	286,153,582	432,972	0.0015	0.9985	97.33
24.5	262,545,095	435,745	0.0017	0.9983	97.18
25.5	233,051,567	281,048	0.0012	0.9988	97.02
26.5	212,105,200	237,606	0.0011	0.9989	96.90
27.5	186,860,052	423,909	0.0023	0.9977	96.80
28.5	168,068,103	267,902	0.0016	0.9984	96.58
29.5	156,452,620	340,640	0.0022	0.9978	96.42
30.5	144,048,411	365,416	0.0025	0.9975	96.21
31.5	129,571,666	300,108	0.0023	0.9977	95.97
32.5	107,032,768	257,399	0.0024	0.9976	95.75
33.5	86,841,343	278,857	0.0032	0.9968	95.52
34.5	67,616,206	257,176	0.0038	0.9962	95.21
35.5	54,922,056	396,027	0.0072	0.9928	94.85
36.5	46,124,832	179,858	0.0039	0.9961	94.16
37.5	39,460,884	104,185	0.0026	0.9974	93.80
38.5	33,482,161	132,440	0.0040	0.9960	93.55

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1972-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,170,033	221,995	0.0076	0.9924	93.18
40.5	24,548,083	110,636	0.0045	0.9955	92.47
41.5	20,554,488	86,278	0.0042	0.9958	92.05
42.5	16,425,780	41,306	0.0025	0.9975	91.67
43.5	13,367,448	79,803	0.0060	0.9940	91.44
44.5	10,278,704	22,983	0.0022	0.9978	90.89
45.5	7,750,656	29,365	0.0038	0.9962	90.69
46.5	5,714,088	161,243	0.0282	0.9718	90.34
47.5	3,276,827	38,947	0.0119	0.9881	87.79
48.5	1,985,030	16,791	0.0085	0.9915	86.75
49.5	1,086,833	18,214	0.0168	0.9832	86.02
50.5	457,958	7,436	0.0162	0.9838	84.57
51.5	72,565	3,136	0.0432	0.9568	83.20
52.5	42,678	1,561	0.0366	0.9634	79.61
53.5	30,436		0.0000	1.0000	76.69
54.5	15,600	2,265	0.1452	0.8548	76.69
55.5	7,589		0.0000	1.0000	65.56
56.5	7,589		0.0000	1.0000	65.56
57.5	7,589		0.0000	1.0000	65.56
58.5	7,589		0.0000	1.0000	65.56
59.5	7,589		0.0000	1.0000	65.56
60.5	7,589		0.0000	1.0000	65.56
61.5	7,589		0.0000	1.0000	65.56
62.5	7,589		0.0000	1.0000	65.56
63.5	7,589		0.0000	1.0000	65.56
64.5	7,589		0.0000	1.0000	65.56
65.5	7,589		0.0000	1.0000	65.56
66.5	7,589		0.0000	1.0000	65.56
67.5	7,589		0.0000	1.0000	65.56
68.5	7,589	6,389	0.8419	0.1581	65.56
69.5	1,200		0.0000	1.0000	10.37
70.5	1,948		0.0000	1.0000	10.37
71.5	962		0.0000	1.0000	10.37
72.5	962		0.0000	1.0000	10.37
73.5	962		0.0000	1.0000	10.37
74.5	962		0.0000	1.0000	10.37
75.5	962		0.0000	1.0000	10.37
76.5	962		0.0000	1.0000	10.37
77.5	962		0.0000	1.0000	10.37
78.5	962		0.0000	1.0000	10.37

UGI UTILITIES, INC. - GAS DIVISION

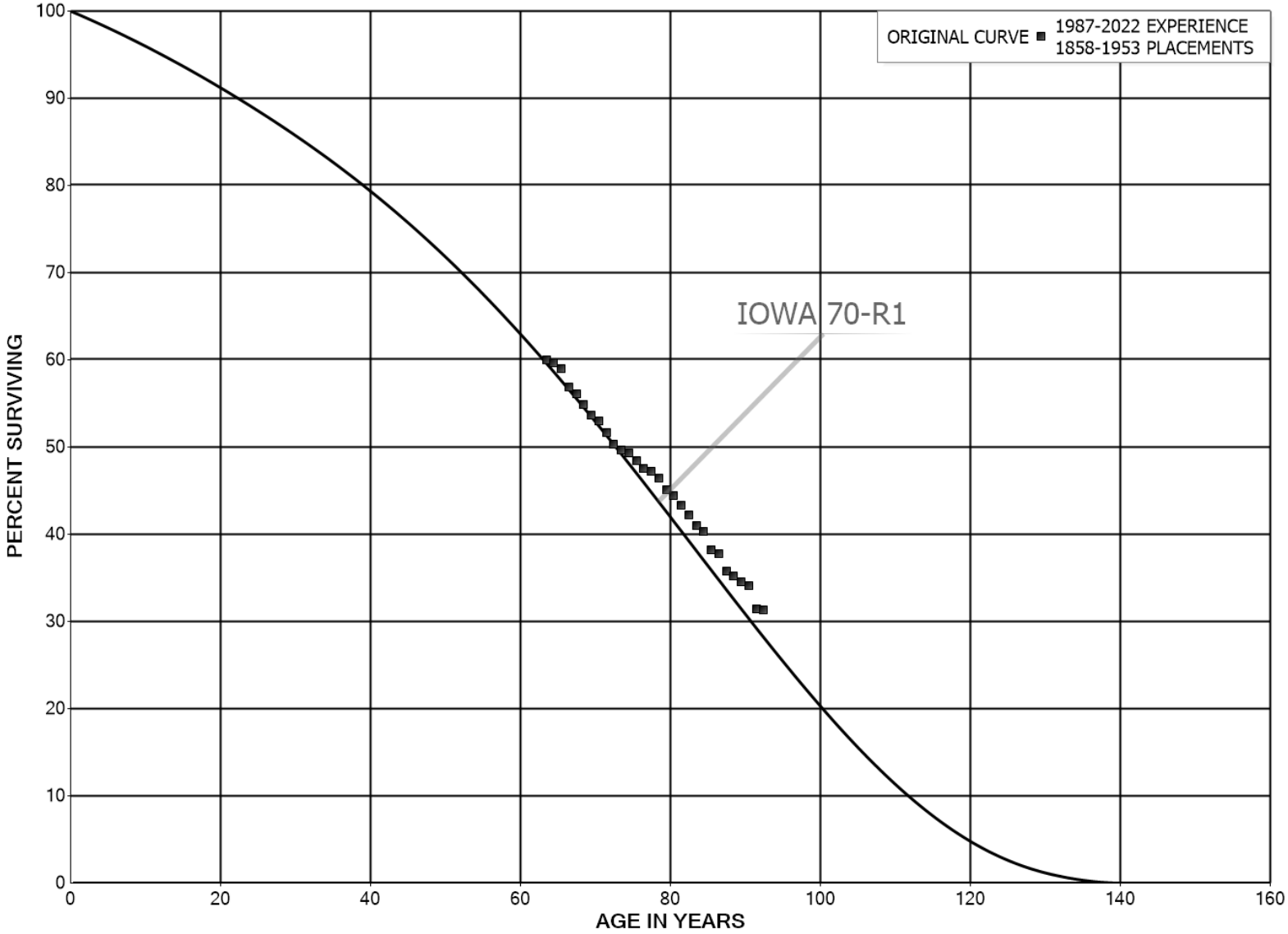
ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1972-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	962		0.0000	1.0000	10.37
80.5	962		0.0000	1.0000	10.37
81.5	962		0.0000	1.0000	10.37
82.5	962		0.0000	1.0000	10.37
83.5	962		0.0000	1.0000	10.37
84.5	962		0.0000	1.0000	10.37
85.5	962		0.0000	1.0000	10.37
86.5	962		0.0000	1.0000	10.37
87.5	962		0.0000	1.0000	10.37
88.5	962		0.0000	1.0000	10.37
89.5	962		0.0000	1.0000	10.37
90.5	962		0.0000	1.0000	10.37
91.5	962		0.0000	1.0000	10.37
92.5	962		0.0000	1.0000	10.37
93.5	962		0.0000	1.0000	10.37
94.5	962		0.0000	1.0000	10.37
95.5	962		0.0000	1.0000	10.37
96.5	962		0.0000	1.0000	10.37
97.5	962		0.0000	1.0000	10.37
98.5	962		0.0000	1.0000	10.37
99.5	962		0.0000	1.0000	10.37
100.5	962		0.0000	1.0000	10.37
101.5	962		0.0000	1.0000	10.37
102.5	962		0.0000	1.0000	10.37
103.5	962		0.0000	1.0000	10.37
104.5	962		0.0000	1.0000	10.37
105.5	962		0.0000	1.0000	10.37
106.5	962		0.0000	1.0000	10.37
107.5	962		0.0000	1.0000	10.37
108.5	962		0.0000	1.0000	10.37
109.5	962		0.0000	1.0000	10.37
110.5	962		0.0000	1.0000	10.37
111.5	962		0.0000	1.0000	10.37
112.5	962		0.0000	1.0000	10.37
113.5	962		0.0000	1.0000	10.37
114.5	962		0.0000	1.0000	10.37
115.5	962		0.0000	1.0000	10.37
116.5	962	748	0.7774	0.2226	10.37
117.5	214		0.0000	1.0000	2.31
118.5	214		0.0000	1.0000	2.31
119.5	214	214	1.0000		2.31
120.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0					
0.5					
1.5					
2.5					
3.5					
4.5					
5.5					
6.5					
7.5					
8.5					
9.5					
10.5					
11.5					
12.5					
13.5					
14.5					
15.5					
16.5					
17.5					
18.5					
19.5					
20.5					
21.5					
22.5					
23.5					
24.5					
25.5					
26.5					
27.5					
28.5					
29.5					
30.5					
31.5					
32.5					
33.5					
34.5					
35.5					
36.5					
37.5					
38.5					

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5					
40.5					
41.5					
42.5					
43.5	25		0.0000		
44.5	25		0.0000		
45.5	25		0.0000		
46.5	55		0.0000		
47.5	223		0.0000		
48.5	262		0.0000		
49.5	262		0.0000		
50.5	262		0.0000		
51.5	262		0.0000		
52.5	262		0.0000		
53.5	262		0.0000		
54.5	262		0.0000		
55.5	262		0.0000		
56.5	262		0.0000		
57.5	262		0.0000		
58.5	314		0.0000		
59.5	314		0.0000		
60.5	314		0.0000		
61.5	314		0.0000		
62.5	75,154		0.0000		
63.5	138,569	982	0.0071	0.9929	60.00
64.5	160,823	1,746	0.0109	0.9891	59.57
65.5	180,613	6,379	0.0353	0.9647	58.93
66.5	181,343	2,380	0.0131	0.9869	56.85
67.5	188,288	4,157	0.0221	0.9779	56.10
68.5	193,984	4,443	0.0229	0.9771	54.86
69.5	198,009	2,263	0.0114	0.9886	53.61
70.5	241,098	6,495	0.0269	0.9731	52.99
71.5	272,551	6,528	0.0240	0.9760	51.57
72.5	360,342	4,768	0.0132	0.9868	50.33
73.5	382,095	3,224	0.0084	0.9916	49.66
74.5	401,702	6,859	0.0171	0.9829	49.25
75.5	423,998	7,571	0.0179	0.9821	48.40
76.5	427,344	2,828	0.0066	0.9934	47.54
77.5	435,068	7,691	0.0177	0.9823	47.23
78.5	435,983	12,197	0.0280	0.9720	46.39

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	427,482	6,709	0.0157	0.9843	45.09
80.5	442,122	11,238	0.0254	0.9746	44.39
81.5	436,692	11,387	0.0261	0.9739	43.26
82.5	434,263	12,079	0.0278	0.9722	42.13
83.5	406,295	6,256	0.0154	0.9846	40.96
84.5	400,819	20,870	0.0521	0.9479	40.33
85.5	383,017	5,350	0.0140	0.9860	38.23
86.5	377,667	19,184	0.0508	0.9492	37.69
87.5	361,149	6,415	0.0178	0.9822	35.78
88.5	355,309	6,314	0.0178	0.9822	35.14
89.5	349,433	4,895	0.0140	0.9860	34.52
90.5	343,947	26,625	0.0774	0.9226	34.03
91.5	332,024	1,439	0.0043	0.9957	31.40
92.5	330,758	3,941	0.0119	0.9881	31.26
93.5	323,763	1,710	0.0053	0.9947	30.89
94.5	322,483	2,890	0.0090	0.9910	30.73
95.5	319,925	1,630	0.0051	0.9949	30.45
96.5	319,583	1,294	0.0040	0.9960	30.30
97.5	318,903	1,379	0.0043	0.9957	30.18
98.5	274,486	916	0.0033	0.9967	30.04
99.5	269,219	1	0.0000	1.0000	29.94
100.5	233,789	626	0.0027	0.9973	29.94
101.5	223,808	524	0.0023	0.9977	29.86
102.5	220,962	87	0.0004	0.9996	29.79
103.5	215,865	897	0.0042	0.9958	29.78
104.5	211,376	90	0.0004	0.9996	29.66
105.5	207,857	279	0.0013	0.9987	29.65
106.5	188,003	40	0.0002	0.9998	29.61
107.5	159,383		0.0000	1.0000	29.60
108.5	108,031	143	0.0013	0.9987	29.60
109.5	87,936	2	0.0000	1.0000	29.56
110.5	72,559	9	0.0001	0.9999	29.56
111.5	52,449	1	0.0000	1.0000	29.56
112.5	43,652	954	0.0219	0.9781	29.56
113.5	36,272	84	0.0023	0.9977	28.91
114.5	29,717	95	0.0032	0.9968	28.84
115.5	26,610	1	0.0000	1.0000	28.75
116.5	21,632	64	0.0030	0.9970	28.75
117.5	18,744	85	0.0045	0.9955	28.67
118.5	10,634		0.0000	1.0000	28.53

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	7,881	30	0.0038	0.9962	28.53
120.5	6,994	39	0.0055	0.9945	28.43
121.5	5,132	150	0.0293	0.9707	28.27
122.5	4,981	174	0.0349	0.9651	27.44
123.5	3,657		0.0000	1.0000	26.48
124.5	3,423	70	0.0203	0.9797	26.48
125.5	3,491	319	0.0914	0.9086	25.95
126.5	3,124	96	0.0306	0.9694	23.58
127.5	2,967		0.0000	1.0000	22.85
128.5	3,316	54	0.0162	0.9838	22.85
129.5	3,036	72	0.0237	0.9763	22.48
130.5	2,957	69	0.0235	0.9765	21.95
131.5	2,696	3	0.0011	0.9989	21.44
132.5	2,663		0.0000	1.0000	21.41
133.5	2,432	1	0.0004	0.9996	21.41
134.5	2,377		0.0000	1.0000	21.40
135.5	2,377		0.0000	1.0000	21.40
136.5	2,374		0.0000	1.0000	21.40
137.5	2,374		0.0000	1.0000	21.40
138.5	2,374		0.0000	1.0000	21.40
139.5	2,293	4	0.0018	0.9982	21.40
140.5	1,783		0.0000	1.0000	21.36
141.5	1,554		0.0000	1.0000	21.36
142.5	1,554		0.0000	1.0000	21.36
143.5	1,554		0.0000	1.0000	21.36
144.5	641		0.0000	1.0000	21.36
145.5	641	9	0.0137	0.9863	21.36
146.5	632		0.0000	1.0000	21.07
147.5	632		0.0000	1.0000	21.07
148.5	630		0.0000	1.0000	21.07
149.5	560		0.0000	1.0000	21.07
150.5	560		0.0000	1.0000	21.07
151.5	560		0.0000	1.0000	21.07
152.5	546		0.0000	1.0000	21.07
153.5	540		0.0000	1.0000	21.07
154.5	523		0.0000	1.0000	21.07
155.5	491		0.0000	1.0000	21.07
156.5	491		0.0000	1.0000	21.07
157.5	491		0.0000	1.0000	21.07
158.5	491		0.0000	1.0000	21.07

UGI UTILITIES, INC. - GAS DIVISION

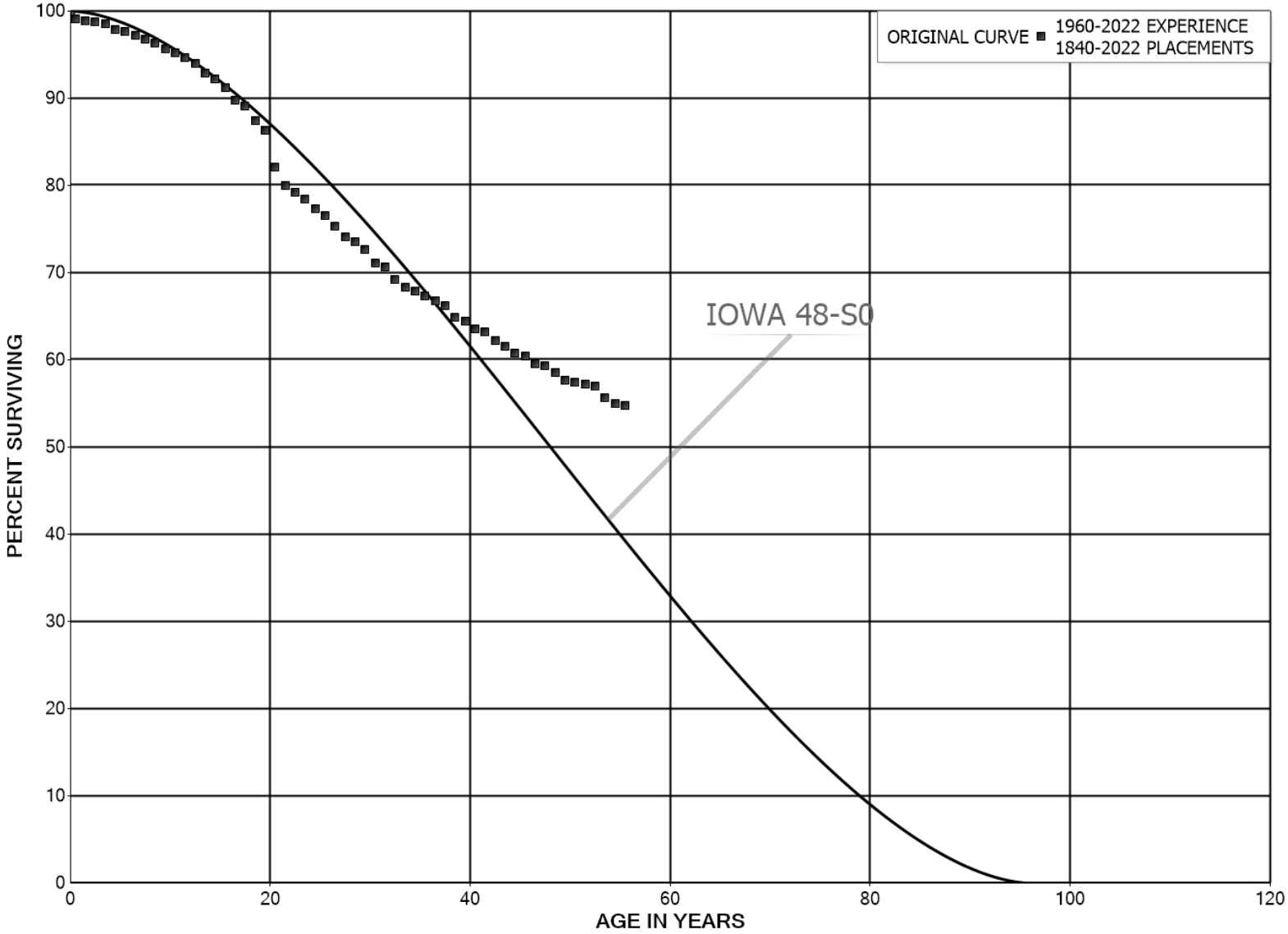
ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	491		0.0000	1.0000	21.07
160.5	491		0.0000	1.0000	21.07
161.5	491		0.0000	1.0000	21.07
162.5	343		0.0000	1.0000	21.07
163.5	341		0.0000	1.0000	21.07
164.5					21.07

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	152,452,628	1,405,089	0.0092	0.9908	100.00
0.5	125,554,924	281,742	0.0022	0.9978	99.08
1.5	110,193,555	136,140	0.0012	0.9988	98.86
2.5	101,234,150	287,815	0.0028	0.9972	98.73
3.5	91,460,817	562,729	0.0062	0.9938	98.45
4.5	79,283,238	208,507	0.0026	0.9974	97.85
5.5	72,396,028	320,854	0.0044	0.9956	97.59
6.5	66,434,100	317,629	0.0048	0.9952	97.16
7.5	56,123,383	231,950	0.0041	0.9959	96.69
8.5	50,977,988	343,148	0.0067	0.9933	96.29
9.5	48,849,144	227,461	0.0047	0.9953	95.65
10.5	45,295,644	303,295	0.0067	0.9933	95.20
11.5	40,344,211	275,438	0.0068	0.9932	94.56
12.5	39,126,552	446,250	0.0114	0.9886	93.92
13.5	37,819,560	260,646	0.0069	0.9931	92.85
14.5	34,835,099	378,939	0.0109	0.9891	92.21
15.5	32,452,182	522,920	0.0161	0.9839	91.20
16.5	30,400,038	243,706	0.0080	0.9920	89.73
17.5	28,740,830	527,898	0.0184	0.9816	89.01
18.5	26,186,178	327,033	0.0125	0.9875	87.38
19.5	23,225,665	1,138,062	0.0490	0.9510	86.29
20.5	21,474,345	547,954	0.0255	0.9745	82.06
21.5	19,315,878	191,836	0.0099	0.9901	79.97
22.5	18,158,348	170,321	0.0094	0.9906	79.17
23.5	17,440,727	250,766	0.0144	0.9856	78.43
24.5	16,093,515	159,592	0.0099	0.9901	77.30
25.5	15,007,032	249,385	0.0166	0.9834	76.53
26.5	13,423,260	205,167	0.0153	0.9847	75.26
27.5	12,400,671	99,924	0.0081	0.9919	74.11
28.5	11,603,994	142,348	0.0123	0.9877	73.52
29.5	11,064,841	228,007	0.0206	0.9794	72.61
30.5	10,286,352	72,318	0.0070	0.9930	71.12
31.5	9,863,472	203,055	0.0206	0.9794	70.62
32.5	9,321,067	112,845	0.0121	0.9879	69.16
33.5	8,603,608	65,279	0.0076	0.9924	68.33
34.5	8,185,970	57,478	0.0070	0.9930	67.81
35.5	7,637,287	69,078	0.0090	0.9910	67.33
36.5	7,149,716	54,254	0.0076	0.9924	66.72
37.5	6,760,227	141,054	0.0209	0.9791	66.22
38.5	6,416,869	46,669	0.0073	0.9927	64.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,041,100	80,724	0.0134	0.9866	64.36
40.5	5,359,210	31,372	0.0059	0.9941	63.50
41.5	4,657,012	66,841	0.0144	0.9856	63.13
42.5	4,342,341	48,340	0.0111	0.9889	62.23
43.5	4,192,710	51,792	0.0124	0.9876	61.53
44.5	4,089,960	25,406	0.0062	0.9938	60.77
45.5	3,796,947	56,879	0.0150	0.9850	60.39
46.5	3,613,927	15,404	0.0043	0.9957	59.49
47.5	3,482,012	42,466	0.0122	0.9878	59.24
48.5	3,301,864	53,064	0.0161	0.9839	58.51
49.5	3,063,413	10,675	0.0035	0.9965	57.57
50.5	2,917,144	10,455	0.0036	0.9964	57.37
51.5	2,542,108	9,446	0.0037	0.9963	57.17
52.5	2,129,008	49,494	0.0232	0.9768	56.96
53.5	1,620,573	19,991	0.0123	0.9877	55.63
54.5	1,399,703	6,071	0.0043	0.9957	54.94
55.5	1,218,784	5,410	0.0044	0.9956	54.71
56.5	1,070,632	2,925	0.0027	0.9973	54.46
57.5	932,602	3,470	0.0037	0.9963	54.31
58.5	846,367	4,229	0.0050	0.9950	54.11
59.5	757,060	3,299	0.0044	0.9956	53.84
60.5	682,428	8,367	0.0123	0.9877	53.61
61.5	610,321	5,230	0.0086	0.9914	52.95
62.5	539,777	6,192	0.0115	0.9885	52.50
63.5	513,598	7,842	0.0153	0.9847	51.89
64.5	407,578	1,976	0.0048	0.9952	51.10
65.5	302,092	3,783	0.0125	0.9875	50.85
66.5	204,556	1,587	0.0078	0.9922	50.22
67.5	170,034	3,889	0.0229	0.9771	49.83
68.5	106,177	853	0.0080	0.9920	48.69
69.5	87,687	116	0.0013	0.9987	48.30
70.5	66,964	971	0.0145	0.9855	48.23
71.5	56,989		0.0000	1.0000	47.53
72.5	44,957	395	0.0088	0.9912	47.53
73.5	42,735	83	0.0019	0.9981	47.12
74.5	40,486	963	0.0238	0.9762	47.02
75.5	36,941	2,158	0.0584	0.9416	45.91
76.5	33,840	749	0.0221	0.9779	43.22
77.5	32,428	830	0.0256	0.9744	42.27
78.5	31,598	297	0.0094	0.9906	41.18

UGI UTILITIES, INC. - GAS DIVISION

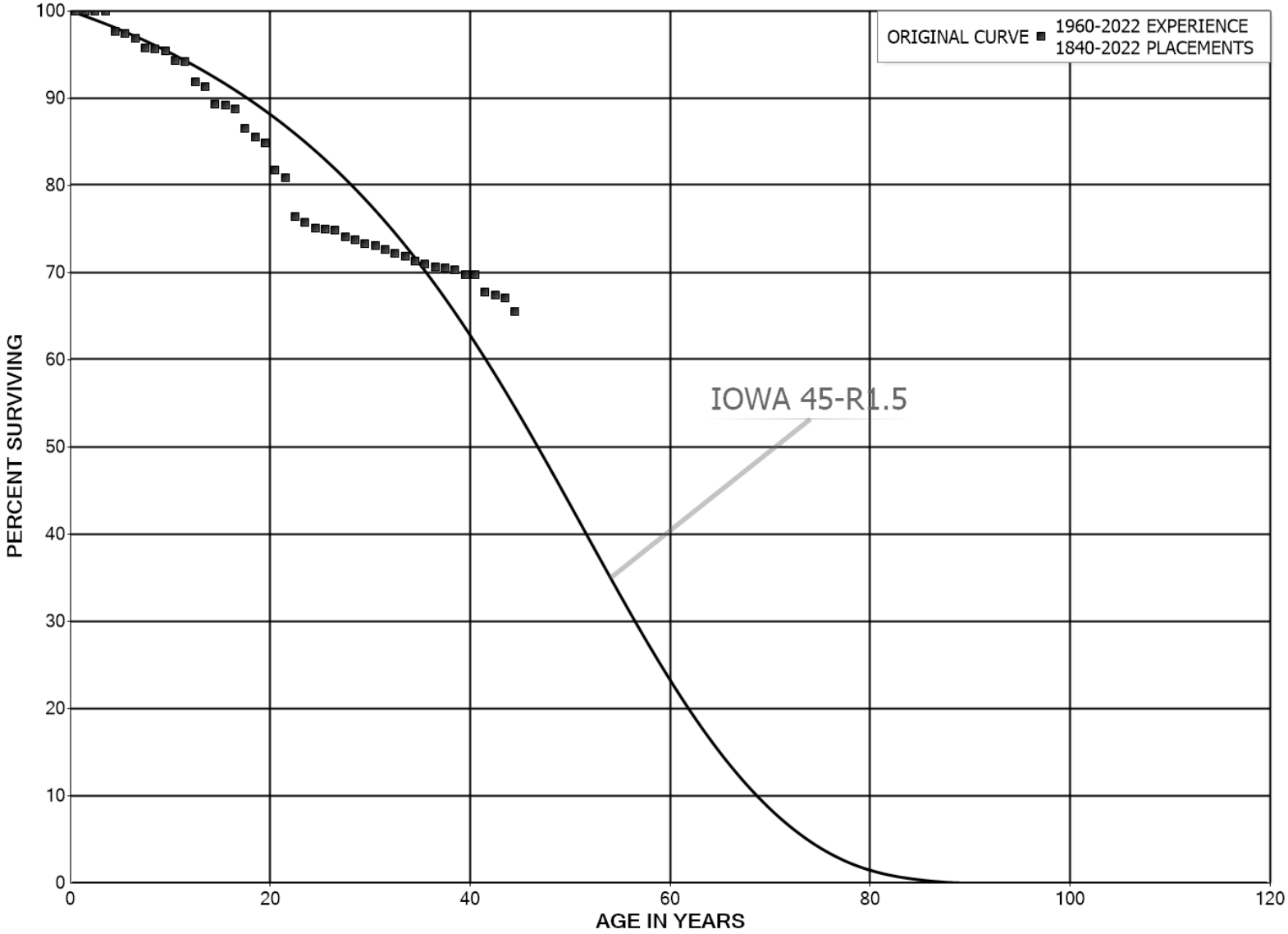
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	30,350	15	0.0005	0.9995	40.80
80.5	27,836		0.0000	1.0000	40.78
81.5	27,666	647	0.0234	0.9766	40.78
82.5	26,395	1,361	0.0516	0.9484	39.82
83.5	24,572		0.0000	1.0000	37.77
84.5	23,467	774	0.0330	0.9670	37.77
85.5	20,919		0.0000	1.0000	36.52
86.5	20,250	574	0.0283	0.9717	36.52
87.5	19,349	206	0.0107	0.9893	35.49
88.5	19,143	536	0.0280	0.9720	35.11
89.5	18,501	1,735	0.0938	0.9062	34.13
90.5	16,542	2,907	0.1757	0.8243	30.93
91.5	11,256	634	0.0563	0.9437	25.49
92.5	9,694		0.0000	1.0000	24.05
93.5	7,143		0.0000	1.0000	24.05
94.5	6,895		0.0000	1.0000	24.05
95.5	4,192		0.0000	1.0000	24.05
96.5	3,063		0.0000	1.0000	24.05
97.5	3,063		0.0000	1.0000	24.05
98.5	2,098		0.0000	1.0000	24.05
99.5	1,507		0.0000	1.0000	24.05
100.5	1,507		0.0000	1.0000	24.05
101.5	1,446		0.0000	1.0000	24.05
102.5	1,244		0.0000	1.0000	24.05
103.5	378		0.0000	1.0000	24.05
104.5	378		0.0000	1.0000	24.05
105.5	378		0.0000	1.0000	24.05
106.5	197		0.0000	1.0000	24.05
107.5	197		0.0000	1.0000	24.05
108.5	197		0.0000	1.0000	24.05
109.5	197		0.0000	1.0000	24.05
110.5	120		0.0000	1.0000	24.05
111.5	60		0.0000	1.0000	24.05
112.5					24.05

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	45,839,018	1,443	0.0000	1.0000	100.00
0.5	33,349,421	561	0.0000	1.0000	100.00
1.5	29,398,314	4,935	0.0002	0.9998	100.00
2.5	27,117,250	21,146	0.0008	0.9992	99.98
3.5	24,668,167	562,857	0.0228	0.9772	99.90
4.5	24,062,434	50,659	0.0021	0.9979	97.62
5.5	24,038,028	139,878	0.0058	0.9942	97.42
6.5	23,912,446	266,526	0.0111	0.9889	96.85
7.5	22,873,702	46,316	0.0020	0.9980	95.77
8.5	14,033,889	31,101	0.0022	0.9978	95.58
9.5	13,629,528	147,762	0.0108	0.9892	95.36
10.5	13,261,882	14,416	0.0011	0.9989	94.33
11.5	10,934,426	276,897	0.0253	0.9747	94.23
12.5	10,390,191	57,117	0.0055	0.9945	91.84
13.5	10,254,033	225,520	0.0220	0.9780	91.34
14.5	9,331,113	11,819	0.0013	0.9987	89.33
15.5	9,315,385	52,748	0.0057	0.9943	89.21
16.5	9,102,405	227,322	0.0250	0.9750	88.71
17.5	8,826,873	106,402	0.0121	0.9879	86.49
18.5	8,634,168	62,228	0.0072	0.9928	85.45
19.5	8,131,857	296,128	0.0364	0.9636	84.84
20.5	7,650,840	83,321	0.0109	0.9891	81.75
21.5	7,398,036	407,157	0.0550	0.9450	80.86
22.5	6,923,259	65,694	0.0095	0.9905	76.41
23.5	6,798,166	59,495	0.0088	0.9912	75.68
24.5	6,617,192	7,218	0.0011	0.9989	75.02
25.5	5,955,518	8,220	0.0014	0.9986	74.94
26.5	5,513,966	53,313	0.0097	0.9903	74.83
27.5	5,133,076	27,973	0.0054	0.9946	74.11
28.5	5,016,608	28,256	0.0056	0.9944	73.71
29.5	4,906,198	14,459	0.0029	0.9971	73.29
30.5	4,691,605	29,442	0.0063	0.9937	73.07
31.5	4,389,271	27,478	0.0063	0.9937	72.62
32.5	4,225,099	16,808	0.0040	0.9960	72.16
33.5	4,162,926	35,687	0.0086	0.9914	71.87
34.5	3,878,212	18,630	0.0048	0.9952	71.26
35.5	3,067,096	12,150	0.0040	0.9960	70.92
36.5	2,788,414	5,828	0.0021	0.9979	70.63
37.5	2,316,071	7,150	0.0031	0.9969	70.49
38.5	2,107,146	15,160	0.0072	0.9928	70.27

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,078,647	651	0.0003	0.9997	69.76
40.5	1,819,522	52,262	0.0287	0.9713	69.74
41.5	984,180	5,688	0.0058	0.9942	67.74
42.5	926,844	4,001	0.0043	0.9957	67.35
43.5	909,267	21,099	0.0232	0.9768	67.06
44.5	880,991	772	0.0009	0.9991	65.50
45.5	874,401	618	0.0007	0.9993	65.44
46.5	860,965		0.0000	1.0000	65.40
47.5	797,187	762	0.0010	0.9990	65.40
48.5	754,115	614	0.0008	0.9992	65.33
49.5	713,889	2,171	0.0030	0.9970	65.28
50.5	672,196		0.0000	1.0000	65.08
51.5	658,732		0.0000	1.0000	65.08
52.5	637,278	611	0.0010	0.9990	65.08
53.5	504,268		0.0000	1.0000	65.02
54.5	376,753	4,048	0.0107	0.9893	65.02
55.5	350,256		0.0000	1.0000	64.32
56.5	213,329		0.0000	1.0000	64.32
57.5	156,398		0.0000	1.0000	64.32
58.5	154,787		0.0000	1.0000	64.32
59.5	126,039		0.0000	1.0000	64.32
60.5	95,390		0.0000	1.0000	64.32
61.5	90,245		0.0000	1.0000	64.32
62.5	46,024		0.0000	1.0000	64.32
63.5	40,476		0.0000	1.0000	64.32
64.5	31,958		0.0000	1.0000	64.32
65.5	25,166		0.0000	1.0000	64.32
66.5	3,876		0.0000	1.0000	64.32
67.5	3,610		0.0000	1.0000	64.32
68.5	2,279		0.0000	1.0000	64.32
69.5	2,279		0.0000	1.0000	64.32
70.5	2,279		0.0000	1.0000	64.32
71.5	2,279		0.0000	1.0000	64.32
72.5	2,279		0.0000	1.0000	64.32
73.5	2,279		0.0000	1.0000	64.32
74.5	2,279		0.0000	1.0000	64.32
75.5	2,279		0.0000	1.0000	64.32
76.5	2,279		0.0000	1.0000	64.32
77.5	2,279		0.0000	1.0000	64.32
78.5	2,279		0.0000	1.0000	64.32

UGI UTILITIES, INC. - GAS DIVISION

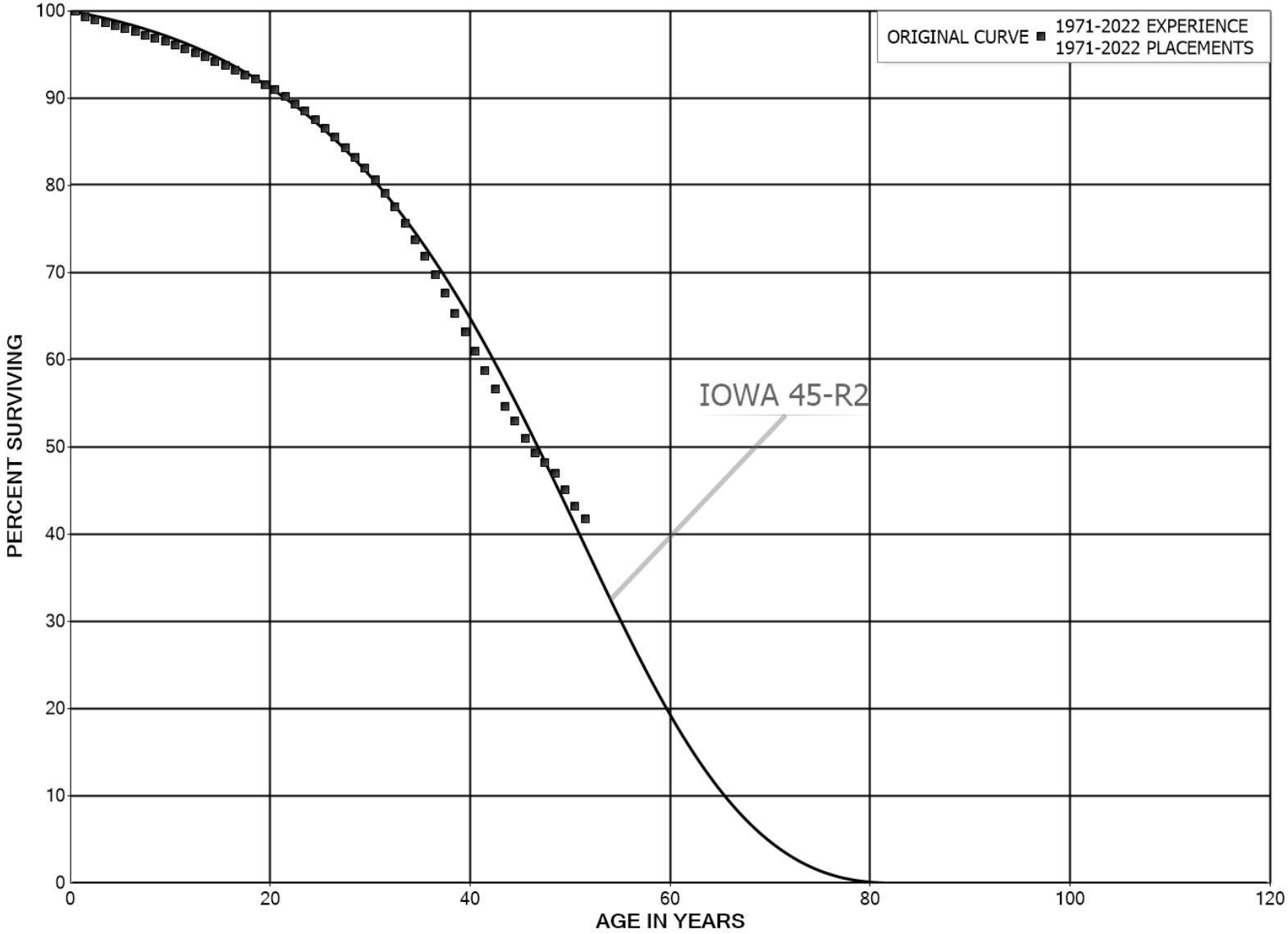
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,279		0.0000	1.0000	64.32
80.5	2,279		0.0000	1.0000	64.32
81.5	2,279		0.0000	1.0000	64.32
82.5	2,279		0.0000	1.0000	64.32
83.5	2,279		0.0000	1.0000	64.32
84.5	2,279		0.0000	1.0000	64.32
85.5	2,279		0.0000	1.0000	64.32
86.5	2,279		0.0000	1.0000	64.32
87.5	2,279		0.0000	1.0000	64.32
88.5	2,279		0.0000	1.0000	64.32
89.5	2,279		0.0000	1.0000	64.32
90.5	2,279		0.0000	1.0000	64.32
91.5	2,279		0.0000	1.0000	64.32
92.5	2,279		0.0000	1.0000	64.32
93.5	2,279		0.0000	1.0000	64.32
94.5	2,279		0.0000	1.0000	64.32
95.5	2,279		0.0000	1.0000	64.32
96.5	2,279		0.0000	1.0000	64.32
97.5	2,279		0.0000	1.0000	64.32
98.5	2,279		0.0000	1.0000	64.32
99.5	2,279	2,279	1.0000		64.32
100.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 380 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2022 EXPERIENCE BAND 1971-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,526,719,555	1,007,995	0.0007	0.9993	100.00
0.5	1,425,968,031	8,814,594	0.0062	0.9938	99.93
1.5	1,296,319,559	4,687,772	0.0036	0.9964	99.32
2.5	1,186,975,777	4,614,551	0.0039	0.9961	98.96
3.5	1,084,326,182	3,178,435	0.0029	0.9971	98.57
4.5	1,006,632,174	3,276,933	0.0033	0.9967	98.28
5.5	937,435,369	3,566,358	0.0038	0.9962	97.96
6.5	865,880,422	3,233,532	0.0037	0.9963	97.59
7.5	799,333,709	2,961,389	0.0037	0.9963	97.23
8.5	738,507,728	3,072,317	0.0042	0.9958	96.87
9.5	678,833,412	2,982,692	0.0044	0.9956	96.46
10.5	628,427,122	2,748,094	0.0044	0.9956	96.04
11.5	592,459,952	2,737,035	0.0046	0.9954	95.62
12.5	567,588,396	2,876,535	0.0051	0.9949	95.18
13.5	542,027,505	2,949,539	0.0054	0.9946	94.70
14.5	514,732,637	2,696,027	0.0052	0.9948	94.18
15.5	493,958,932	2,720,792	0.0055	0.9945	93.69
16.5	474,211,712	2,592,042	0.0055	0.9945	93.17
17.5	451,498,000	2,535,744	0.0056	0.9944	92.66
18.5	424,618,844	2,762,476	0.0065	0.9935	92.14
19.5	404,201,816	2,565,435	0.0063	0.9937	91.54
20.5	382,331,133	3,214,317	0.0084	0.9916	90.96
21.5	360,554,198	3,447,850	0.0096	0.9904	90.20
22.5	341,092,976	3,209,694	0.0094	0.9906	89.33
23.5	321,376,231	3,606,260	0.0112	0.9888	88.49
24.5	299,424,872	3,487,281	0.0116	0.9884	87.50
25.5	275,125,137	3,215,879	0.0117	0.9883	86.48
26.5	253,045,308	3,514,633	0.0139	0.9861	85.47
27.5	228,608,836	3,132,224	0.0137	0.9863	84.28
28.5	206,288,226	2,937,327	0.0142	0.9858	83.13
29.5	191,256,096	3,163,002	0.0165	0.9835	81.94
30.5	172,667,746	3,177,815	0.0184	0.9816	80.59
31.5	155,568,526	3,054,144	0.0196	0.9804	79.11
32.5	135,954,295	3,385,498	0.0249	0.9751	77.55
33.5	117,558,262	2,904,697	0.0247	0.9753	75.62
34.5	102,572,228	2,659,363	0.0259	0.9741	73.75
35.5	90,382,758	2,658,910	0.0294	0.9706	71.84
36.5	80,116,752	2,478,618	0.0309	0.9691	69.73
37.5	70,919,694	2,413,066	0.0340	0.9660	67.57
38.5	62,723,195	1,998,288	0.0319	0.9681	65.27

UGI UTILITIES, INC. - GAS DIVISION

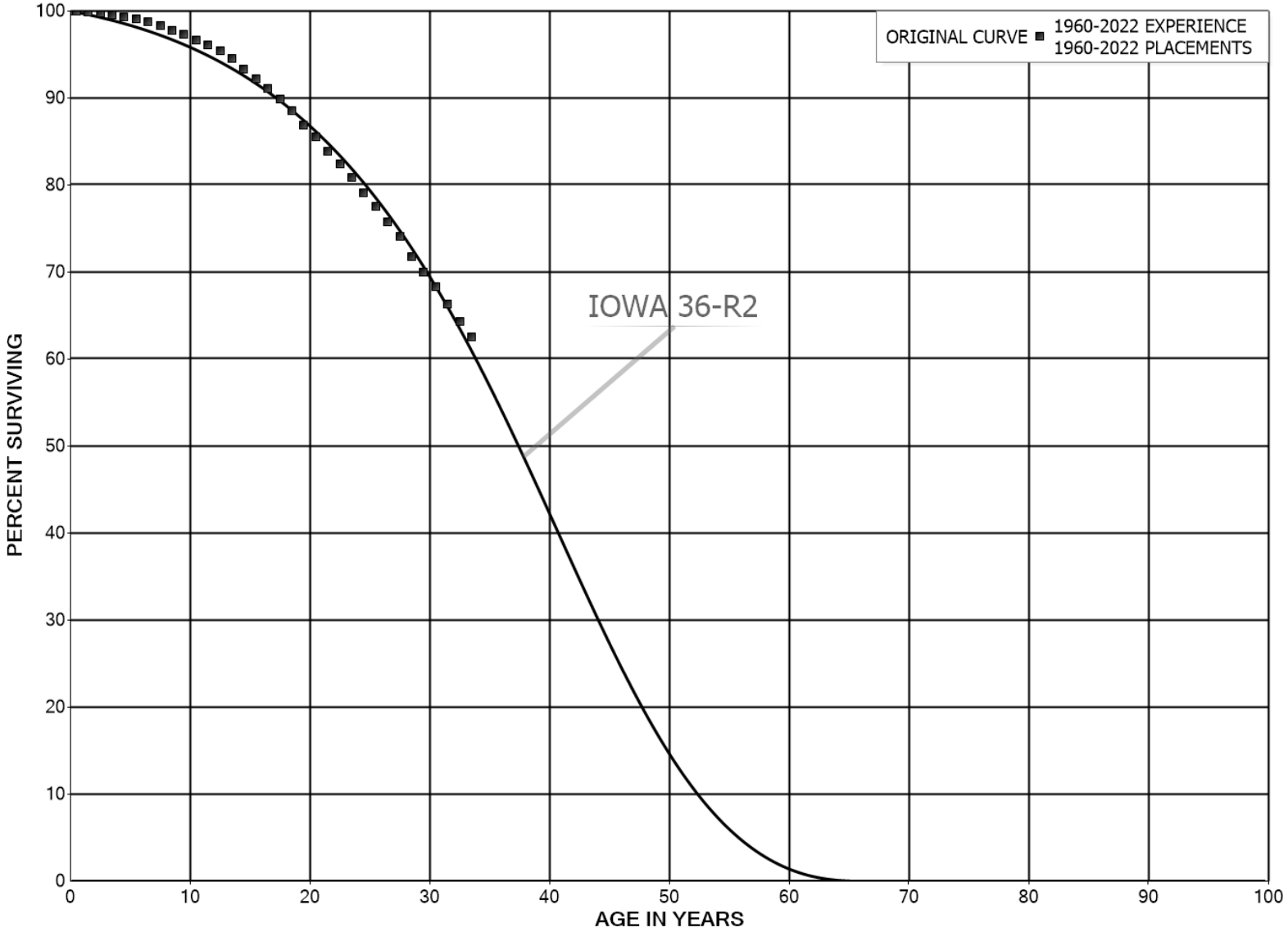
ACCOUNT 380 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-2022 EXPERIENCE BAND 1971-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	55,792,585	1,990,184	0.0357	0.9643	63.19
40.5	47,133,254	1,723,898	0.0366	0.9634	60.94
41.5	37,856,747	1,325,426	0.0350	0.9650	58.71
42.5	28,850,923	1,013,985	0.0351	0.9649	56.65
43.5	22,963,011	718,153	0.0313	0.9687	54.66
44.5	19,124,792	711,053	0.0372	0.9628	52.95
45.5	14,691,293	487,461	0.0332	0.9668	50.98
46.5	11,762,769	265,416	0.0226	0.9774	49.29
47.5	9,326,063	234,078	0.0251	0.9749	48.18
48.5	6,327,673	261,633	0.0413	0.9587	46.97
49.5	3,430,147	143,197	0.0417	0.9583	45.03
50.5	1,259,314	41,445	0.0329	0.9671	43.15
51.5					41.73

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 381 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	188,944,004	4,171	0.0000	1.0000	100.00
0.5	172,992,316	249,387	0.0014	0.9986	100.00
1.5	163,071,232	168,129	0.0010	0.9990	99.85
2.5	154,289,389	306,613	0.0020	0.9980	99.75
3.5	144,838,043	342,024	0.0024	0.9976	99.55
4.5	131,747,222	370,348	0.0028	0.9972	99.32
5.5	123,726,979	396,907	0.0032	0.9968	99.04
6.5	118,017,827	511,776	0.0043	0.9957	98.72
7.5	112,526,084	648,041	0.0058	0.9942	98.29
8.5	106,267,817	516,808	0.0049	0.9951	97.73
9.5	100,023,601	632,641	0.0063	0.9937	97.25
10.5	94,642,979	571,160	0.0060	0.9940	96.64
11.5	89,025,449	609,214	0.0068	0.9932	96.05
12.5	85,681,423	820,692	0.0096	0.9904	95.40
13.5	81,899,953	1,042,210	0.0127	0.9873	94.48
14.5	76,470,089	927,268	0.0121	0.9879	93.28
15.5	72,884,064	842,595	0.0116	0.9884	92.15
16.5	69,482,408	953,674	0.0137	0.9863	91.08
17.5	66,189,780	974,205	0.0147	0.9853	89.83
18.5	62,396,285	1,180,185	0.0189	0.9811	88.51
19.5	59,667,845	919,903	0.0154	0.9846	86.84
20.5	56,856,535	1,087,445	0.0191	0.9809	85.50
21.5	53,529,452	914,517	0.0171	0.9829	83.86
22.5	50,908,815	971,630	0.0191	0.9809	82.43
23.5	48,189,869	1,040,140	0.0216	0.9784	80.86
24.5	44,833,408	897,342	0.0200	0.9800	79.11
25.5	41,813,823	981,851	0.0235	0.9765	77.53
26.5	38,925,035	868,890	0.0223	0.9777	75.71
27.5	36,656,636	1,151,210	0.0314	0.9686	74.02
28.5	32,152,092	769,911	0.0239	0.9761	71.69
29.5	29,266,553	705,220	0.0241	0.9759	69.98
30.5	26,361,450	762,490	0.0289	0.9711	68.29
31.5	23,730,947	714,323	0.0301	0.9699	66.31
32.5	21,329,212	613,881	0.0288	0.9712	64.32
33.5	19,530,764	491,000	0.0251	0.9749	62.47
34.5	18,018,322	407,672	0.0226	0.9774	60.90
35.5	16,592,518	416,370	0.0251	0.9749	59.52
36.5	15,224,804	387,777	0.0255	0.9745	58.03
37.5	13,884,617	296,356	0.0213	0.9787	56.55
38.5	13,136,834	241,633	0.0184	0.9816	55.34

UGI UTILITIES, INC. - GAS DIVISION

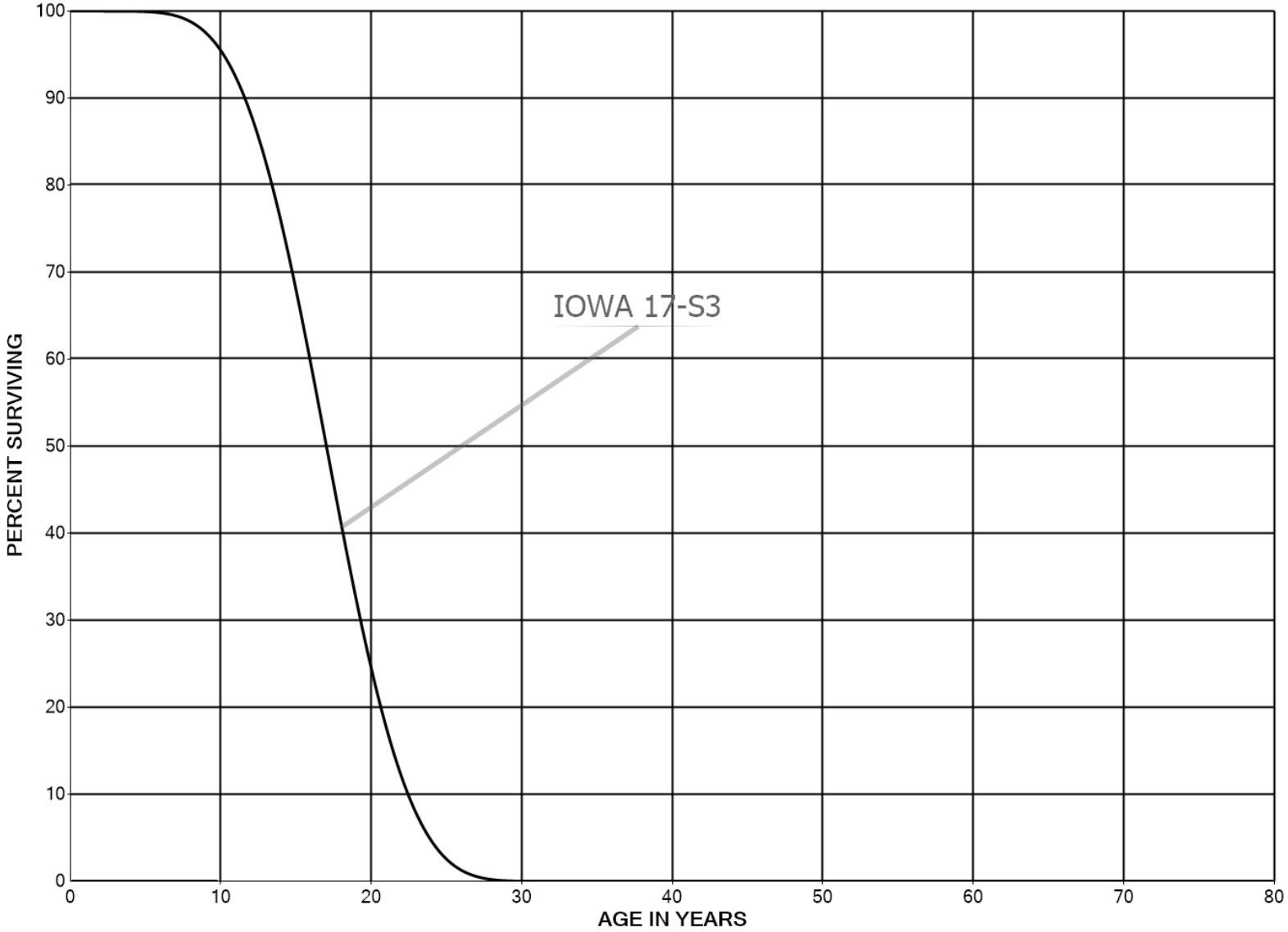
ACCOUNT 381 METERS

ORIGINAL LIFE TABLE, CONT.

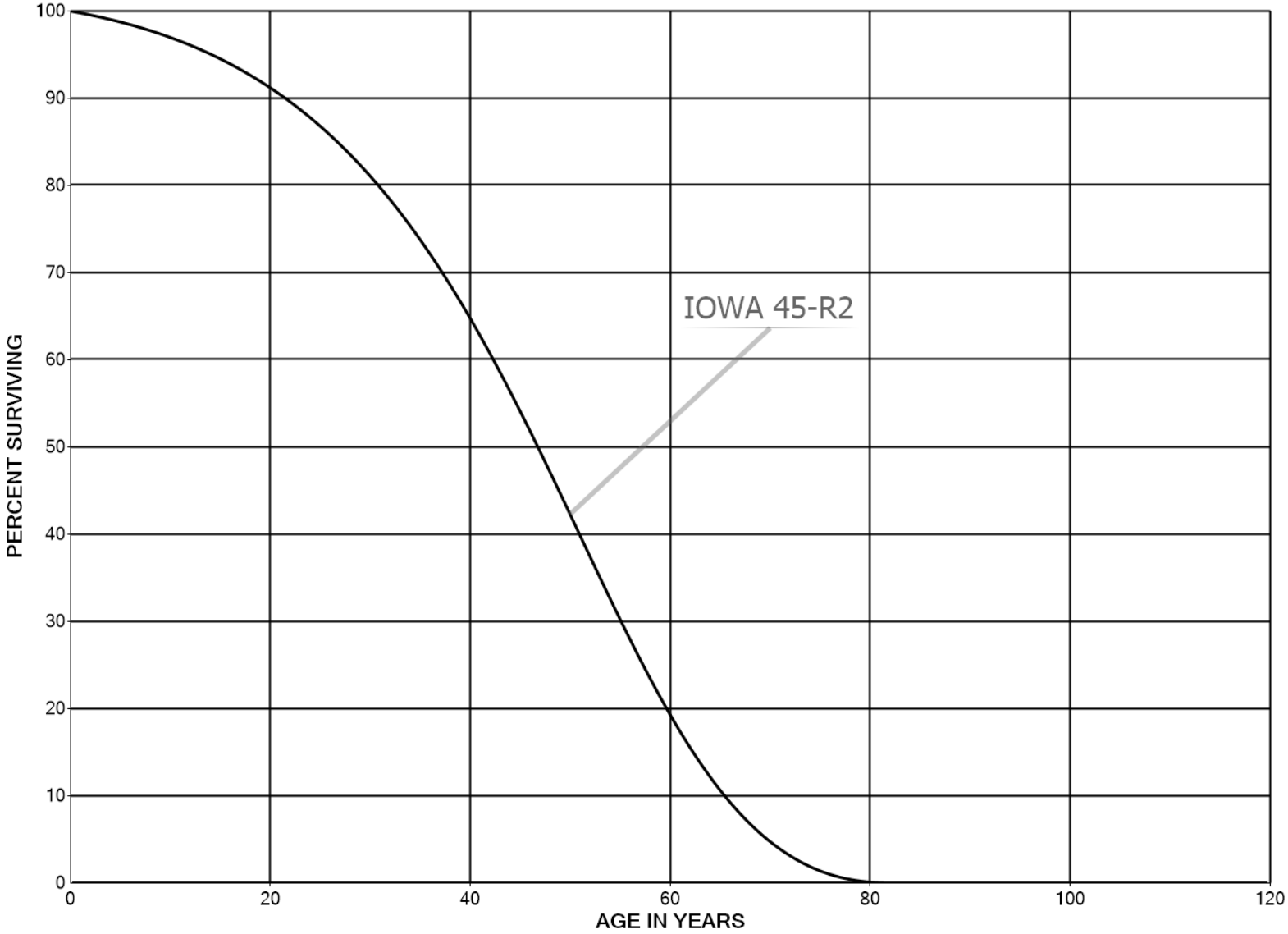
PLACEMENT BAND 1960-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,740,160	308,046	0.0242	0.9758	54.32
40.5	12,024,704	501,124	0.0417	0.9583	53.01
41.5	9,755,899	261,616	0.0268	0.9732	50.80
42.5	7,866,121	240,521	0.0306	0.9694	49.44
43.5	7,350,068	134,573	0.0183	0.9817	47.93
44.5	7,048,532	185,252	0.0263	0.9737	47.05
45.5	6,755,840	170,515	0.0252	0.9748	45.81
46.5	6,484,484	254,243	0.0392	0.9608	44.66
47.5	6,051,799	353,877	0.0585	0.9415	42.91
48.5	5,534,385	378,223	0.0683	0.9317	40.40
49.5	4,875,828	259,756	0.0533	0.9467	37.64
50.5	4,228,295	143,898	0.0340	0.9660	35.63
51.5	3,745,077	134,841	0.0360	0.9640	34.42
52.5	3,081,221	267,528	0.0868	0.9132	33.18
53.5	2,189,761	283,663	0.1295	0.8705	30.30
54.5	1,465,799	63,531	0.0433	0.9567	26.37
55.5	1,060,959	39,778	0.0375	0.9625	25.23
56.5	635,915	7,227	0.0114	0.9886	24.28
57.5	361,992	1,855	0.0051	0.9949	24.01
58.5	211,744	1,596	0.0075	0.9925	23.89
59.5	128,684		0.0000	1.0000	23.71
60.5	58,869		0.0000	1.0000	23.71
61.5	18,375	1,479	0.0805	0.9195	23.71
62.5					21.80

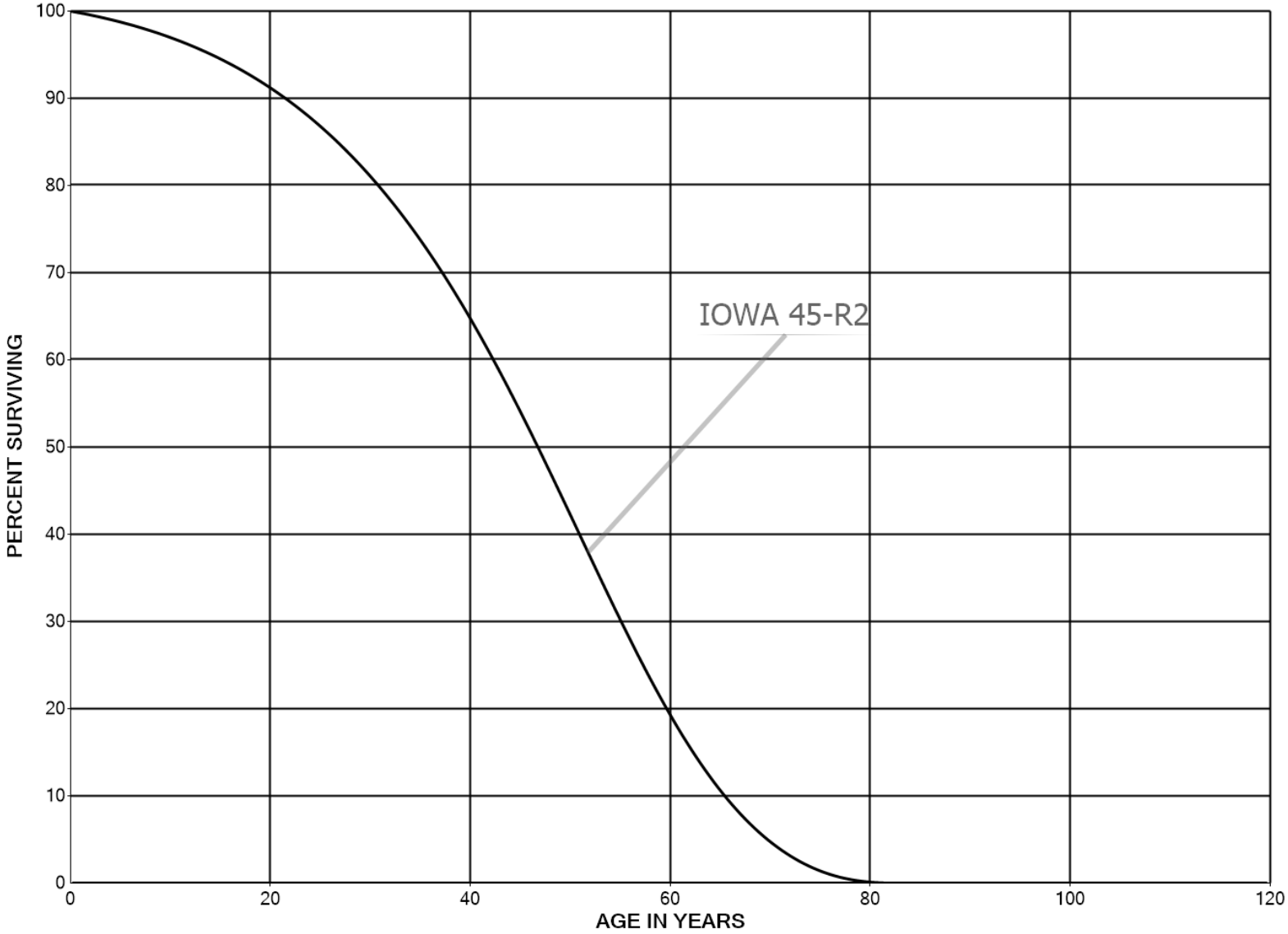
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 381.1 METERS - ERTS
SMOOTH SURVIVOR CURVE



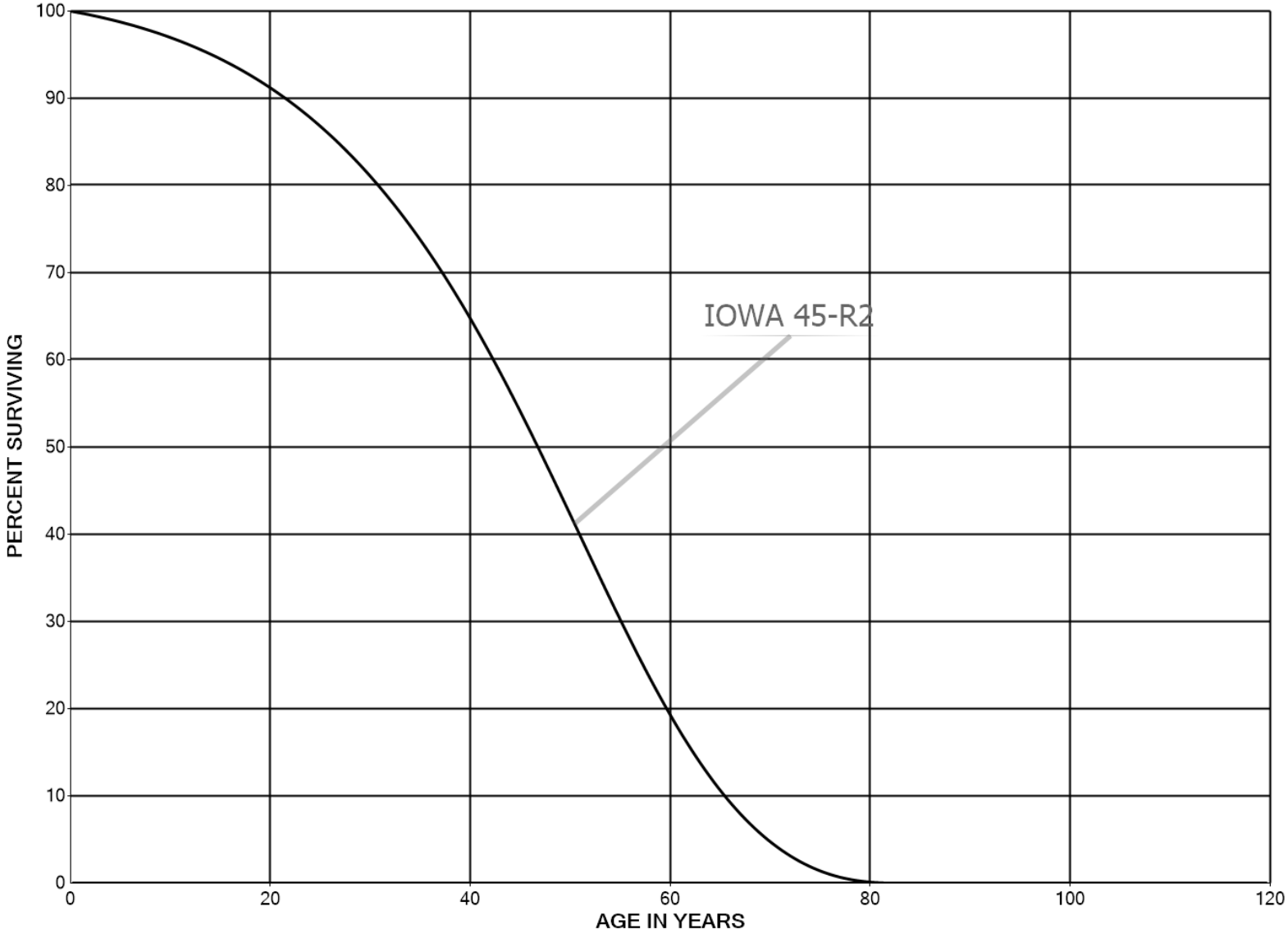
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 382 METER INSTALLATIONS
SMOOTH SURVIVOR CURVE



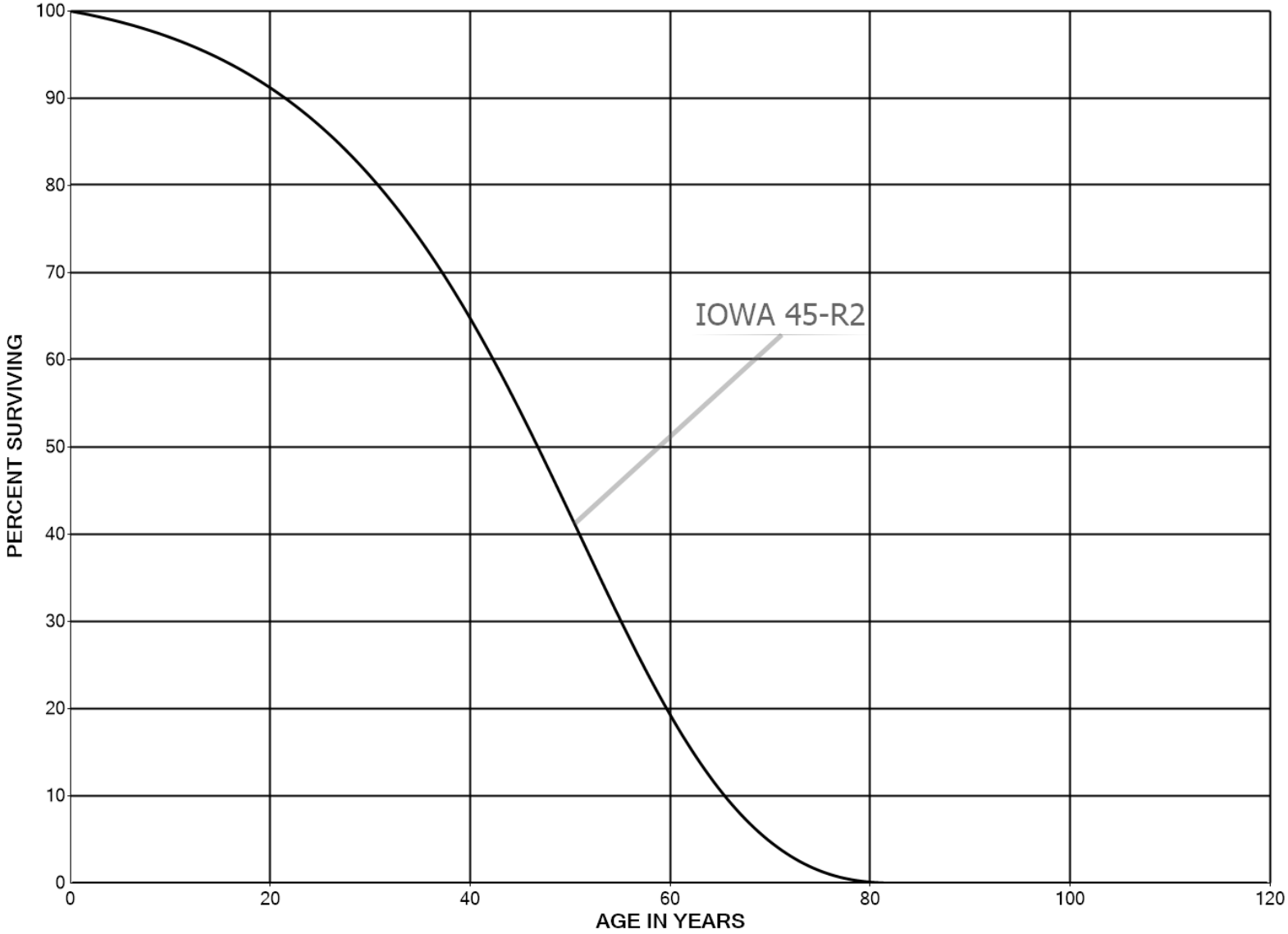
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 383 HOUSE REGULATORS
SMOOTH SURVIVOR CURVE



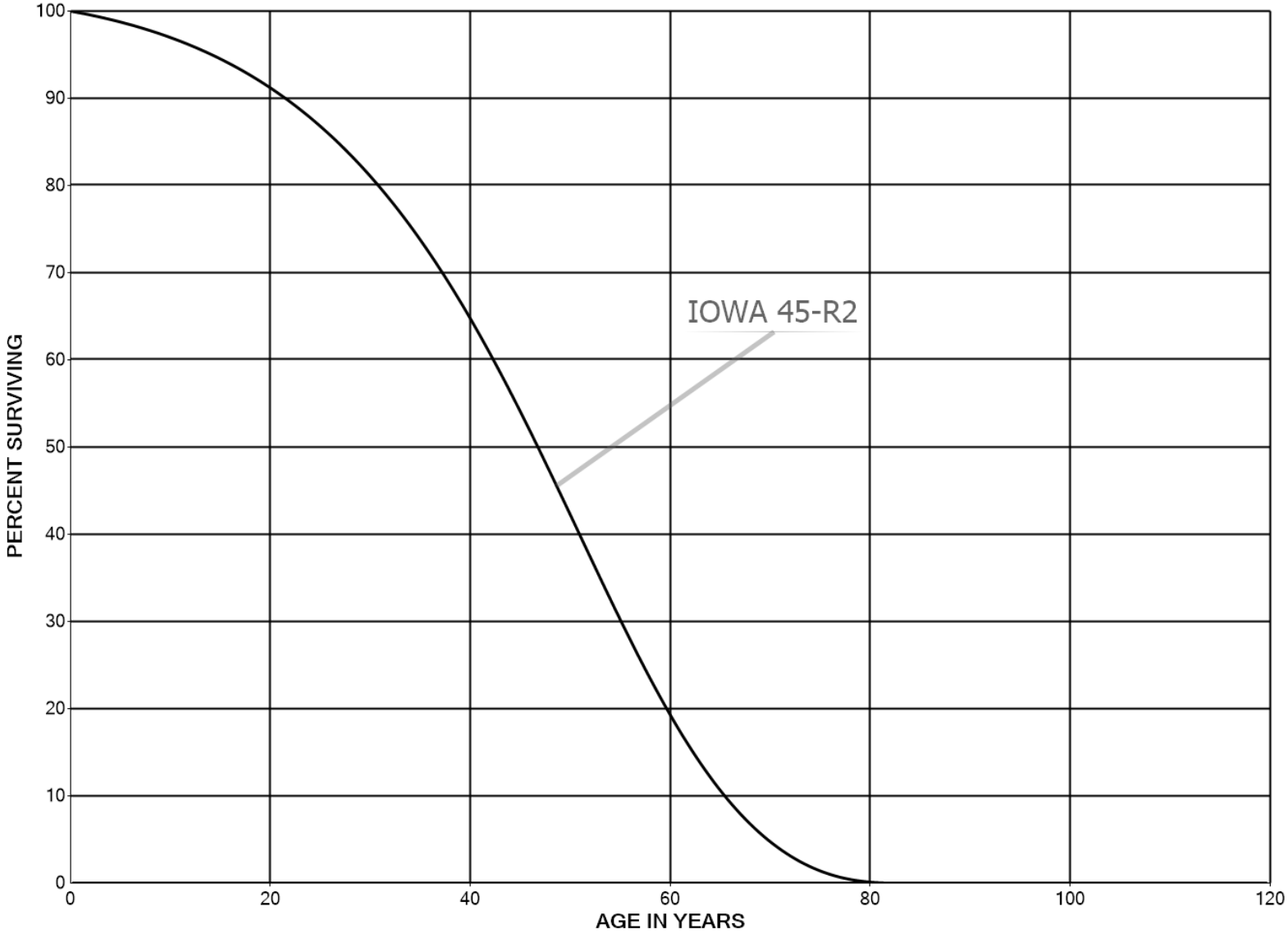
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS
SMOOTH SURVIVOR CURVE



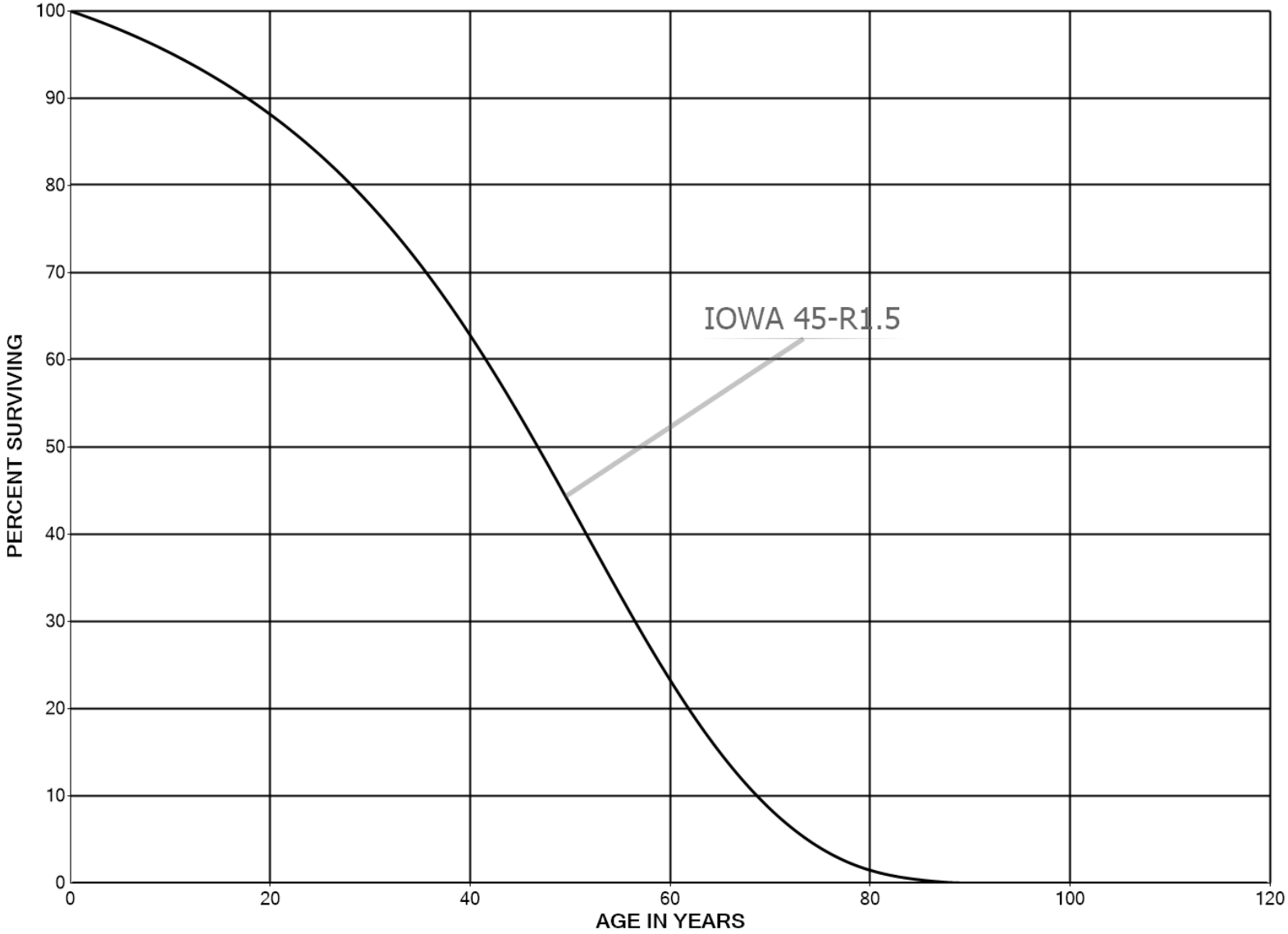
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT
SMOOTH SURVIVOR CURVE



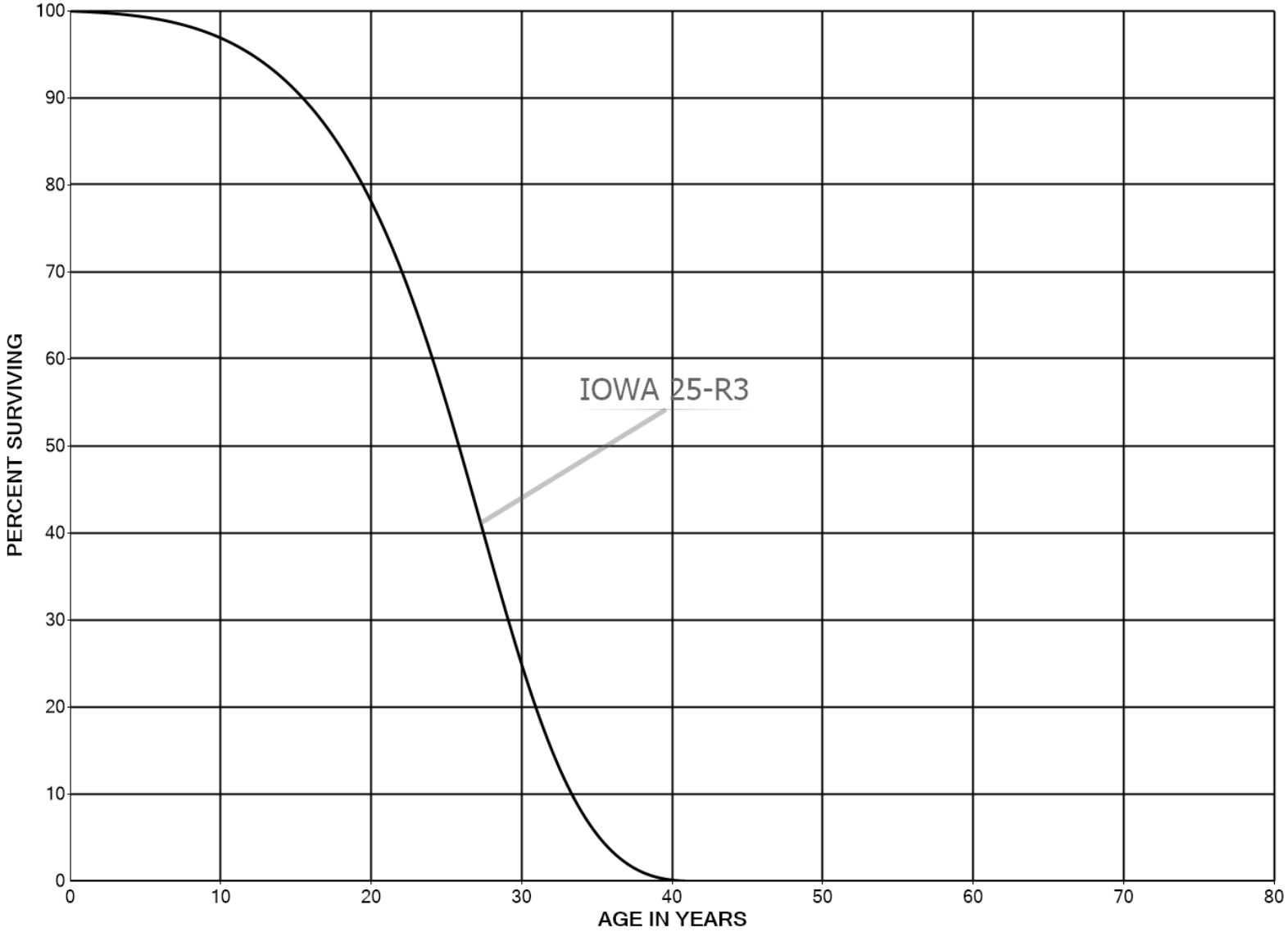
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386 OTHER PROPERTY ON CUSTOMERS PREMISES
SMOOTH SURVIVOR CURVE



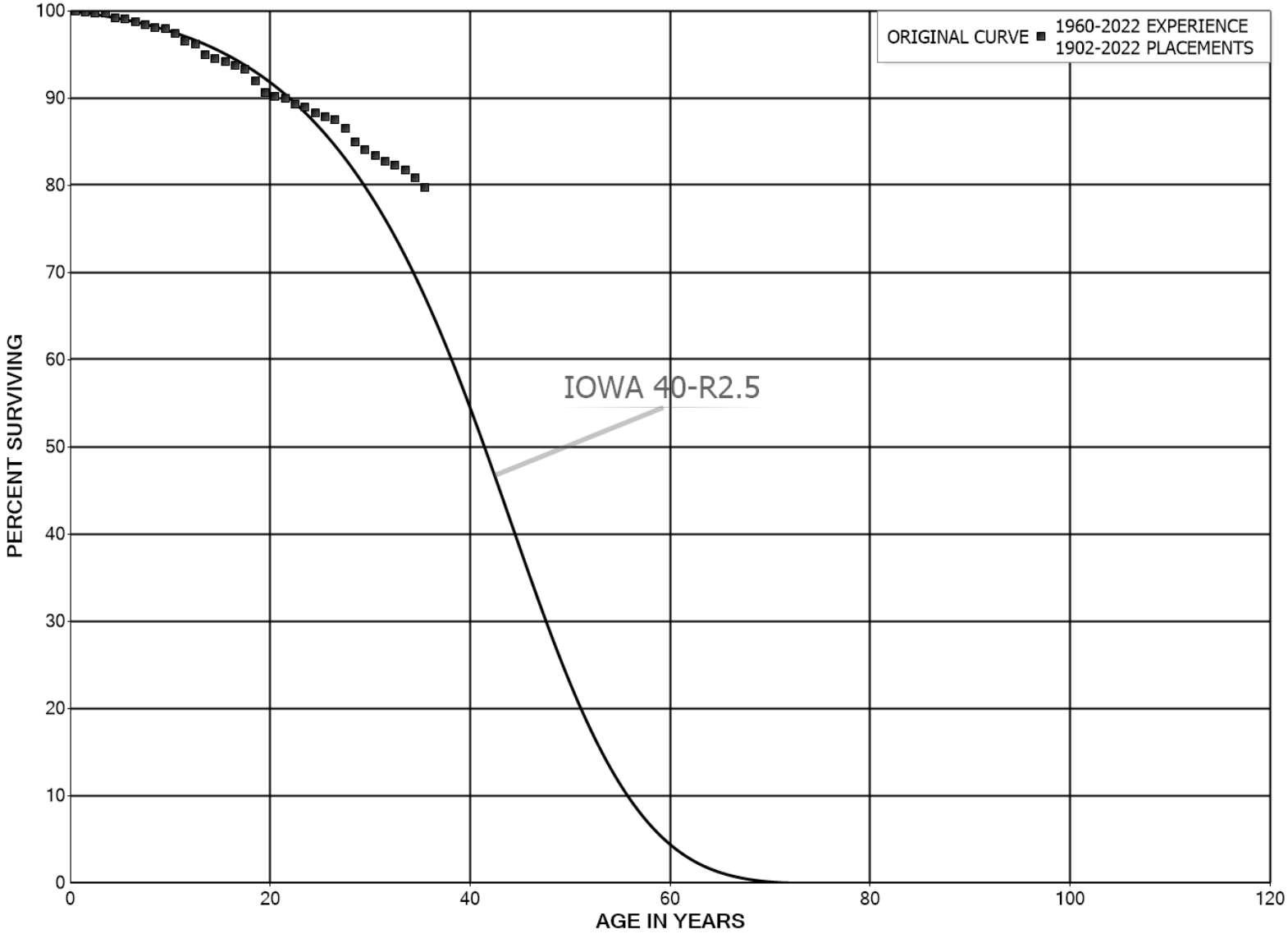
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 387 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,341,099	1,797	0.0003	0.9997	100.00
0.5	5,304,420	4,823	0.0009	0.9991	99.97
1.5	5,205,974	5,904	0.0011	0.9989	99.88
2.5	4,615,477	3,661	0.0008	0.9992	99.76
3.5	4,418,324	22,220	0.0050	0.9950	99.68
4.5	4,204,072	7,215	0.0017	0.9983	99.18
5.5	3,885,994	11,817	0.0030	0.9970	99.01
6.5	3,870,994	14,195	0.0037	0.9963	98.71
7.5	3,878,903	9,657	0.0025	0.9975	98.35
8.5	3,885,739	5,121	0.0013	0.9987	98.10
9.5	3,881,647	23,770	0.0061	0.9939	97.97
10.5	3,859,385	33,413	0.0087	0.9913	97.37
11.5	3,808,853	13,431	0.0035	0.9965	96.53
12.5	3,794,215	46,785	0.0123	0.9877	96.19
13.5	3,691,045	17,544	0.0048	0.9952	95.00
14.5	3,489,686	12,242	0.0035	0.9965	94.55
15.5	3,422,509	17,887	0.0052	0.9948	94.22
16.5	3,331,995	16,349	0.0049	0.9951	93.73
17.5	3,245,233	45,932	0.0142	0.9858	93.27
18.5	3,080,342	44,665	0.0145	0.9855	91.95
19.5	2,815,290	13,736	0.0049	0.9951	90.62
20.5	2,780,451	8,224	0.0030	0.9970	90.17
21.5	2,634,614	16,888	0.0064	0.9936	89.91
22.5	2,357,799	10,549	0.0045	0.9955	89.33
23.5	1,946,061	12,959	0.0067	0.9933	88.93
24.5	1,843,744	11,245	0.0061	0.9939	88.34
25.5	1,670,116	5,396	0.0032	0.9968	87.80
26.5	1,410,315	16,718	0.0119	0.9881	87.52
27.5	1,245,678	22,644	0.0182	0.9818	86.48
28.5	1,122,489	10,876	0.0097	0.9903	84.91
29.5	1,026,515	8,557	0.0083	0.9917	84.08
30.5	956,341	7,005	0.0073	0.9927	83.38
31.5	852,068	4,887	0.0057	0.9943	82.77
32.5	760,032	5,491	0.0072	0.9928	82.30
33.5	673,128	6,950	0.0103	0.9897	81.70
34.5	621,046	8,595	0.0138	0.9862	80.86
35.5	542,553	9,163	0.0169	0.9831	79.74
36.5	483,190	3,020	0.0063	0.9937	78.39
37.5	441,552	5,818	0.0132	0.9868	77.90
38.5	379,145	2,078	0.0055	0.9945	76.88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	363,714	5,093	0.0140	0.9860	76.46
40.5	328,506	1,812	0.0055	0.9945	75.39
41.5	304,203	1,844	0.0061	0.9939	74.97
42.5	285,441	1,514	0.0053	0.9947	74.52
43.5	274,957	5,625	0.0205	0.9795	74.12
44.5	266,684	725	0.0027	0.9973	72.60
45.5	261,475	4,885	0.0187	0.9813	72.41
46.5	230,927	9,449	0.0409	0.9591	71.05
47.5	238,740	409	0.0017	0.9983	68.15
48.5	232,056	744	0.0032	0.9968	68.03
49.5	227,979	202	0.0009	0.9991	67.81
50.5	213,219	373	0.0018	0.9982	67.75
51.5	223,296	2,683	0.0120	0.9880	67.63
52.5	217,469	1,586	0.0073	0.9927	66.82
53.5	214,320	902	0.0042	0.9958	66.33
54.5	195,966	3,721	0.0190	0.9810	66.05
55.5	179,652	222	0.0012	0.9988	64.80
56.5	171,188	1,774	0.0104	0.9896	64.72
57.5	169,986	510	0.0030	0.9970	64.05
58.5	162,243	3,025	0.0186	0.9814	63.86
59.5	155,738	19,627	0.1260	0.8740	62.67
60.5	133,265	94	0.0007	0.9993	54.77
61.5	130,270	559	0.0043	0.9957	54.73
62.5	124,157	468	0.0038	0.9962	54.50
63.5	103,923	2,539	0.0244	0.9756	54.29
64.5	100,025	355	0.0036	0.9964	52.96
65.5	97,597	59	0.0006	0.9994	52.78
66.5	85,715		0.0000	1.0000	52.74
67.5	84,247	2,899	0.0344	0.9656	52.74
68.5	75,304	231	0.0031	0.9969	50.93
69.5	44,947	192	0.0043	0.9957	50.77
70.5	43,230	3,071	0.0710	0.9290	50.56
71.5	38,675	83	0.0022	0.9978	46.96
72.5	30,220		0.0000	1.0000	46.86
73.5	8,033		0.0000	1.0000	46.86
74.5	7,805		0.0000	1.0000	46.86
75.5	7,242		0.0000	1.0000	46.86
76.5	16,082		0.0000	1.0000	46.86
77.5	16,082		0.0000	1.0000	46.86
78.5	16,225		0.0000	1.0000	46.86

UGI UTILITIES, INC. - GAS DIVISION

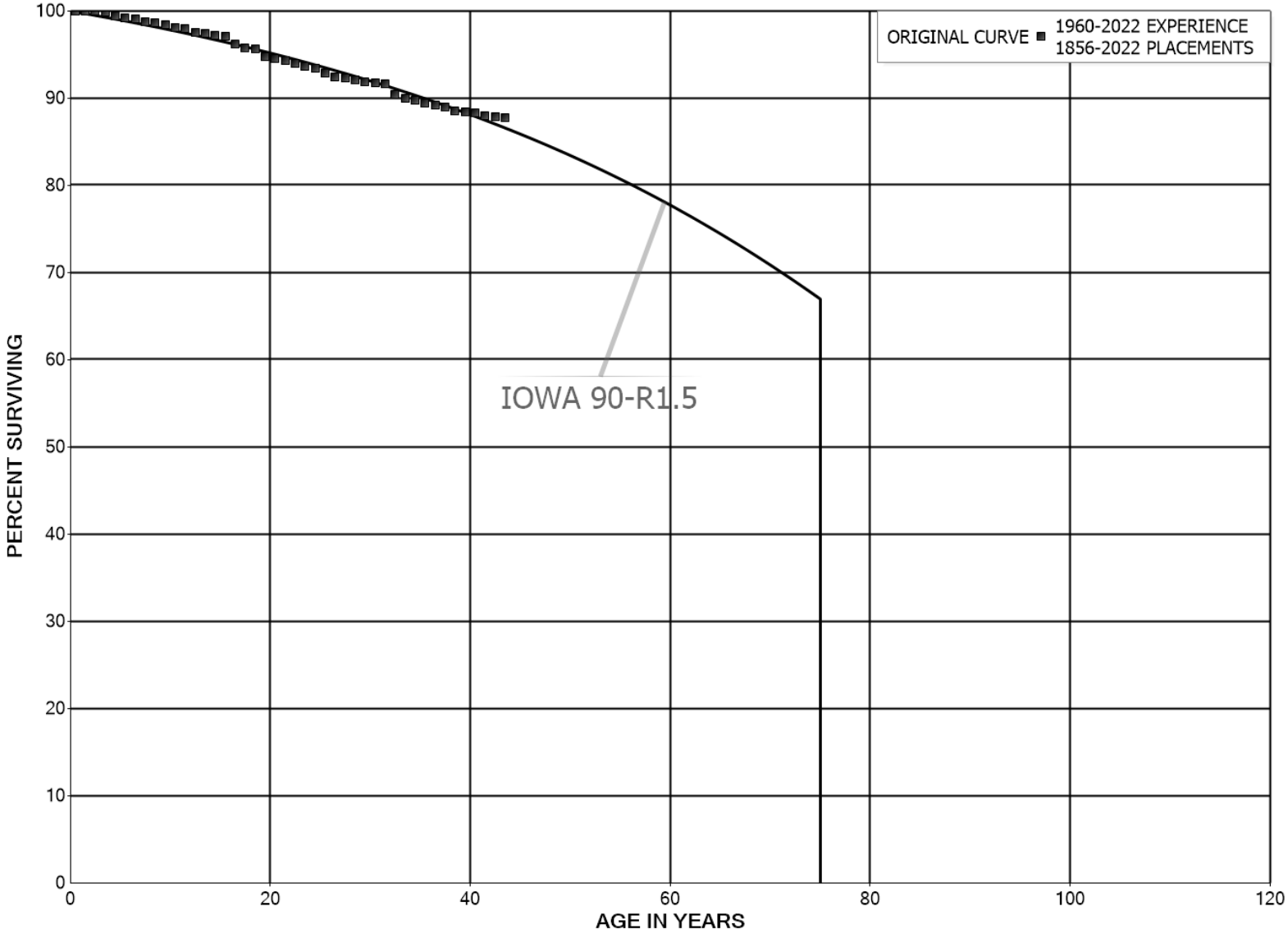
ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	16,225	2,002	0.1234	0.8766	46.86
80.5	14,129	114	0.0080	0.9920	41.08
81.5	14,281	12	0.0008	0.9992	40.75
82.5	14,155		0.0000	1.0000	40.72
83.5	14,085	545	0.0387	0.9613	40.72
84.5	12,838	343	0.0267	0.9733	39.14
85.5	12,315		0.0000	1.0000	38.09
86.5	11,975		0.0000	1.0000	38.09
87.5	11,975		0.0000	1.0000	38.09
88.5	11,975		0.0000	1.0000	38.09
89.5	11,795		0.0000	1.0000	38.09
90.5	10,933		0.0000	1.0000	38.09
91.5	10,357		0.0000	1.0000	38.09
92.5	9,955		0.0000	1.0000	38.09
93.5	9,923		0.0000	1.0000	38.09
94.5	9,923		0.0000	1.0000	38.09
95.5	9,657		0.0000	1.0000	38.09
96.5	9,649		0.0000	1.0000	38.09
97.5	9,360		0.0000	1.0000	38.09
98.5	519		0.0000	1.0000	38.09
99.5	519		0.0000	1.0000	38.09
100.5	377		0.0000	1.0000	38.09
101.5	312		0.0000	1.0000	38.09
102.5	266		0.0000	1.0000	38.09
103.5	0		0.0000	1.0000	38.09
104.5	0		0.0000	1.0000	38.09
105.5	0		0.0000	1.0000	38.09
106.5	0		0.0000	1.0000	38.09
107.5					38.09

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - MAJOR STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - MAJOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1856-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	129,460,994	3,549	0.0000	1.0000	100.00
0.5	119,359,740	3,390	0.0000	1.0000	100.00
1.5	82,152,908	39,075	0.0005	0.9995	99.99
2.5	80,220,640	58,172	0.0007	0.9993	99.95
3.5	73,618,339	359,012	0.0049	0.9951	99.87
4.5	69,110,983	139,590	0.0020	0.9980	99.39
5.5	66,794,458	85,271	0.0013	0.9987	99.19
6.5	64,895,582	200,300	0.0031	0.9969	99.06
7.5	62,972,904	85,163	0.0014	0.9986	98.75
8.5	60,595,429	144,738	0.0024	0.9976	98.62
9.5	60,002,582	184,723	0.0031	0.9969	98.39
10.5	59,269,360	95,676	0.0016	0.9984	98.08
11.5	57,353,015	238,594	0.0042	0.9958	97.92
12.5	56,891,265	90,904	0.0016	0.9984	97.52
13.5	50,960,191	69,904	0.0014	0.9986	97.36
14.5	49,408,198	84,770	0.0017	0.9983	97.23
15.5	47,230,152	428,894	0.0091	0.9909	97.06
16.5	46,078,650	193,817	0.0042	0.9958	96.18
17.5	41,695,469	71,912	0.0017	0.9983	95.77
18.5	39,817,430	380,803	0.0096	0.9904	95.61
19.5	38,501,317	58,058	0.0015	0.9985	94.69
20.5	34,394,514	116,620	0.0034	0.9966	94.55
21.5	32,175,629	110,601	0.0034	0.9966	94.23
22.5	29,191,998	106,293	0.0036	0.9964	93.91
23.5	28,732,107	65,373	0.0023	0.9977	93.57
24.5	27,149,938	139,351	0.0051	0.9949	93.35
25.5	21,350,064	98,852	0.0046	0.9954	92.87
26.5	20,691,284	44,302	0.0021	0.9979	92.44
27.5	20,251,792	40,698	0.0020	0.9980	92.25
28.5	17,791,037	34,778	0.0020	0.9980	92.06
29.5	16,516,493	19,420	0.0012	0.9988	91.88
30.5	14,060,249	29,753	0.0021	0.9979	91.77
31.5	13,719,699	178,289	0.0130	0.9870	91.58
32.5	12,455,446	58,171	0.0047	0.9953	90.39
33.5	10,892,254	32,021	0.0029	0.9971	89.97
34.5	10,526,621	29,621	0.0028	0.9972	89.70
35.5	10,280,650	37,419	0.0036	0.9964	89.45
36.5	9,850,956	16,721	0.0017	0.9983	89.12
37.5	10,210,179	49,721	0.0049	0.9951	88.97
38.5	9,923,794	12,548	0.0013	0.9987	88.54

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - MAJOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,811,471	21,175	0.0022	0.9978	88.43
40.5	9,663,647	29,888	0.0031	0.9969	88.24
41.5	9,480,476	10,385	0.0011	0.9989	87.96
42.5	8,898,381	12,154	0.0014	0.9986	87.87
43.5	8,689,822	8,016	0.0009	0.9991	87.75
44.5	8,635,757	34,589	0.0040	0.9960	87.67
45.5	8,272,827	40,328	0.0049	0.9951	87.31
46.5	7,684,750	13,022	0.0017	0.9983	86.89
47.5	7,548,350	1,520	0.0002	0.9998	86.74
48.5	6,320,928	3,133	0.0005	0.9995	86.72
49.5	6,207,464	2,065	0.0003	0.9997	86.68
50.5	6,174,897	4,456	0.0007	0.9993	86.65
51.5	5,753,256	5,107	0.0009	0.9991	86.59
52.5	5,699,296	5,710	0.0010	0.9990	86.51
53.5	5,663,699	16,611	0.0029	0.9971	86.43
54.5	5,627,458	428	0.0001	0.9999	86.17
55.5	5,568,879	863	0.0002	0.9998	86.17
56.5	5,410,444	3,727	0.0007	0.9993	86.15
57.5	3,843,139	95,265	0.0248	0.9752	86.09
58.5	3,736,576	5,179	0.0014	0.9986	83.96
59.5	3,721,850	8,734	0.0023	0.9977	83.84
60.5	3,546,062		0.0000	1.0000	83.65
61.5	2,882,600	18,846	0.0065	0.9935	83.65
62.5	2,673,590	2,394	0.0009	0.9991	83.10
63.5	2,620,601	320	0.0001	0.9999	83.03
64.5	2,595,232	15,600	0.0060	0.9940	83.02
65.5	2,564,507	207	0.0001	0.9999	82.52
66.5	2,532,685	188	0.0001	0.9999	82.51
67.5	1,715,759	408	0.0002	0.9998	82.50
68.5	1,382,324	6,541	0.0047	0.9953	82.48
69.5	1,329,452	1,215	0.0009	0.9991	82.09
70.5	1,308,947	5,352	0.0041	0.9959	82.02
71.5	1,285,537	5,681	0.0044	0.9956	81.68
72.5	1,209,070	9,883	0.0082	0.9918	81.32
73.5	687,765	2,283	0.0033	0.9967	80.66
74.5	684,932	522	0.0008	0.9992	80.39
75.5	675,764	27,870	0.0412	0.9588	80.33
76.5	659,411	7,789	0.0118	0.9882	77.02
77.5	648,823	1,000	0.0015	0.9985	76.11
78.5	647,284	123	0.0002	0.9998	75.99

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - MAJOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	463,812	200	0.0004	0.9996	75.97
80.5	461,775	50	0.0001	0.9999	75.94
81.5	459,513	1,401	0.0030	0.9970	75.93
82.5	449,828	480	0.0011	0.9989	75.70
83.5	377,336	5,349	0.0142	0.9858	75.62
84.5	360,170	304	0.0008	0.9992	74.55
85.5	355,808		0.0000	1.0000	74.49
86.5	356,891	7,373	0.0207	0.9793	74.49
87.5	320,200	8,071	0.0252	0.9748	72.95
88.5	313,689		0.0000	1.0000	71.11
89.5	312,949		0.0000	1.0000	71.11
90.5	312,048		0.0000	1.0000	71.11
91.5	271,802	11,745	0.0432	0.9568	71.11
92.5	228,864	189	0.0008	0.9992	68.04
93.5	178,729	1,500	0.0084	0.9916	67.98
94.5	135,161		0.0000	1.0000	67.41
95.5	135,161		0.0000	1.0000	67.41
96.5	131,348		0.0000	1.0000	67.41
97.5	131,348		0.0000	1.0000	67.41
98.5	126,683		0.0000	1.0000	67.41
99.5	124,415	268	0.0022	0.9978	67.41
100.5	121,405		0.0000	1.0000	67.26
101.5	118,675		0.0000	1.0000	67.26
102.5	95,363	561	0.0059	0.9941	67.26
103.5	94,803	2,830	0.0299	0.9701	66.87
104.5	84,483		0.0000	1.0000	64.87
105.5	84,483		0.0000	1.0000	64.87
106.5	84,483		0.0000	1.0000	64.87
107.5	81,635		0.0000	1.0000	64.87
108.5	77,043	486	0.0063	0.9937	64.87
109.5	75,557		0.0000	1.0000	64.46
110.5	73,759		0.0000	1.0000	64.46
111.5	73,496		0.0000	1.0000	64.46
112.5	66,292		0.0000	1.0000	64.46
113.5	65,815		0.0000	1.0000	64.46
114.5	65,815	2,723	0.0414	0.9586	64.46
115.5	61,599		0.0000	1.0000	61.80
116.5	61,307		0.0000	1.0000	61.80
117.5	59,282		0.0000	1.0000	61.80
118.5	59,282		0.0000	1.0000	61.80

UGI UTILITIES, INC. - GAS DIVISION

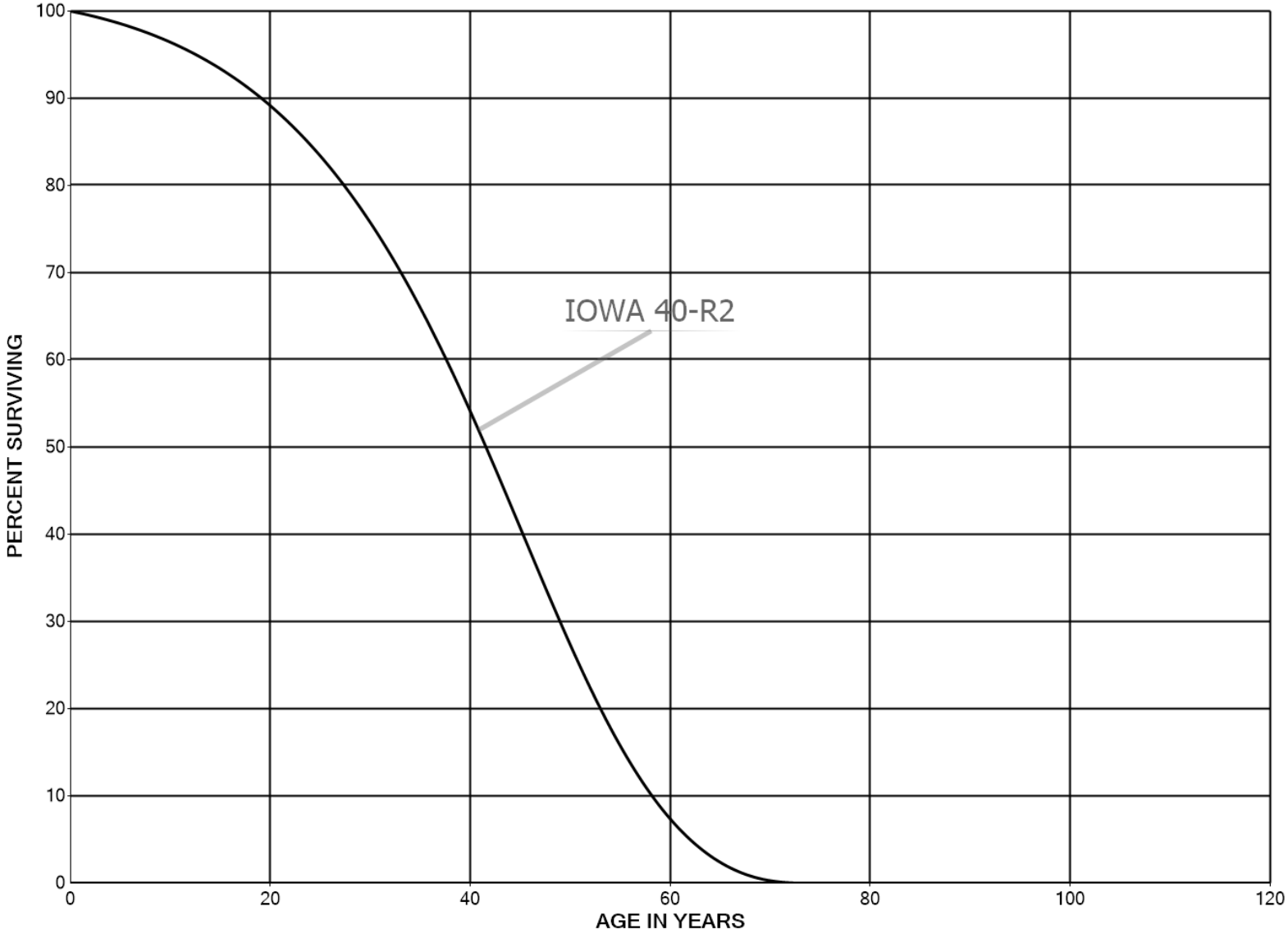
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - MAJOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

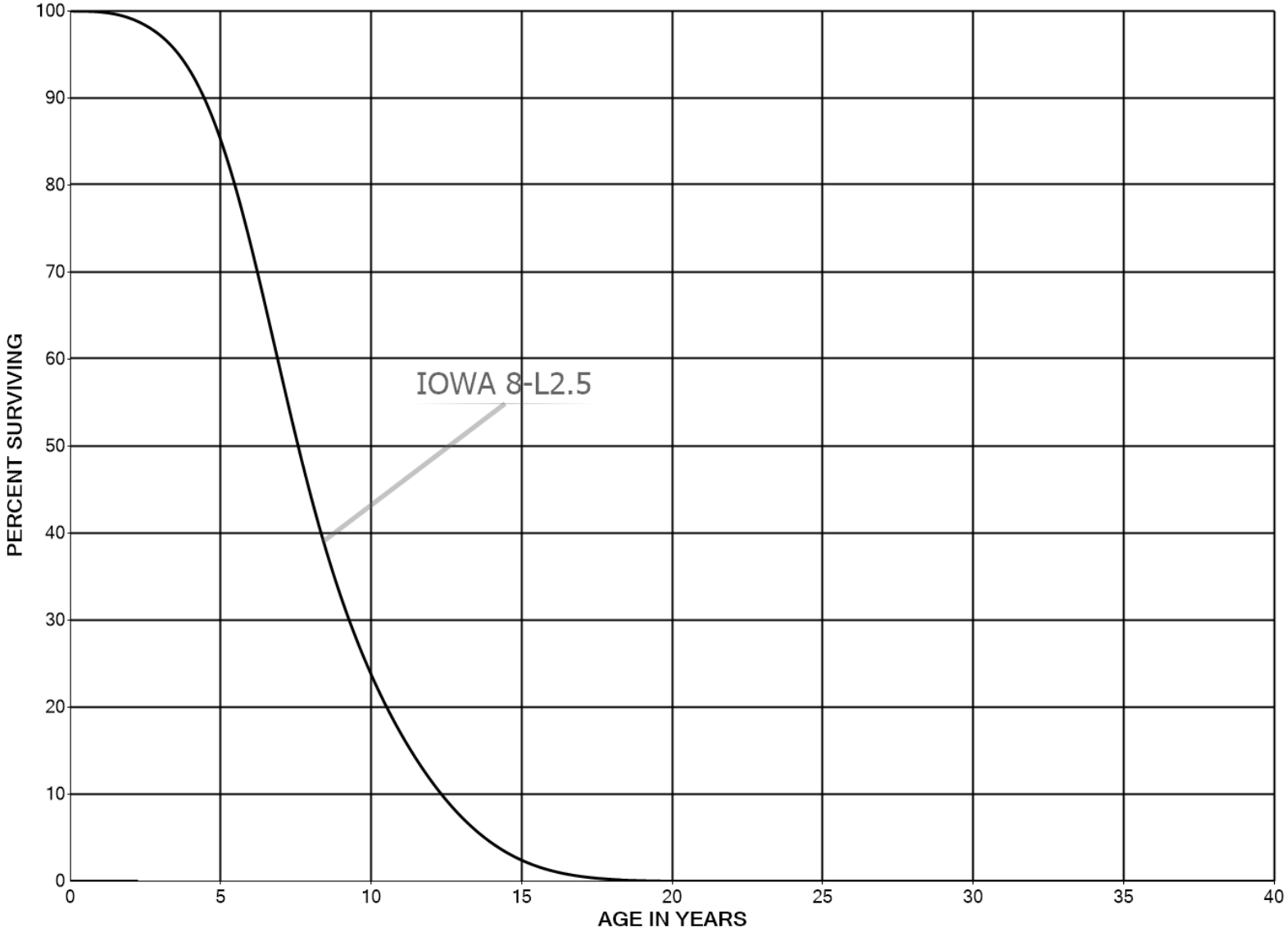
PLACEMENT BAND 1856-2022 EXPERIENCE BAND 1960-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	59,282	27,529	0.4644	0.5356	61.80
120.5	31,753		0.0000	1.0000	33.10
121.5	31,753		0.0000	1.0000	33.10
122.5	31,753		0.0000	1.0000	33.10
123.5	31,753		0.0000	1.0000	33.10
124.5	31,753		0.0000	1.0000	33.10
125.5	31,753		0.0000	1.0000	33.10
126.5	30,579		0.0000	1.0000	33.10
127.5	30,579		0.0000	1.0000	33.10
128.5	30,579		0.0000	1.0000	33.10
129.5	30,579		0.0000	1.0000	33.10
130.5	30,579	3,862	0.1263	0.8737	33.10
131.5	26,717		0.0000	1.0000	28.92
132.5	26,717		0.0000	1.0000	28.92
133.5	26,502		0.0000	1.0000	28.92
134.5	26,185		0.0000	1.0000	28.92
135.5	26,185		0.0000	1.0000	28.92
136.5	26,185		0.0000	1.0000	28.92
137.5	26,185		0.0000	1.0000	28.92
138.5	26,185	8,345	0.3187	0.6813	28.92
139.5	17,841		0.0000	1.0000	19.70
140.5	17,841		0.0000	1.0000	19.70
141.5	17,841		0.0000	1.0000	19.70
142.5	17,841		0.0000	1.0000	19.70
143.5	12,720		0.0000	1.0000	19.70
144.5	12,720		0.0000	1.0000	19.70
145.5	12,720		0.0000	1.0000	19.70
146.5	2,385		0.0000	1.0000	19.70
147.5	2,385		0.0000	1.0000	19.70
148.5	2,385		0.0000	1.0000	19.70
149.5	2,385		0.0000	1.0000	19.70
150.5	2,385		0.0000	1.0000	19.70
151.5					19.70

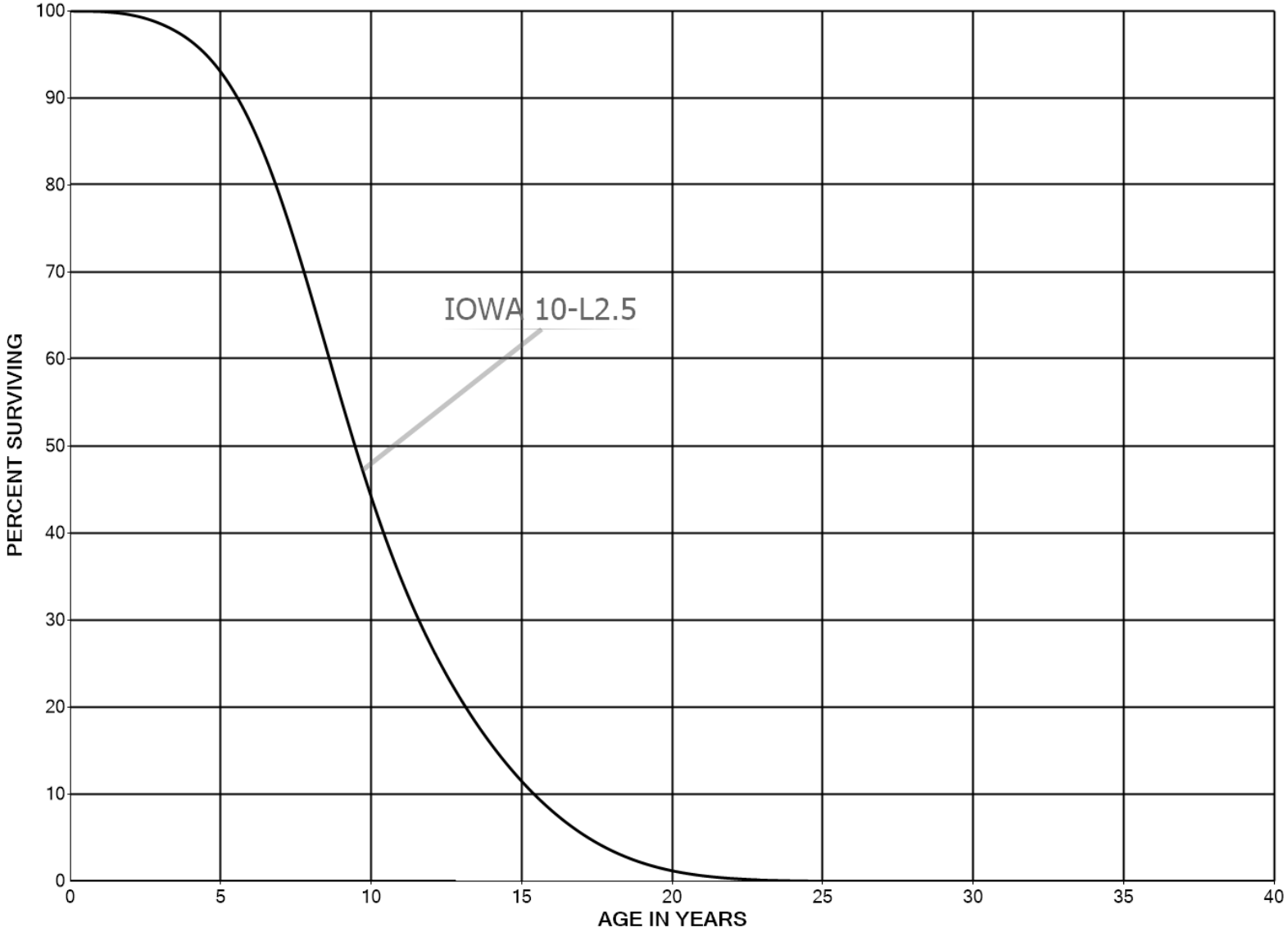
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - OTHER STRUCTURES
SMOOTH SURVIVOR CURVE



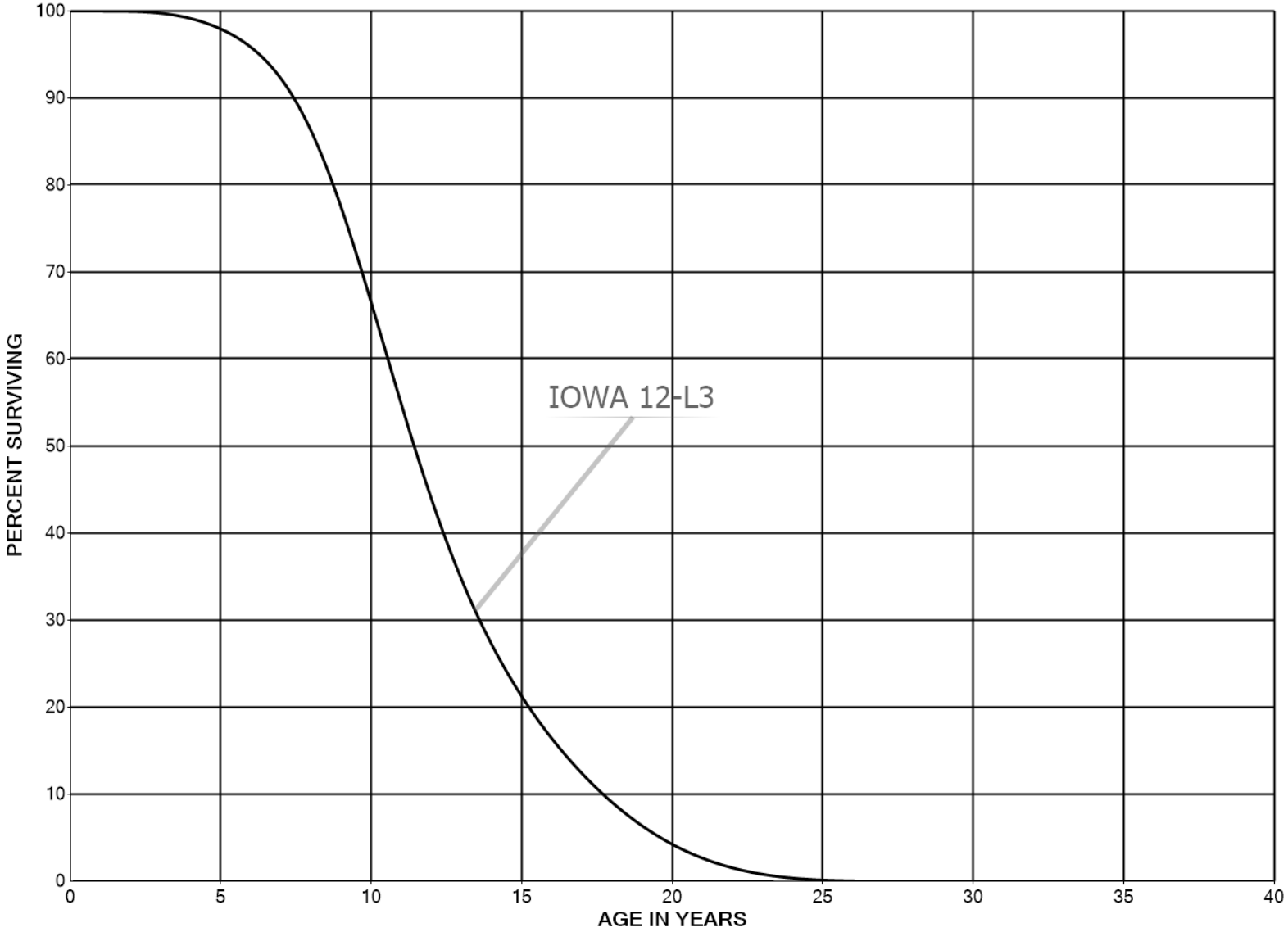
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S
SMOOTH SURVIVOR CURVE



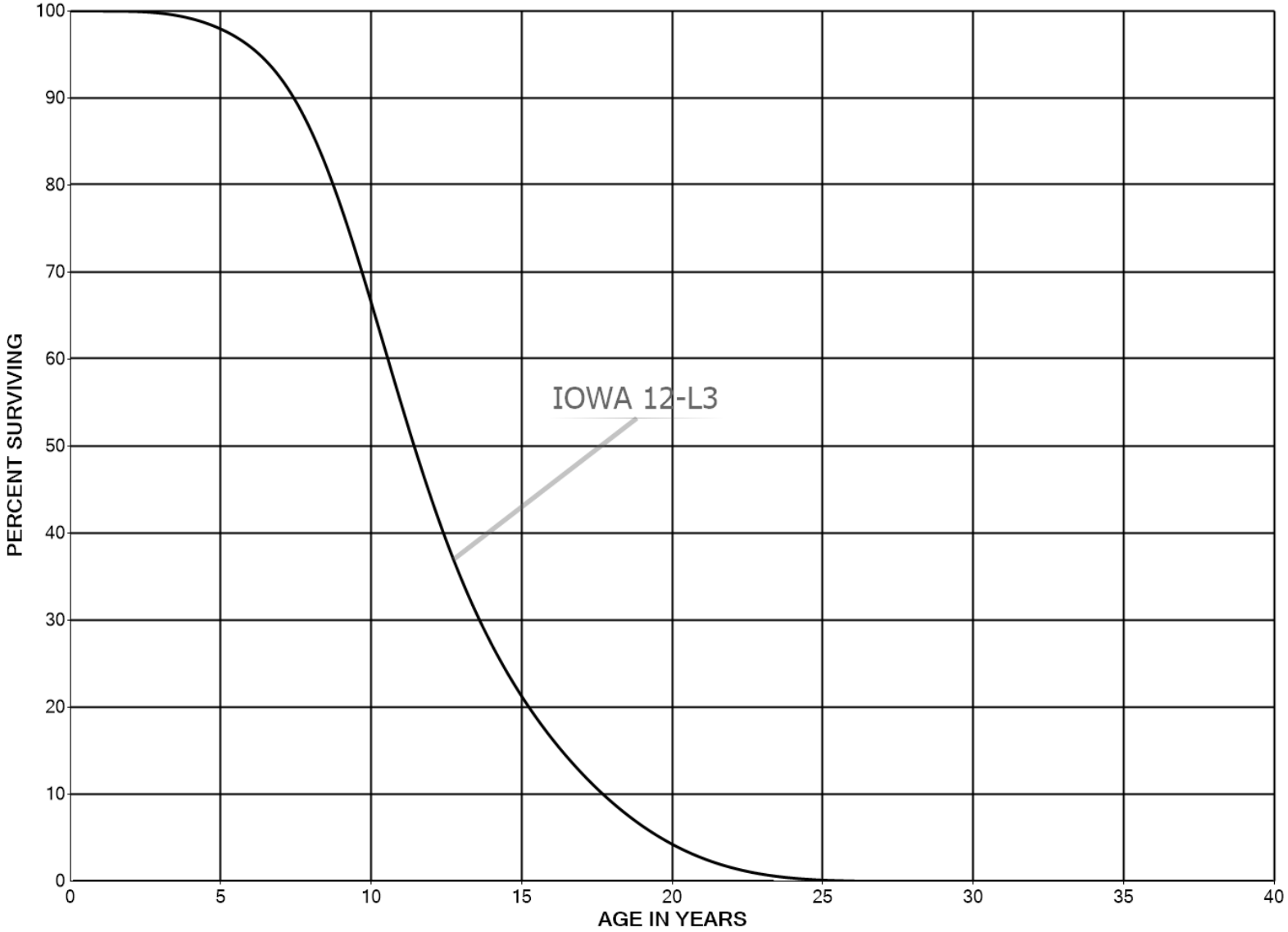
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS
SMOOTH SURVIVOR CURVE



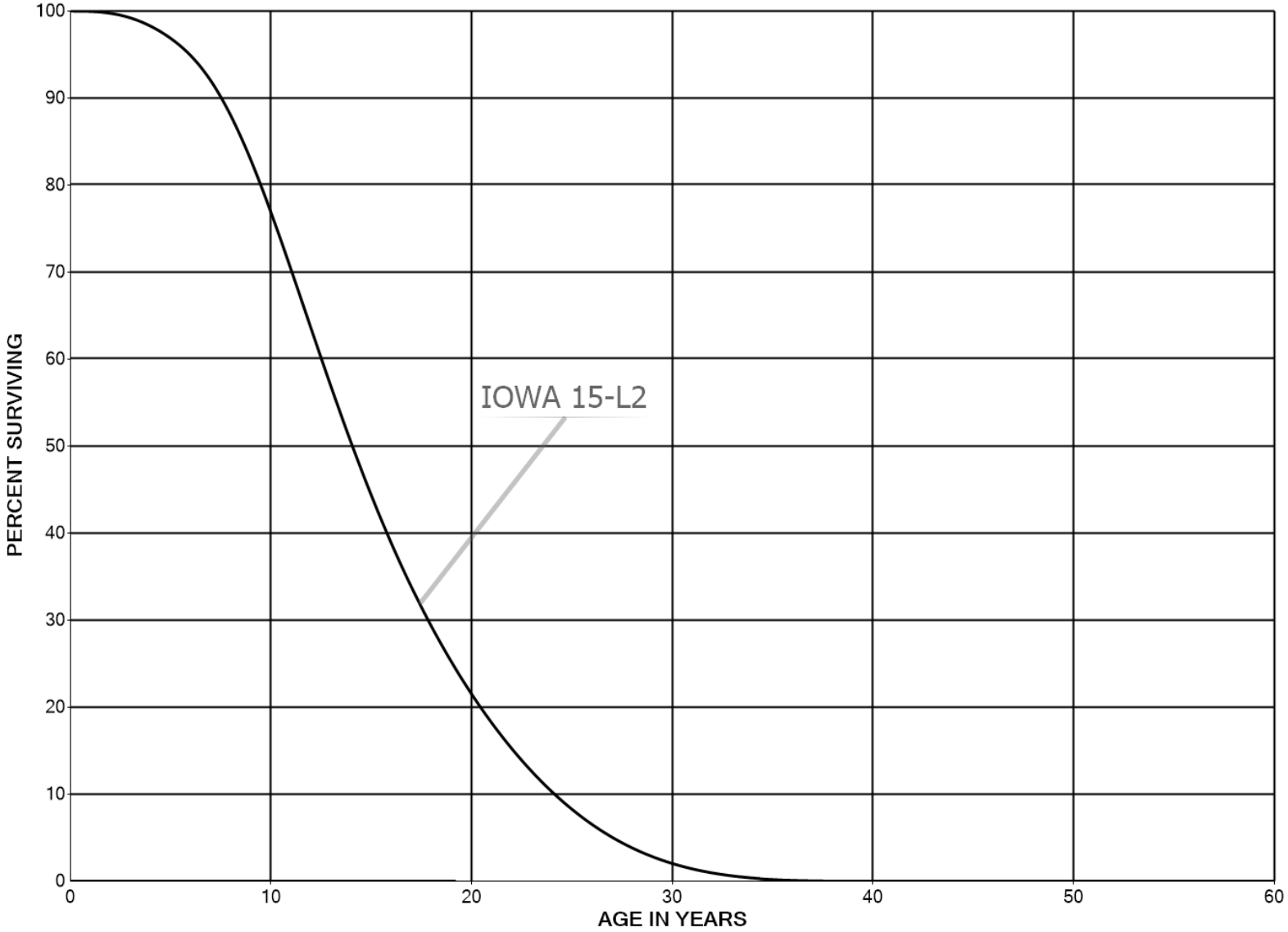
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES
SMOOTH SURVIVOR CURVE



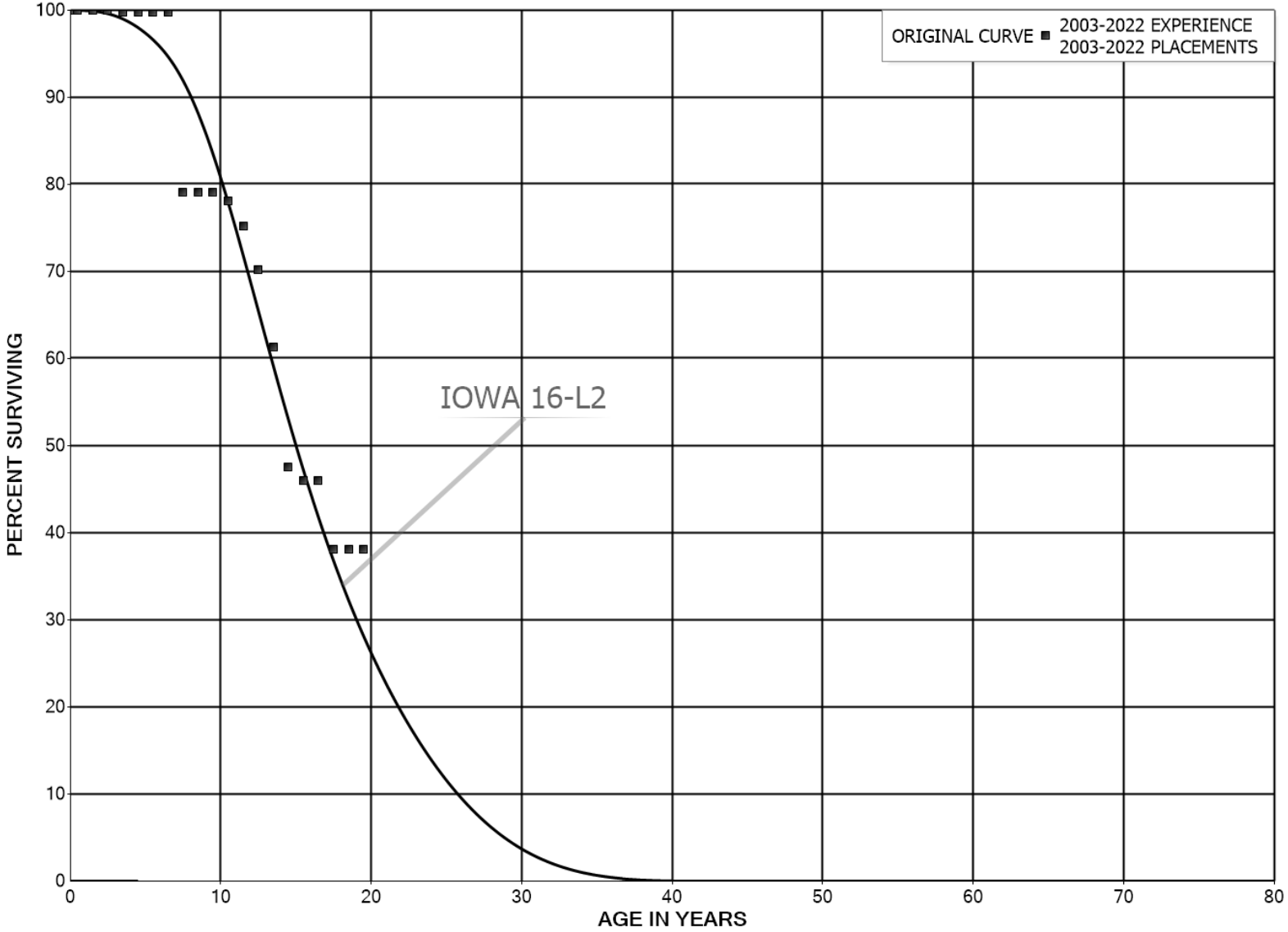
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 396 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2003-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,846,551		0.0000	1.0000	100.00
0.5	6,692,710		0.0000	1.0000	100.00
1.5	6,132,231		0.0000	1.0000	100.00
2.5	4,159,706	11,613	0.0028	0.9972	100.00
3.5	3,800,459		0.0000	1.0000	99.72
4.5	2,164,666		0.0000	1.0000	99.72
5.5	2,164,666		0.0000	1.0000	99.72
6.5	2,164,666	447,519	0.2067	0.7933	99.72
7.5	1,717,147		0.0000	1.0000	79.10
8.5	1,717,147		0.0000	1.0000	79.10
9.5	1,701,773	22,169	0.0130	0.9870	79.10
10.5	1,679,604	63,275	0.0377	0.9623	78.07
11.5	1,616,328	106,351	0.0658	0.9342	75.13
12.5	1,497,888	189,007	0.1262	0.8738	70.19
13.5	1,127,075	253,560	0.2250	0.7750	61.33
14.5	838,440	28,508	0.0340	0.9660	47.53
15.5	758,631		0.0000	1.0000	45.92
16.5	697,175	119,512	0.1714	0.8286	45.92
17.5	482,513		0.0000	1.0000	38.05
18.5	154,097		0.0000	1.0000	38.05
19.5					38.05

PART VII. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1900	71,114	71,114			0.0
1901	4,920	4,685	235	235	0.0
1902	32,146	32,068	78	313	0.0
1903	42,393	42,098	295	608	0.0
1904	13,637	12,843	794	1,402	0.0
1905	7,334	6,961	373	1,775	0.0
1906	18,263	17,473	790	2,565	0.0
1907	23,902	22,963	939	3,504	0.0
1908	33,362	31,341	2,021	5,525	0.0
1909	9,287	8,493	794	6,319	0.0
1910	22,879	21,592	1,287	7,606	0.0
1911	36,805	34,245	2,560	10,166	0.0
1912	24,366	22,481	1,885	12,051	0.0
1913	25,051	22,321	2,730	14,781	0.0
1914	60,616	53,701	6,915	21,696	0.0
1915	32,913	29,228	3,685	25,381	0.0
1916	22,274	19,585	2,689	28,070	0.0
1917	11,501	10,963	538	28,608	0.0
1918	10,458	9,880	578	29,186	0.0
1919	14,496	13,738	758	29,944	0.0
1920	15,269	14,476	793	30,737	0.0
1921	65,394	60,391	5,003	35,740	0.0
1922	78,978	74,235	4,743	40,483	0.0
1923	66,295	60,115	6,180	46,663	0.0
1924	276,812	251,627	25,185	71,848	0.0
1925	80,955	73,706	7,249	79,097	0.0
1926	359,637	316,707	42,930	122,027	0.0
1927	109,091	102,037	7,054	129,081	0.0
1928	248,214	229,200	19,014	148,095	0.0
1929	187,494	167,311	20,183	168,278	0.0
1930	387,638	330,336	57,302	225,580	0.0
1931	411,490	358,316	53,174	278,754	0.0
1932	198,577	191,883	6,694	285,448	0.0
1933	28,362	25,747	2,615	288,063	0.0
1934	24,652	22,666	1,986	290,049	0.0
1935	17,598	15,979	1,619	291,668	0.0
1936	45,134	41,591	3,543	295,211	0.0
1937	25,746	23,286	2,460	297,671	0.0
1938	16,600	14,800	1,800	299,471	0.0
1939	38,107	34,329	3,778	303,249	0.0
1940	55,611	50,362	5,249	308,498	0.0
1941	90,710	81,000	9,710	318,208	0.0
1942	38,071	32,059	6,012	324,220	0.0
1943	21,704	20,531	1,173	325,393	0.0
1944	19,400	17,311	2,089	327,482	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1945	28,676	26,257	2,419	329,901	0.0
1946	470,794	376,527	94,267	424,168	0.0
1947	138,510	119,585	18,925	443,093	0.0
1948	272,474	239,214	33,260	476,353	0.0
1949	463,524	412,525	50,999	527,352	0.0
1950	2,029,179	1,601,262	427,917	955,269	0.0
1951	760,841	642,727	118,114	1,073,383	0.0
1952	2,443,863	2,139,772	304,091	1,377,474	0.0
1953	1,463,550	1,161,736	301,814	1,679,288	0.0
1954	2,643,958	2,123,036	520,922	2,200,210	0.0
1955	2,317,292	1,887,820	429,472	2,629,682	0.1
1956	4,265,424	3,412,863	852,561	3,482,243	0.1
1957	3,808,587	2,865,490	943,097	4,425,340	0.1
1958	3,777,558	2,757,621	1,019,937	5,445,277	0.1
1959	3,960,625	2,977,199	983,426	6,428,703	0.1
1960	4,934,020	3,669,694	1,264,326	7,693,029	0.2
1961	4,275,807	3,206,044	1,069,763	8,762,792	0.2
1962	4,151,956	3,059,910	1,092,046	9,854,838	0.2
1963	5,537,723	3,975,076	1,562,647	11,417,485	0.3
1964	7,065,342	5,040,597	2,024,745	13,442,230	0.3
1965	7,671,680	5,526,789	2,144,891	15,587,121	0.4
1966	8,527,501	6,171,834	2,355,667	17,942,788	0.4
1967	7,965,415	5,632,509	2,332,906	20,275,694	0.5
1968	10,357,531	7,244,528	3,113,003	23,388,697	0.5
1969	11,051,639	7,701,862	3,349,777	26,738,474	0.6
1970	10,144,673	7,095,158	3,049,515	29,787,989	0.7
1971	9,248,166	6,413,302	2,834,864	32,622,853	0.7
1972	10,711,354	7,277,419	3,433,935	36,056,788	0.8
1973	8,840,403	6,067,017	2,773,386	38,830,174	0.9
1974	10,299,090	7,309,905	2,989,185	41,819,359	0.9
1975	8,299,219	5,631,113	2,668,106	44,487,465	1.0
1976	7,991,754	5,483,417	2,508,337	46,995,802	1.1
1977	10,108,475	6,752,622	3,355,853	50,351,655	1.1
1978	9,725,518	6,321,316	3,404,202	53,755,857	1.2
1979	14,704,704	9,382,245	5,322,459	59,078,316	1.3
1980	24,712,267	15,795,511	8,916,756	67,995,072	1.5
1981	25,511,249	16,162,075	9,349,174	77,344,246	1.8
1982	25,078,451	16,542,212	8,536,239	85,880,485	1.9
1983	13,073,780	8,946,738	4,127,042	90,007,527	2.0
1984	17,741,579	11,889,592	5,851,987	95,859,514	2.2
1985	21,455,778	14,293,333	7,162,445	103,021,959	2.3
1986	26,157,625	16,874,650	9,282,975	112,304,934	2.5
1987	29,136,673	18,670,736	10,465,937	122,770,871	2.8
1988	41,599,787	25,795,500	15,804,287	138,575,158	3.1
1989	44,676,695	27,484,447	17,192,248	155,767,406	3.5

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1990	48,364,281	29,420,915	18,943,366	174,710,772	4.0
1991	39,344,774	23,685,733	15,659,041	190,369,813	4.3
1992	42,203,089	25,454,262	16,748,827	207,118,640	4.7
1993	32,404,273	19,431,679	12,972,594	220,091,234	5.0
1994	49,444,996	28,934,436	20,510,560	240,601,794	5.5
1995	57,730,206	31,276,972	26,453,234	267,055,028	6.1
1996	61,193,392	32,219,847	28,973,545	296,028,573	6.7
1997	74,640,299	39,123,994	35,516,305	331,544,878	7.5
1998	58,246,789	29,958,729	28,288,060	359,832,938	8.2
1999	44,610,162	22,524,848	22,085,314	381,918,252	8.7
2000	61,432,849	29,616,524	31,816,325	413,734,577	9.4
2001	56,783,065	26,805,460	29,977,605	443,712,182	10.1
2002	55,899,582	26,746,183	29,153,399	472,865,581	10.7
2003	56,219,734	25,189,948	31,029,786	503,895,367	11.4
2004	73,075,292	32,840,715	40,234,577	544,129,944	12.4
2005	65,033,987	26,979,827	38,054,160	582,184,104	13.2
2006	63,325,543	26,196,853	37,128,690	619,312,794	14.1
2007	65,265,282	27,282,776	37,982,506	657,295,300	14.9
2008	67,115,065	26,528,477	40,586,588	697,881,888	15.8
2009	65,679,627	24,165,652	41,513,975	739,395,863	16.8
2010	58,425,742	20,215,339	38,210,403	777,606,266	17.7
2011	86,462,787	28,603,575	57,859,212	835,465,478	19.0
2012	107,154,401	33,393,952	73,760,449	909,225,927	20.6
2013	122,023,218	35,085,904	86,937,314	996,163,241	22.6
2014	155,872,502	41,787,622	114,084,880	1,110,248,121	25.2
2015	180,057,164	44,134,328	135,922,836	1,246,170,957	28.3
2016	199,364,484	44,737,662	154,626,822	1,400,797,779	31.8
2017	202,492,677	41,530,772	160,961,905	1,561,759,684	35.5
2018	290,308,052	54,142,607	236,165,445	1,797,925,129	40.8
2019	264,907,800	48,037,422	216,870,378	2,014,795,507	45.7
2020	268,713,967	46,440,940	222,273,027	2,237,068,534	50.8
2021	353,093,139	47,474,263	305,618,876	2,542,687,410	57.7
2022	414,890,063	48,587,692	366,302,371	2,908,989,781	66.0
2023	481,690,495	52,394,839	429,295,656	3,338,285,437	75.8
2024	339,686,046	23,661,220	316,024,826	3,654,310,263	83.0
2025	340,749,674	15,116,943	325,632,731	3,979,942,994	90.4
2026	431,487,531	6,832,898	424,654,633	4,404,597,627	100.0
TOTAL	5,908,417,994	1,503,820,367	4,404,597,627		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2019	33,513,297	7,271,585	26,241,712	26,241,712	51.0
2020	1,957,793	356,188	1,601,605	27,843,317	54.1
2021	658,288	104,441	553,847	28,397,164	55.2
2022	4,218,639	706,437	3,512,202	31,909,366	62.0
2023	11,849,883	1,218,558	10,631,325	42,540,691	82.7
2024	8,704,747	676,712	8,028,035	50,568,726	98.3
2025	532,025	36,850	495,175	51,063,901	99.2
2026	404,752	8,398	396,354	51,460,255	100.0
TOTAL	61,839,424	10,379,169	51,460,255		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2016	1,993,990	1,373,263	620,727	620,727	0.4
2017	77,995,129	49,268,971	28,726,158	29,346,885	20.4
2018	1,514,039	1,237,504	276,535	29,623,420	20.6
2019	62,845,437	33,176,097	29,669,340	59,292,760	41.2
2020	12,398,870	8,063,834	4,335,036	63,627,796	44.2
2021	14,497,517	6,648,707	7,848,810	71,476,606	49.7
2022	12,009,214	6,173,616	5,835,598	77,312,204	53.7
2023	11,916,735	5,359,252	6,557,483	83,869,687	58.3
2024	10,696,947	4,070,194	6,626,753	90,496,440	62.9
2025	9,424,412	2,083,665	7,340,747	97,837,187	68.0
2026	48,545,652	2,428,659	46,116,993	143,954,180	100.0
TOTAL	263,837,942	119,883,762	143,954,180		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1902	3,610.27	3,610	3,610			
1903	4,110.54	4,111	4,111			
1908	44.05	44	44			
1910	85.13	85	85			
1912	835.22	835	835			
1913	222.36	222	222			
1914	14.50	14	15			
1915	224.10	224	224			
1916	117.50	118	118			
1917	64.30	64	64			
1926	6,471.58	6,347	6,472			
1929	1,806.23	1,754	1,803	3	2.01	1
1930	2,041.31	1,976	2,031	10	2.23	4
1931	27,123.22	26,166	26,895	229	2.47	93
1932	2,640.53	2,539	2,610	31	2.70	11
1933	538.99	516	530	9	2.95	3
1934	812.94	776	798	15	3.20	5
1935	12.64	12	12			
1937	203.24	192	197	6	3.96	2
1938	375.47	353	363	13	4.22	3
1939	962.92	901	926	37	4.49	8
1940	6,450.60	6,013	6,180	270	4.75	57
1941	592.71	550	565	27	5.02	5
1942	337.44	312	321	17	5.30	3
1943	60.01	55	57	3	5.58	1
1944	422.25	387	398	24	5.86	4
1945	631.09	576	592	39	6.15	6
1946	3,351.10	3,043	3,128	223	6.44	35
1947	2,508.33	2,266	2,329	179	6.75	27
1948	4,635.54	4,167	4,283	353	7.07	50
1949	1,157.34	1,035	1,064	94	7.39	13
1950	190.65	170	175	16	7.73	2
1951	4,042.41	3,575	3,675	368	8.09	45
1952	198.20	174	179	19	8.46	2
1953	5,400.53	4,718	4,849	551	8.85	62
1954	14,353.89	12,457	12,804	1,550	9.25	168
1955	8,390.67	7,230	7,431	959	9.68	99
1956	78,471.52	67,116	68,985	9,487	10.13	937
1957	2,231.51	1,894	1,947	285	10.60	27
1958	3,854.85	3,244	3,334	521	11.10	47
1959	3,405.26	2,840	2,919	486	11.61	42

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	11,197.19	9,254	9,512	1,686	12.15	139
1961	2,660.99	2,177	2,238	423	12.72	33
1962	3,222.41	2,610	2,683	540	13.30	41
1963	3,157.03	2,530	2,600	557	13.91	40
1964	5,365.41	4,251	4,369	996	14.54	69
1965	6,572.95	5,148	5,291	1,282	15.18	84
1966	36,334.10	28,118	28,901	7,433	15.83	470
1967	22,318.73	17,058	17,533	4,786	16.50	290
1968	3,796.90	2,865	2,945	852	17.18	50
1969	12,470.57	9,287	9,546	2,925	17.87	164
1970	18,015.96	13,237	13,606	4,410	18.57	237
1971	1,199.64	869	893	306	19.28	16
1972	11,935.28	8,525	8,762	3,173	20.00	159
1973	5,080.37	3,577	3,677	1,404	20.72	68
1974	8,346.12	5,787	5,948	2,398	21.46	112
1975	11,480.98	7,838	8,056	3,425	22.21	154
1976	7,995.15	5,370	5,520	2,476	22.98	108
1977	11,905.30	7,866	8,085	3,820	23.75	161
1978	12,918.41	8,391	8,625	4,294	24.53	175
1979	7,570.24	4,832	4,967	2,604	25.32	103
1980	4,856.13	3,043	3,128	1,728	26.13	66
1981	73,749.17	45,366	46,629	27,120	26.94	1,007
1982	10,050.64	6,360	6,537	3,514	25.68	137
1983	9,041.47	5,631	5,788	3,254	26.19	124
1984	15,250.78	9,279	9,537	5,713	27.19	210
1985	26,754.50	16,002	16,448	10,307	27.72	372
1986	14,112.19	8,236	8,465	5,647	28.72	197
1987	3,342.10	1,902	1,955	1,387	29.72	47
1988	11,301.63	6,311	6,487	4,815	30.25	159
1989	1,090.00	593	610	480	31.25	15
1990	8,000.14	4,263	4,382	3,618	31.78	114
1991	117,309.04	60,790	62,482	54,827	32.78	1,673
1992	25,030.74	12,603	12,954	12,077	33.78	358
1993	12,460.42	6,132	6,303	6,158	34.32	179
1994	6,889.97	3,289	3,381	3,509	35.32	99
1995	12,673.77	5,862	6,025	6,649	36.32	183
1996	12,902.15	5,815	5,977	6,925	36.87	188
1997	66,170.17	28,837	29,640	36,530	37.87	965
1998	16,023.55	6,744	6,932	9,092	38.87	234
1999	3,898.06	1,583	1,627	2,271	39.87	57
2000	5,089.04	1,990	2,045	3,044	40.87	74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2001	2,659.41	1,007	1,035	1,624	41.41	39
2002	551.45	201	207	345	42.41	8
2003	1,306.89	456	469	838	43.41	19
2004	373.65	125	128	245	44.41	6
2007	10,611.38	3,085	3,171	7,440	46.97	158
2024	114.45	4	4	110	63.29	2
	868,159.56	567,780	583,277	284,883		11,125

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.6 1.28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
1915	44.03	44	44			
1931	22.41	22	22			
1936	428.90	429	429			
1939	2,662.19	2,662	2,662			
1940	342.66	343	343			
1946	195.14	195	195			
1953	97.16	97	97			
1954	398.72	399	399			
1955	1,082.26	1,082	1,082			
1956	2,295.78	2,296	2,296			
1957	310.18	310	310			
1958	2,058.46	2,058	2,058			
1959	300.33	300	300			
1960	6,541.37	6,541	6,541			
1961	4,353.35	4,353	4,353			
1962	2,282.71	2,283	2,283			
1963	736.08	736	736			
1964	190.55	191	191			
1965	2,343.06	2,343	2,343			
1966	2,250.24	2,249	2,250			
1967	9,977.71	9,861	9,978			
1968	2,151.32	2,103	2,151			
1969	544.69	526	545			
1970	40.03	38	40			
1971	1,214.19	1,146	1,214			
1973	700.59	647	701			
1974	4,750.87	4,342	4,751			
1977	193.66	171	194			
1978	2,207.46	1,928	2,207			
1979	2,203.60	1,901	2,204			
1983	5,281.99	4,729	5,282			
1984	369.17	326	369			
1985	9,821.44	8,589	9,821			
1986	241.46	209	241			
1987	1,014.54	872	1,015			
1988	31,015.80	26,339	31,016			
1989	44,844.88	37,584	44,845			
1994	601.90	470	602			
1996	1,215.58	919	1,216			
1998	1,575.63	1,148	1,576			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	1,112	1,760			
2019	11,416.29	3,297	6,257	5,160	18.47	279
2020	138.01	36	68	70	18.69	4
	162,216.47	137,226	156,987	5,229		283

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.5 0.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1900	71,113.66	67,852	71,114			
1902	24,056.23	22,780	24,056			
1903	33,197.34	31,316	33,197			
1904	1,964.62	1,846	1,965			
1906	2,420.69	2,259	2,421			
1907	8,730.25	8,121	8,730			
1910	749.15	690	749			
1913	1,738.46	1,586	1,738			
1915	63.32	57	63			
1922	35.55	31	36			
1925	1,356.81	1,189	1,357			
1926	46,464.38	40,560	46,464			
1927	2,171.63	1,888	2,172			
1928	180.25	156	180			
1929	27,529.19	23,756	27,529			
1930	2,522.76	2,168	2,523			
1931	296.56	254	297			
1932	122,819.26	104,691	122,819			
1933	4,897.35	4,156	4,897			
1934	10,855.44	9,172	10,855			
1935	1,410.95	1,187	1,411			
1936	16,622.35	13,916	16,622			
1937	2,388.88	1,990	2,389			
1938	2,797.65	2,319	2,798			
1939	797.65	658	798			
1940	11,364.66	9,322	11,365			
1941	11,633.51	9,490	11,634			
1942	1,215.69	986	1,213	3	14.17	
1943	5,838.88	4,708	5,791	47	14.53	3
1944	48.34	39	48			
1945	1,498.10	1,193	1,468	31	15.28	2
1946	4,905.03	3,880	4,773	132	15.67	8
1947	24,941.60	19,594	24,103	838	16.08	52
1948	98,837.20	77,106	94,851	3,987	16.49	242
1949	28,199.11	21,837	26,862	1,337	16.92	79
1950	2,735.68	2,102	2,586	150	17.36	9
1951	202,177.37	154,166	189,645	12,533	17.81	704
1952	22,207.66	16,798	20,664	1,544	18.27	85
1953	200,020.82	150,042	184,571	15,449	18.74	824
1954	797,823.90	593,262	729,791	68,033	19.23	3,538
1955	81,749.31	60,255	74,122	7,628	19.72	387

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1956	1,473,781.22	1,076,258	1,323,939	149,842	20.23	7,407
1957	311,182.44	225,088	276,888	34,294	20.75	1,653
1958	299,804.72	214,741	264,160	35,645	21.28	1,675
1959	613,382.04	434,931	535,023	78,359	21.82	3,591
1960	674,919.59	473,524	582,497	92,423	22.38	4,130
1961	47,891.52	33,243	40,893	6,998	22.94	305
1962	190,718.09	130,934	161,066	29,652	23.51	1,261
1963	122,060.87	82,839	101,903	20,158	24.10	836
1964	290,969.66	195,182	240,100	50,870	24.69	2,060
1965	701,420.51	464,902	571,891	129,530	25.29	5,122
1966	742,304.44	485,861	597,673	144,631	25.91	5,582
1967	215,827.53	139,483	171,583	44,245	26.53	1,668
1968	370,389.64	236,260	290,631	79,759	27.16	2,937
1969	640,487.71	403,078	495,839	144,649	27.80	5,203
1970	874,219.01	542,602	667,472	206,747	28.45	7,267
1971	453,818.02	277,678	341,581	112,237	29.11	3,856
1972	966,536.05	582,754	716,864	249,672	29.78	8,384
1973	372,161.96	221,064	271,938	100,224	30.45	3,291
1974	485,847.07	284,123	349,509	136,338	31.14	4,378
1975	297,092.08	171,006	210,360	86,732	31.83	2,725
1976	137,471.87	77,864	95,783	41,689	32.52	1,282
1977	134,299.99	74,796	92,009	42,291	33.23	1,273
1978	287,058.05	157,156	193,323	93,735	33.94	2,762
1979	501,981.46	270,001	332,137	169,845	34.66	4,900
1980	243,613.68	128,660	158,269	85,345	35.39	2,412
1981	283,711.51	147,039	180,877	102,834	36.13	2,846
1982	319,398.12	183,718	225,997	93,401	32.68	2,858
1983	524,887.81	297,401	365,842	159,045	33.08	4,808
1984	749,802.45	418,165	514,398	235,404	33.51	7,025
1985	455,843.70	248,207	305,327	150,516	34.51	4,362
1986	565,064.08	302,479	372,089	192,975	34.94	5,523
1987	414,536.27	218,046	268,225	146,311	35.37	4,137
1988	491,903.15	252,150	310,178	181,725	36.37	4,997
1989	207,476.32	104,340	128,352	79,124	36.82	2,149
1990	360,151.18	177,555	218,416	141,735	37.28	3,802
1991	2,298,208.76	1,101,761	1,355,311	942,897	38.28	24,632
1992	1,177,930.89	552,685	679,876	498,055	38.74	12,856
1993	1,136,543.85	521,446	641,447	495,096	39.22	12,624
1994	971,986.45	432,534	532,074	439,913	40.22	10,938
1995	571,362.11	248,200	305,319	266,043	40.69	6,538
1996	804,324.21	340,631	419,021	385,303	41.18	9,357

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1997	1,997,584.37	818,011	1,006,262	991,323	42.18	23,502
1998	1,718,962.57	684,663	842,226	876,737	42.67	20,547
1999	1,080,765.90	418,256	514,510	566,256	43.17	13,117
2000	2,093,639.95	785,952	966,825	1,126,815	43.68	25,797
2001	940,486.78	339,610	417,765	522,722	44.68	11,699
2002	1,450,386.34	506,475	623,031	827,355	45.19	18,308
2003	537,154.95	181,075	222,746	314,409	45.72	6,877
2004	239,158.46	77,153	94,908	144,250	46.72	3,088
2005	237,738.75	73,747	90,719	147,020	47.25	3,112
2006	169,927.36	50,587	62,229	107,699	47.78	2,254
2007	509,991.81	145,297	178,734	331,257	48.32	6,855
2008	103,422.99	28,317	34,834	68,589	49.07	1,398
2009	74,105.67	19,327	23,775	50,331	49.61	1,015
2010	158,384.81	39,200	48,221	110,164	50.17	2,196
2011	140,623.77	32,906	40,479	100,145	50.73	1,974
2012	2,357,530.59	516,299	635,116	1,722,415	51.72	33,303
2013	41,989.81	8,616	10,599	31,391	52.29	600
2024	307,730.46	12,925	15,899	291,831	57.02	5,118
2025	643,848.72	16,611	20,434	623,415	56.64	11,007
	39,468,181.38	19,154,790	23,526,057	15,942,124		403,112

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.5 1.02

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1927	43.41	43	43			
1935	1.00	1	1			
1937	63.36	63	63			
1938	130.20	128	130			
1939	199.99	196	200			
1940	188.95	184	189			
1942	115.52	111	116			
1943	207.70	199	208			
1944	83.77	80	84			
1945	174.42	165	174			
1946	163.63	154	164			
1947	277.29	260	277			
1948	89.09	83	89			
1950	7.97	7	8			
1952	18.79	17	19			
1953	5,944.35	5,406	5,944			
1954	8,508.82	7,700	8,509			
1955	7,542.08	6,789	7,542			
1956	39,702.37	35,562	39,702			
1957	13,574.54	12,095	13,575			
1958	6,469.06	5,734	6,469			
1959	9,801.88	8,640	9,802			
1960	24,067.26	21,100	24,067			
1961	5,498.45	4,793	5,492	7	6.29	1
1962	12,455.03	10,793	12,367	88	6.54	13
1963	5,203.12	4,482	5,136	68	6.79	10
1964	19,172.75	16,414	18,807	365	7.05	52
1965	16,408.17	13,957	15,992	416	7.32	57
1966	43,116.46	36,429	41,741	1,375	7.60	181
1967	18,626.28	15,627	17,906	721	7.89	91
1968	18,055.59	15,038	17,231	825	8.19	101
1969	32,278.33	26,673	30,562	1,716	8.51	202
1970	15,250.12	12,499	14,322	929	8.84	105
1971	26,308.31	21,379	24,496	1,812	9.18	197
1972	26,694.33	21,497	24,632	2,063	9.54	216
1973	12,036.90	9,600	11,000	1,037	9.92	105
1974	18,632.52	14,712	16,857	1,775	10.31	172
1975	30,467.80	23,802	27,273	3,195	10.72	298
1976	138,678.97	107,123	122,743	15,935	11.15	1,429
1977	14,832.80	11,324	12,975	1,858	11.59	160
1978	22,161.07	16,707	19,143	3,018	12.06	250

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1979	41,008.38	30,514	34,963	6,045	12.54	482
1980	13,577.55	9,964	11,417	2,161	13.04	166
1981	82,437.31	59,641	68,338	14,100	13.55	1,041
1982	156,832.69	121,451	139,161	17,672	12.89	1,371
1983	24,048.18	18,409	21,093	2,955	13.25	223
1984	50,677.87	38,328	43,917	6,761	13.61	497
1985	86,879.75	64,508	73,914	12,965	14.31	906
1986	86,985.91	63,726	73,018	13,967	14.69	951
1987	52,185.49	37,688	43,184	9,002	15.10	596
1988	411,643.09	291,279	333,753	77,890	15.81	4,927
1989	41,658.60	29,019	33,250	8,408	16.22	518
1990	297,917.74	203,031	232,637	65,281	16.94	3,854
1991	147,610.27	98,869	113,286	34,324	17.38	1,975
1992	264,883.76	173,287	198,555	66,328	18.10	3,665
1993	163,266.69	104,768	120,045	43,222	18.56	2,329
1994	349,935.44	220,074	252,165	97,771	19.03	5,138
1995	117,235.62	71,807	82,278	34,958	19.77	1,768
1996	215,121.50	128,858	147,648	67,474	20.25	3,332
1997	728,580.35	424,107	485,950	242,631	21.00	11,554
1998	560,594.04	318,305	364,720	195,874	21.50	9,110
1999	16,725.51	9,206	10,548	6,177	22.26	277
2000	174,732.10	93,569	107,213	67,519	22.77	2,965
2001	495,273.00	256,353	293,734	201,539	23.53	8,565
2002	154,135.03	77,376	88,659	65,476	24.06	2,721
2003	301,200.83	145,661	166,901	134,300	24.83	5,409
2004	59,852.58	27,963	32,041	27,812	25.37	1,096
2005	86,161.34	38,816	44,476	41,685	25.92	1,608
2006	82,235.60	35,468	40,640	41,596	26.70	1,558
2007	11,729.27	4,855	5,563	6,166	27.26	226
2008	249,781.89	99,813	114,368	135,414	27.80	4,871
2012	21,662.45	7,006	8,028	13,635	30.34	449
2013	8,571.24	2,592	2,970	5,601	31.14	180
2021	1,310.54	174	199	1,111	35.99	31
2022	23,129.77	2,540	2,910	20,219	36.48	554
	6,172,833.83	3,796,591	4,347,592	1,825,242		88,553

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.6 1.43

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1955	5,466.25	5,466	5,466			
1965	7,727.57	7,728	7,728			
1966	1,743.15	1,743	1,743			
1967	249.76	250	250			
1968	2,500.34	2,500	2,500			
1972	1,946.45	1,946	1,946			
1979	706.12	706	706			
1982	5,572.11	5,474	5,572			
1983	1,354.71	1,318	1,355			
1984	2,338.50	2,243	2,339			
1985	8,363.40	7,935	8,363			
1986	1,865.01	1,756	1,865			
1987	8,236.27	7,661	8,236			
1988	56,812.32	52,154	56,812			
1989	6,202.17	5,637	6,202			
1990	81,477.96	73,249	81,478			
1991	19,398.63	17,232	19,399			
1992	11,826.34	10,369	11,826			
1993	4,988.84	4,313	4,989			
1994	24,237.82	20,714	24,238			
1995	53,971.10	45,541	53,971			
1996	2,814.71	2,333	2,815			
1997	270.53	221	271			
2000	83,012.05	64,285	79,716	3,296	7.65	431
2001	21,876.59	16,626	20,617	1,260	7.97	158
2004	19,336.59	13,768	17,073	2,264	9.00	252
2009	679,443.48	420,915	521,949	157,494	10.75	14,651
2010	158,522.71	94,686	117,414	41,109	11.12	3,697
2011	574,467.00	329,457	408,538	165,929	11.53	14,391
2012	649,682.90	357,975	443,902	205,781	11.82	17,410
2013	552,258.31	290,046	359,667	192,591	12.21	15,773
2014	229,452.61	114,726	142,264	87,188	12.50	6,975
2015	208,014.12	98,557	122,214	85,800	12.77	6,719
2022	19,067.98	4,675	5,797	13,271	13.85	958
	3,505,204.40	2,084,205	2,549,221	955,983		81,415

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.7 2.32

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1931	73.41	73	73			
1932	22.79	23	23			
1934	159.65	160	160			
1935	148.67	149	149			
1937	75.60	76	76			
1938	348.00	348	348			
1952	193.45	193	193			
1956	802.14	802	802			
1958	54.05	54	54			
1959	1,630.62	1,631	1,631			
1962	268.78	267	269			
1964	542.39	531	542			
1965	237.71	231	238			
1966	1,610.42	1,553	1,610			
1967	1,046.31	1,001	1,046			
1968	8,185.23	7,767	8,185			
1969	1,294.81	1,219	1,295			
1970	2,302.48	2,151	2,302			
1971	4,402.26	4,084	4,402			
1972	6,378.34	5,875	6,378			
1973	2,116.13	1,937	2,116			
1974	772.96	703	773			
1975	728.51	658	729			
1976	666.84	598	667			
1977	2,372.22	2,111	2,367	6	3.86	2
1978	395.78	349	391	5	4.10	1
1979	1,489.70	1,305	1,463	27	4.34	6
1980	1,156.83	1,005	1,127	30	4.58	7
1981	1,410.00	1,215	1,362	48	4.83	10
1982	4,310.08	3,891	4,310			
1983	3,348.16	2,998	3,348			
1984	3,634.15	3,224	3,617	17	5.37	3
1985	5,292.73	4,672	5,242	51	5.48	9
1986	1,466.52	1,281	1,437	29	5.83	5
1987	1,617.48	1,397	1,567	50	6.20	8
1988	7,215.84	6,183	6,937	279	6.39	44
1989	11,462.74	9,693	10,875	588	6.80	86
1990	14,888.28	12,414	13,928	960	7.23	133
1991	14,350.24	11,836	13,279	1,071	7.49	143
1992	10,561.54	8,573	9,618	943	7.95	119

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1993	9,905.10	7,904	8,868	1,037	8.42	123
1994	3,879.74	3,053	3,425	454	8.73	52
1995	7,818.56	6,035	6,771	1,048	9.23	114
	140,637.24	121,223	133,995	6,642		865
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.7	0.62

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1982	15,664.23	15,664	15,664			
1983	11,125.29	11,125	11,125			
1985	4,384.63	4,385	4,385			
1986	38,021.86	38,022	38,022			
1990	11,962.90	11,963	11,963			
1991	2,199.99	2,200	2,200			
1992	1,383.30	1,336	1,383			
1995	24,385.78	24,005	24,386			
1996	494.25	483	494			
2015	100,388.74	57,603	62,806	37,583	8.54	4,401
	210,010.97	166,786	172,428	37,583		4,401

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 2.10

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1903	298.00	295	298			
1904	222.17	219	222			
1929	410.41	370	410			
1930	548.08	492	548			
1931	10,677.87	9,552	10,675	3	7.91	
1932	38.71	34	38	1	8.18	
1933	55.00	49	55			
1934	123.52	109	122	2	8.75	
1935	533.10	469	524	9	9.04	1
1936	100.54	88	98	2	9.34	
1937	223.29	195	218	5	9.65	1
1938	178.56	155	173	5	9.96	1
1939	285.78	247	276	10	10.28	1
1940	249.96	215	240	10	10.62	1
1941	57.82	49	55	3	10.96	
1942	19.44	17	19			
1944	36.92	31	35	2	12.05	
1945	59.80	50	56	4	12.44	
1946	160.11	133	149	11	12.84	1
1947	235.63	194	217	19	13.25	1
1948	51.03	42	47	4	13.67	
1949	2,077.70	1,687	1,885	192	14.11	14
1950	1,726.56	1,392	1,556	171	14.55	12
1951	360.18	288	322	38	15.01	3
1952	287.05	228	255	32	15.49	2
1953	1,145.40	902	1,008	137	15.97	9
1954	877.98	685	766	112	16.47	7
1955	3,133.21	2,424	2,709	424	16.98	25
1956	1,794.30	1,375	1,537	258	17.51	15
1957	5,277.55	4,008	4,479	798	18.04	44
1958	1,136.57	855	956	181	18.59	10
1959	1,431.64	1,066	1,191	240	19.15	13
1960	1,139.60	840	939	201	19.72	10
1961	1,739.80	1,269	1,418	322	20.31	16
1962	534.64	386	431	103	20.91	5
1963	1,024.78	731	817	208	21.51	10
1964	2,424.42	1,709	1,910	514	22.13	23
1965	1,904.74	1,327	1,483	422	22.76	19
1966	14,200.26	9,770	10,919	3,281	23.40	140
1967	36,083.66	24,513	27,396	8,688	24.05	361
1968	18,362.30	12,312	13,760	4,602	24.71	186

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1969	11,282.03	7,464	8,342	2,940	25.38	116
1970	6,080.40	3,968	4,435	1,646	26.06	63
1971	15,534.05	9,994	11,169	4,365	26.75	163
1972	18,498.57	11,728	13,107	5,391	27.45	196
1973	38,364.70	23,960	26,778	11,587	28.16	411
1974	49,272.90	30,299	33,862	15,411	28.88	534
1975	37,863.68	22,920	25,615	12,248	29.60	414
1976	13,898.67	8,278	9,251	4,647	30.33	153
1977	19,181.60	11,233	12,554	6,628	31.08	213
1978	24,833.70	14,298	15,979	8,854	31.82	278
1979	27,735.34	15,687	17,532	10,204	32.58	313
1980	38,526.40	21,395	23,911	14,615	33.35	438
1981	41,644.61	22,699	25,368	16,276	34.12	477
1982	29,660.39	17,325	19,362	10,298	31.51	327
1983	47,020.30	27,046	30,227	16,794	31.94	526
1984	51,245.11	29,015	32,427	18,818	32.37	581
1985	70,214.20	38,814	43,378	26,836	33.37	804
1986	74,675.20	40,579	45,351	29,324	33.82	867
1987	61,590.79	32,637	36,475	25,116	34.82	721
1988	64,488.00	33,547	37,492	26,996	35.28	765
1989	63,293.80	32,065	35,836	27,458	36.28	757
1990	76,971.45	38,224	42,719	34,252	36.74	932
1991	69,790.71	33,946	37,938	31,853	37.22	856
1992	74,877.76	35,387	39,548	35,329	38.22	924
1993	94,389.03	43,627	48,757	45,632	38.69	1,179
1994	63,758.76	28,583	31,944	31,814	39.69	802
1995	64,141.55	28,062	31,362	32,780	40.18	816
1996	101,676.17	43,060	48,124	53,552	41.18	1,300
1997	147,067.21	60,651	67,783	79,284	41.67	1,903
1998	219,807.88	87,549	97,845	121,963	42.67	2,858
1999	109,098.49	42,221	47,186	61,912	43.17	1,434
2000	148,695.59	55,434	61,953	86,743	44.17	1,964
2001	49,857.74	18,004	20,121	29,737	44.68	666
2002	51,469.65	17,850	19,949	31,521	45.68	690
2003	48,988.25	16,401	18,330	30,659	46.19	664
2004	503,472.20	161,312	180,282	323,190	47.19	6,849
2005	99,247.65	30,578	34,174	65,074	47.72	1,364
2006	21,099.30	6,195	6,924	14,176	48.72	291
2007	21,366.27	5,963	6,664	14,702	49.72	296
2008	132,857.20	35,885	40,105	92,752	49.99	1,855
2009	5,977.08	1,527	1,707	4,271	50.99	84

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2010	18,300.47	4,440	4,962	13,338	51.52	259
2011	20,776.70	4,733	5,290	15,487	52.53	295
2012	7,943.52	1,705	1,906	6,038	53.07	114
2013	93,193.26	18,620	20,810	72,384	54.07	1,339
2014	11,063.41	2,060	2,302	8,761	54.62	160
2015	2,375.70	407	455	1,921	55.61	35
2016	108,946.54	17,039	19,043	89,904	56.62	1,588
2017	88,797.46	12,654	14,142	74,655	57.17	1,306
2018	1,675.04	214	239	1,436	58.17	25
2019	189.14	21	23	166	58.73	3
	3,374,003.70	1,388,075	1,551,251	1,822,753		42,899

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.5 1.27

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	770.06	770	770			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,545	1,545			
1923	444.90	445	445			
1924	49,481.98	49,482	49,482			
1925	9,550.78	9,551	9,551			
1926	1,437.54	1,438	1,438			
1927	12,577.28	12,504	12,577			
1928	169.18	167	169			
1929	1,786.94	1,752	1,787			
1930	5,907.90	5,750	5,908			
1931	886.67	857	887			
1932	690.68	663	691			
1933	4,845.58	4,616	4,846			
1934	599.15	567	599			
1937	206.12	191	206			
1939	941.28	858	941			
1941	1,497.83	1,346	1,498			
1942	1,321.59	1,179	1,322			
1943	3,799.03	3,363	3,799			
1944	480.46	422	480			
1945	7,388.06	6,441	7,388			
1946	24,241.93	20,974	24,201	41	6.74	6
1947	1,212.46	1,041	1,201	11	7.08	2
1948	11,813.70	10,061	11,609	205	7.42	28
1949	155,416.10	131,296	151,498	3,918	7.76	505
1950	314,103.69	263,219	303,720	10,384	8.10	1,282
1951	117,565.93	97,721	112,757	4,809	8.44	570
1952	14,011.46	11,548	13,325	687	8.79	78
1953	64,035.02	52,329	60,381	3,654	9.14	400

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1954	82,747.60	67,059	77,377	5,370	9.48	566
1955	21,708.32	17,440	20,123	1,585	9.83	161
1956	33,265.27	26,486	30,561	2,704	10.19	265
1957	16,795.88	13,255	15,294	1,501	10.54	142
1958	16,398.95	12,824	14,797	1,602	10.90	147
1959	32,555.72	25,224	29,105	3,451	11.26	306
1960	28,812.28	22,116	25,519	3,293	11.62	283
1961	30,404.90	23,120	26,677	3,728	11.98	311
1962	27,753.65	20,898	24,113	3,640	12.35	295
1963	14,913.85	11,120	12,831	2,083	12.72	164
1964	4,880.13	3,603	4,157	723	13.09	55
1965	18,536.25	13,543	15,627	2,909	13.47	216
1966	5,038.93	3,643	4,204	835	13.85	60
1967	4,718.58	3,376	3,895	823	14.23	58
1968	4,278.86	3,028	3,494	785	14.62	54
1969	8,771.59	6,138	7,082	1,689	15.01	113
1970	5,741.53	3,972	4,583	1,158	15.41	75
1971	25,767.69	17,625	20,337	5,431	15.80	344
1973	11,871.49	7,928	9,148	2,724	16.61	164
1974	25,525.37	16,837	19,428	6,098	17.02	358
1975	87,663.74	57,087	65,871	21,793	17.44	1,250
1976	4,598.73	2,956	3,411	1,188	17.86	67
1977	8,040.17	5,099	5,884	2,157	18.29	118
1978	13,389.00	8,376	9,665	3,724	18.72	199
1979	6,024.51	3,717	4,289	1,736	19.15	91
1980	2,625.97	1,597	1,843	783	19.59	40
1981	3,896.41	2,335	2,694	1,202	20.04	60
1982	4,195.18	2,989	3,449	746	17.86	42
1984	107,312.77	74,808	86,318	20,994	18.36	1,143
1985	3,250.91	2,226	2,569	682	18.99	36
1987	11,800.00	7,873	9,084	2,716	19.58	139
1989	18,115.32	11,742	13,549	4,567	20.22	226
1993	4,421.64	2,676	3,088	1,334	21.69	62
1995	3,605.96	2,107	2,431	1,175	22.22	53
1996	28,053.64	16,038	18,506	9,548	22.66	421
1998	37,254.30	20,415	23,556	13,698	23.30	588
1999	24,770.91	13,230	15,266	9,505	23.77	400
2000	23,959.75	12,454	14,370	9,590	24.25	395
2001	34,304.98	17,410	20,089	14,216	24.50	580
2002	6,262.15	3,083	3,557	2,705	25.01	108
2003	8,507.00	4,075	4,702	3,805	25.29	150

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2004	14,150.50	6,580	7,592	6,558	25.60	256
2005	14,063.28	6,306	7,276	6,787	26.14	260
2006	17,523.06	7,594	8,762	8,761	26.48	331
2007	55,195.64	23,055	26,602	28,593	26.83	1,066
2008	20,558.92	8,330	9,612	10,947	27.16	403
2011	27,987.49	9,891	11,413	16,575	28.36	584
2013	103,921.61	32,964	38,036	65,886	29.06	2,267
2014	188,343.09	56,032	64,653	123,690	29.52	4,190
2019	56,478.77	10,844	12,513	43,966	31.56	1,393
2020	20,252.13	3,423	3,950	16,302	31.96	510
2021	3,292.94	478	552	2,741	32.38	85
2022	36,972.61	4,459	5,145	31,828	32.81	970
2024	446,028.38	30,999	35,769	410,260	33.47	12,258
2025	65,974.61	2,797	3,227	62,747	33.84	1,854
	2,781,411.12	1,526,775	1,742,066	1,039,345		39,603
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,142	4,142			
1927	2,693.18	2,678	2,693			
1930	189.29	184	189			
1933	847.72	808	848			
1936	544.45	508	544			
1938	32.84	30	33			
1952	9,309.40	7,673	9,044	265	8.79	30
1956	5,775.22	4,598	5,420	356	10.19	35
1957	65,555.21	51,736	60,981	4,574	10.54	434
1958	3,928.05	3,072	3,621	307	10.90	28
1959	1,740.26	1,348	1,589	151	11.26	13
1960	10,837.04	8,319	9,806	1,032	11.62	89
1961	15,060.14	11,452	13,498	1,562	11.98	130
1962	44,412.35	33,442	39,418	4,995	12.35	404
1963	61,579.91	45,914	54,118	7,461	12.72	587
1964	33,613.04	24,813	29,247	4,366	13.09	334
1965	24,411.66	17,835	21,022	3,390	13.47	252
1966	17,104.75	12,367	14,577	2,528	13.85	183

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1967	43,814.66	31,345	36,946	6,869	14.23	483
1968	31,758.04	22,472	26,488	5,270	14.62	360
1969	35,461.98	24,816	29,250	6,212	15.01	414
1970	109,477.63	75,737	89,271	20,207	15.41	1,311
1971	28,682.10	19,619	23,125	5,557	15.80	352
1972	14,929.02	10,089	11,892	3,037	16.21	187
1973	43,388.65	28,975	34,153	9,236	16.61	556
1974	6,679.10	4,406	5,193	1,486	17.02	87
1975	2,388.78	1,556	1,834	555	17.44	32
1976	325.75	209	246	79	17.86	4
1977	310.42	197	232	78	18.29	4
1978	5,350.19	3,347	3,945	1,405	18.72	75
1980	6,000.02	3,649	4,301	1,699	19.59	87
1981	66,216.28	39,677	46,767	19,449	20.04	971
1982	55,560.11	39,581	46,654	8,906	17.86	499
1983	28,861.79	20,348	23,984	4,878	18.10	270
1984	5,806.34	4,048	4,771	1,035	18.36	56
1985	10,388.00	7,114	8,385	2,003	18.99	105
1986	10,162.46	6,872	8,100	2,062	19.27	107
1987	21,773.61	14,527	17,123	4,651	19.58	238
1988	9,500.30	6,250	7,367	2,133	19.89	107
1989	21,764.75	14,108	16,629	5,136	20.22	254
1990	17,697.49	11,291	13,309	4,389	20.57	213
1991	2,527.62	1,586	1,869	658	20.93	31
1993	14,187.04	8,586	10,120	4,067	21.69	188
1994	31,906.90	18,934	22,317	9,590	22.10	434
1995	24,723.97	14,449	17,031	7,693	22.22	346
1996	64,217.36	36,713	43,273	20,944	22.66	924
1997	106,890.33	59,720	70,391	36,499	23.10	1,580
1998	90,466.61	49,576	58,435	32,032	23.30	1,375
1999	26,987.42	14,414	16,990	9,998	23.77	421
2000	20,094.65	10,445	12,311	7,783	24.25	321
2001	27,792.71	14,105	16,625	11,167	24.50	456
2002	74,704.50	36,777	43,349	31,356	25.01	1,254
2003	35,723.93	17,112	20,170	15,554	25.29	615
2004	12,600.58	5,859	6,906	5,695	25.60	222
2005	1,094.30	491	579	516	26.14	20
2006	2,275.29	986	1,162	1,113	26.48	42
2007	50,329.62	21,023	24,780	25,550	26.83	952
2008	4,380.00	1,775	2,092	2,288	27.16	84
2009	6,511.91	2,530	2,982	3,530	27.55	128

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2010	2,023.74	751	885	1,139	27.95	41
2014	1,151,949.73	342,705	403,944	748,006	29.52	25,339
2017	18,705.63	4,407	5,194	13,511	30.82	438
2019	630,236.94	121,005	142,628	487,609	31.56	15,450
2020	35,373.19	5,978	7,046	28,327	31.96	886
2023	6,264.54	599	706	5,559	33.13	168
2024	2,560.25	178	210	2,350	33.47	70
	3,323,085.84	1,412,338	1,663,234	1,659,852		61,076
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1908	234.48	234	234			
1910	3,861.59	3,862	3,862			
1915	126.30	126	126			
1923	235.29	235	235			
1925	190.68	191	191			
1927	12,436.94	12,365	12,437			
1928	813.98	804	814			
1930	35.14	34	35			
1936	535.44	499	518	18	3.39	5
1937	4,312.45	3,991	4,140	172	3.73	46
1945	11.76	10	10	1	6.41	
1947	413.05	355	368	45	7.08	6
1948	6,553.87	5,581	5,789	765	7.42	103
1949	1,401.38	1,184	1,228	173	7.76	22
1950	22,787.70	19,096	19,809	2,979	8.10	368
1952	7.75	6	6	2	8.79	
1953	1,739.58	1,422	1,475	265	9.14	29
1954	0.58			1	9.48	
1955	740.69	595	617	123	9.83	13
1956	119.40	95	99	21	10.19	2
1957	1,800.86	1,421	1,474	327	10.54	31
1959	2,182.25	1,691	1,754	428	11.26	38
1960	2,606.73	2,001	2,076	531	11.62	46
1961	2,799.92	2,129	2,208	591	11.98	49
1962	2,082.30	1,568	1,627	456	12.35	37
1963	1,506.73	1,123	1,165	342	12.72	27
1964	244.55	181	188	57	13.09	4

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1965	873.68	638	662	212	13.47	16
1966	2,877.32	2,080	2,158	720	13.85	52
1967	6,144.27	4,396	4,560	1,584	14.23	111
1968	8,237.89	5,829	6,047	2,191	14.62	150
1969	1,214.79	850	882	333	15.01	22
1970	15,096.54	10,444	10,834	4,263	15.41	277
1971	1,337.23	915	949	388	15.80	25
1972	1,686.39	1,140	1,183	504	16.21	31
1973	475.61	318	330	146	16.61	9
1974	889.29	587	609	280	17.02	16
1975	1,607.08	1,047	1,086	521	17.44	30
1977	1,491.56	946	981	510	18.29	28
1980	1,550.75	943	978	573	19.59	29
1984	1,147.18	800	830	317	18.36	17
1985	56,276.04	38,538	39,976	16,300	18.99	858
1986	5,672.61	3,836	3,979	1,693	19.27	88
1988	3,743.66	2,463	2,555	1,189	19.89	60
1989	1,743.75	1,130	1,172	572	20.22	28
1990	2,013.56	1,285	1,333	681	20.57	33
1991	2,592.31	1,626	1,687	906	20.93	43
1994	417.47	248	257	160	22.10	7
1995	815.73	477	495	321	22.22	14
1996	2,818.09	1,611	1,671	1,147	22.66	51
1997	2,053.45	1,147	1,190	864	23.10	37
2003	2,522.29	1,208	1,253	1,269	25.29	50
2004	5,228.61	2,431	2,522	2,707	25.60	106
2006	3,917.66	1,698	1,761	2,156	26.48	81
2007	1,840.52	769	798	1,043	26.83	39
2011	2,842.27	1,004	1,041	1,801	28.36	64
2012	17,220.59	5,769	5,984	11,236	28.79	390
2015	14,049.51	3,895	4,040	10,009	29.99	334
2016	24,794.44	6,377	6,615	18,179	30.32	600
2017	102,116.02	24,059	24,957	77,159	30.82	2,504
2018	150,878.25	32,318	33,524	117,354	31.18	3,764
2019	52,911.67	10,159	10,538	42,373	31.56	1,343
2020	8,613.41	1,456	1,510	7,103	31.96	222
2023	79,428.28	7,593	7,876	71,552	33.13	2,160

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2024	294,630.33	20,477	21,241	273,389	33.47	8,168
2025	106,021.38	4,495	4,663	101,359	33.84	2,995
2026	758,949.48	10,929	11,337	747,613	34.10	21,924
	1,818,522.35	278,730	288,551	1,529,971		47,602
	7,923,019.31	3,217,843	3,693,851	4,229,168		148,281
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.5	1.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1924	95,921.36	84,347	81,946	13,976	9.05	1,544
1925	14,783.67	12,952	12,583	2,200	9.29	237
1926	272,910.74	238,232	231,449	41,462	9.53	4,351
1927	20,830.42	18,114	17,598	3,232	9.78	330
1928	105,626.94	91,501	88,896	16,731	10.03	1,668
1929	124,186.86	107,165	104,114	20,073	10.28	1,953
1930	289,559.86	248,868	241,782	47,777	10.54	4,533
1931	150,765.72	129,055	125,381	25,385	10.80	2,350
1932	15,348.93	13,083	12,711	2,638	11.07	238
1933	5,340.56	4,532	4,403	938	11.35	83
1934	9,645.67	8,150	7,918	1,728	11.63	149
1935	6,843.60	5,756	5,592	1,251	11.92	105
1936	4,264.63	3,570	3,468	796	12.21	65
1937	8,854.73	7,377	7,167	1,688	12.52	135
1938	6,347.72	5,262	5,112	1,236	12.83	96
1939	14,966.84	12,343	11,992	2,975	13.15	226
1940	14,562.94	11,946	11,606	2,957	13.48	219
1941	27,219.31	22,204	21,572	5,647	13.82	409
1942	27,329.22	22,166	21,535	5,794	14.17	409
1943	3,906.94	3,150	3,060	847	14.53	58
1944	5,235.70	4,196	4,077	1,159	14.90	78
1945	9,076.87	7,228	7,022	2,055	15.28	134
1946	336,255.11	266,001	258,428	77,828	15.67	4,967
1947	54,138.58	42,531	41,320	12,818	16.08	797
1948	101,930.43	79,519	77,255	24,675	16.49	1,496
1949	117,850.81	91,264	88,666	29,185	16.92	1,725
1950	1,588,227.12	1,220,600	1,185,848	402,379	17.36	23,179
1951	345,012.00	263,082	255,592	89,420	17.81	5,021
1952	595,406.38	450,365	437,542	157,864	18.27	8,641
1953	688,524.38	516,483	501,778	186,746	18.74	9,965
1954	1,333,383.32	991,504	963,274	370,109	19.23	19,246
1955	1,144,589.91	843,643	819,623	324,967	19.72	16,479
1956	1,719,755.55	1,255,886	1,220,129	499,626	20.23	24,697
1957	1,466,712.94	1,060,917	1,030,711	436,002	20.75	21,012
1958	2,931,804.54	2,099,964	2,040,175	891,630	21.28	41,900
1959	1,727,642.16	1,225,019	1,190,141	537,501	21.82	24,633
1960	2,814,917.23	1,974,946	1,918,716	896,201	22.38	40,045
1961	1,645,064.16	1,141,888	1,109,377	535,687	22.94	23,352
1962	1,755,042.69	1,204,889	1,170,584	584,459	23.51	24,860
1963	2,197,467.51	1,491,355	1,448,894	748,574	24.10	31,061
1964	2,186,758.81	1,466,878	1,425,114	761,645	24.69	30,848

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1965	2,753,692.81	1,825,148	1,773,183	980,509	25.29	38,771
1966	2,929,962.96	1,917,749	1,863,148	1,066,815	25.91	41,174
1967	3,051,803.15	1,972,289	1,916,135	1,135,668	26.53	42,807
1968	3,430,498.72	2,188,212	2,125,910	1,304,588	27.16	48,033
1969	3,835,329.83	2,413,688	2,344,967	1,490,363	27.80	53,610
1970	3,233,131.01	2,006,707	1,949,573	1,283,558	28.45	45,116
1971	3,115,259.75	1,906,134	1,851,864	1,263,396	29.11	43,401
1972	3,000,108.36	1,808,855	1,757,354	1,242,754	29.78	41,731
1973	2,726,784.30	1,619,710	1,573,594	1,153,190	30.45	37,872
1974	3,031,017.67	1,772,539	1,722,072	1,308,945	31.14	42,034
1975	2,187,545.45	1,259,151	1,223,301	964,244	31.83	30,294
1976	1,924,552.91	1,090,067	1,059,031	865,522	32.52	26,615
1977	2,325,525.35	1,295,155	1,258,280	1,067,245	33.23	32,117
1978	2,040,639.81	1,117,189	1,085,381	955,259	33.94	28,146
1979	4,141,431.38	2,227,552	2,164,130	1,977,301	34.66	57,048
1980	8,439,600.23	4,457,206	4,330,303	4,109,297	35.39	116,115
1981	6,142,470.97	3,183,458	3,092,820	3,049,651	36.13	84,408
1982	6,705,461.82	3,856,982	3,747,168	2,958,294	32.68	90,523
1983	1,516,801.34	859,420	834,951	681,850	33.08	20,612
1984	2,207,169.47	1,230,938	1,195,891	1,011,278	33.51	30,178
1985	2,924,165.85	1,592,208	1,546,876	1,377,290	34.51	39,910
1986	4,716,882.62	2,524,947	2,453,058	2,263,825	34.94	64,792
1987	2,038,669.36	1,072,340	1,041,809	996,860	35.37	28,184
1988	4,112,125.10	2,107,875	2,047,861	2,064,264	36.37	56,757
1989	3,536,491.94	1,778,502	1,727,865	1,808,626	36.82	49,121
1990	3,277,040.60	1,615,581	1,569,583	1,707,458	37.28	45,801
1991	3,102,480.44	1,487,329	1,444,983	1,657,498	38.28	43,299
1992	2,402,146.08	1,127,087	1,094,997	1,307,149	38.74	33,742
1993	1,059,552.00	486,122	472,281	587,271	39.22	14,974
1994	864,721.79	384,801	373,845	490,877	40.22	12,205
1995	5,053,635.79	2,195,299	2,132,796	2,920,840	40.69	71,783
1996	4,891,611.89	2,071,598	2,012,617	2,878,995	41.18	69,912
1997	1,901,690.71	778,742	756,570	1,145,121	42.18	27,148
1998	2,310,439.96	920,248	894,047	1,416,393	42.67	33,194
1999	1,112,654.13	430,597	418,337	694,317	43.17	16,083
2000	2,549,504.13	957,084	929,834	1,619,670	43.68	37,080
2001	5,854,232.87	2,113,963	2,053,775	3,800,457	44.68	85,059
2002	1,047,227.62	365,692	355,280	691,947	45.19	15,312
2003	3,315,964.67	1,117,812	1,085,986	2,229,978	45.72	48,775
2004	1,746,907.02	563,552	547,507	1,199,400	46.72	25,672
2005	1,016,683.81	315,375	306,396	710,288	47.25	15,033

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2006	2,670,891.87	795,125	772,487	1,898,405	47.78	39,732
2007	880,682.02	250,906	243,762	636,920	48.32	13,181
2008	2,138,561.33	585,538	568,867	1,569,694	49.07	31,989
2009	2,491,688.81	649,832	631,330	1,860,358	49.61	37,500
2010	2,043,890.66	505,863	491,460	1,552,430	50.17	30,943
2011	1,835,941.50	429,610	417,378	1,418,563	50.73	27,963
2012	2,341,770.71	512,848	498,246	1,843,524	51.72	35,644
2013	3,391,532.42	695,942	676,128	2,715,405	52.29	51,930
2014	4,890,441.94	935,052	908,430	3,982,012	52.86	75,331
2015	9,535,562.16	1,688,748	1,640,667	7,894,895	53.44	147,734
2016	12,527,958.41	2,039,552	1,981,483	10,546,475	54.01	195,269
2017	23,545,106.70	3,489,385	3,390,037	20,155,070	54.60	369,140
2018	19,027,543.95	2,538,274	2,466,006	16,561,538	55.20	300,028
2019	10,568,666.60	1,259,785	1,223,917	9,344,750	55.40	168,678
2020	10,778,047.52	1,120,917	1,089,003	9,689,045	56.00	173,019
2021	24,351,910.98	2,157,579	2,096,150	22,255,761	56.61	393,142
2022	23,029,641.52	1,690,376	1,642,249	21,387,393	56.85	376,207
2023	26,730,458.24	1,545,020	1,501,031	25,229,427	57.10	441,846
2024	15,443,147.88	648,612	630,145	14,813,003	57.02	259,786
2025	21,627,886.23	557,999	542,112	21,085,774	56.64	372,277
2026	17,860,126.36	162,527	157,900	17,702,227	54.45	325,110
	391,269,086.34	109,022,324	105,918,299	285,350,787		6,024,184
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1901	1,995.97	1,897	1,921	75	3.72	20
1903	514.79	486	492	23	4.25	5
1904	335.45	315	319	16	4.51	4
1905	1,550.53	1,452	1,471	80	4.75	17
1906	4,139.13	3,863	3,912	227	5.00	45
1907	10,486.90	9,756	9,881	606	5.23	116
1908	21,093.72	19,558	19,808	1,286	5.46	236
1909	434.23	401	406	28	5.68	5
1910	2,877.47	2,651	2,685	193	5.91	33
1911	5.52	5	5			
1913	2,267.15	2,069	2,095	172	6.56	26
1914	326.05	297	301	25	6.77	4
1916	13.62	12	12	1	7.22	

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1920	4,709.33	4,200	4,254	456	8.11	56
1921	36,225.03	32,197	32,608	3,617	8.34	434
1922	25,265.15	22,375	22,661	2,604	8.58	303
1923	34,615.68	30,549	30,939	3,677	8.81	417
1924	41,316.56	36,331	36,795	4,522	9.05	500
1925	43,015.45	37,687	38,168	4,847	9.29	522
1926	11,272.73	9,840	9,966	1,307	9.53	137
1927	29,391.22	25,559	25,885	3,506	9.78	358
1928	9,567.92	8,288	8,394	1,174	10.03	117
1929	809.19	698	707	102	10.28	10
1930	73,367.25	63,057	63,862	9,505	10.54	902
1931	207,083.58	177,264	179,527	27,556	10.80	2,551
1932	6,251.61	5,329	5,397	855	11.07	77
1933	10,890.67	9,243	9,361	1,530	11.35	135
1934	1,665.34	1,407	1,425	240	11.63	21
1935	2,373.39	1,996	2,021	352	11.92	30
1936	17,186.99	14,389	14,573	2,614	12.21	214
1937	3,763.36	3,135	3,175	588	12.52	47
1938	3,362.30	2,787	2,823	540	12.83	42
1939	1,732.40	1,429	1,447	285	13.15	22
1940	10,189.09	8,358	8,465	1,724	13.48	128
1941	1,384.45	1,129	1,143	241	13.82	17
1942	796.27	646	654	142	14.17	10
1944	455.80	365	370	86	14.90	6
1946	72,664.52	57,483	58,217	14,448	15.67	922
1947	14,893.27	11,700	11,849	3,044	16.08	189
1948	8,457.79	6,598	6,682	1,776	16.49	108
1949	12,804.37	9,916	10,043	2,762	16.92	163
1950	8,663.88	6,658	6,743	1,921	17.36	111
1951	13,131.61	10,013	10,141	2,991	17.81	168
1952	151,969.84	114,950	116,418	35,552	18.27	1,946
1953	337,079.69	252,854	256,082	80,997	18.74	4,322
1954	7,470.38	5,555	5,626	1,844	19.23	96
1955	104,062.83	76,702	77,681	26,382	19.72	1,338
1956	607,273.77	443,474	449,136	158,138	20.23	7,817
1957	1,578,065.32	1,141,462	1,156,036	422,030	20.75	20,339
1958	172,566.81	123,604	125,182	47,385	21.28	2,227
1959	1,084,837.01	769,225	779,046	305,791	21.82	14,014
1960	609,172.64	427,396	432,853	176,320	22.38	7,878
1961	1,222,116.39	848,308	859,139	362,978	22.94	15,823
1962	976,067.49	670,100	678,656	297,412	23.51	12,650

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1963	1,740,261.07	1,181,063	1,196,142	544,119	24.10	22,578
1964	2,893,848.18	1,941,193	1,965,977	927,871	24.69	37,581
1965	2,207,043.52	1,462,828	1,481,505	725,539	25.29	28,689
1966	1,941,888.54	1,271,024	1,287,252	654,637	25.91	25,266
1967	2,172,470.85	1,404,003	1,421,929	750,542	26.53	28,290
1968	3,282,373.58	2,093,728	2,120,460	1,161,914	27.16	42,780
1969	2,924,762.74	1,840,641	1,864,142	1,060,621	27.80	38,152
1970	2,415,126.91	1,498,997	1,518,136	896,991	28.45	31,529
1971	2,192,385.88	1,341,455	1,358,582	833,804	29.11	28,643
1972	3,227,165.43	1,945,755	1,970,598	1,256,568	29.78	42,195
1973	1,171,747.34	696,018	704,904	466,843	30.45	15,331
1974	541,988.38	316,955	321,002	220,987	31.14	7,097
1975	604,011.86	347,669	352,108	251,904	31.83	7,914
1976	407,639.78	230,887	233,835	173,805	32.52	5,345
1977	608,997.12	339,169	343,499	265,498	33.23	7,990
1978	578,010.83	316,444	320,484	257,527	33.94	7,588
1979	1,011,349.10	543,974	550,919	460,430	34.66	13,284
1980	958,905.86	506,427	512,893	446,013	35.39	12,603
1981	2,977,672.74	1,543,238	1,562,941	1,414,731	36.13	39,157
1982	4,646,330.61	2,672,569	2,706,691	1,939,639	32.68	59,352
1983	446,066.02	252,741	255,968	190,098	33.08	5,747
1984	1,522,276.37	848,974	859,813	662,463	33.51	19,769
1985	1,494,741.30	813,887	824,278	670,463	34.51	19,428
1986	1,331,328.83	712,660	721,759	609,570	34.94	17,446
1987	1,647,342.86	866,502	877,565	769,778	35.37	21,764
1988	1,750,418.72	897,265	908,721	841,698	36.37	23,143
1989	1,562,513.00	785,788	795,821	766,692	36.82	20,823
1990	1,292,468.60	637,187	645,322	647,146	37.28	17,359
1991	830,195.18	397,996	403,077	427,118	38.28	11,158
1992	2,811,113.99	1,318,975	1,335,815	1,475,299	38.74	38,082
1993	857,032.68	393,207	398,227	458,805	39.22	11,698
1994	1,527,499.67	679,737	688,416	839,084	40.22	20,862
1995	1,207,863.65	524,696	531,395	676,469	40.69	16,625
1996	8,834,114.84	3,741,248	3,789,015	5,045,100	41.18	122,513
1997	7,711,305.67	3,157,780	3,198,097	4,513,208	42.18	106,999
1998	3,531,697.80	1,406,675	1,424,635	2,107,063	42.67	49,380
1999	441,939.65	171,031	173,215	268,725	43.17	6,225
2000	8,095,337.86	3,038,990	3,077,791	5,017,547	43.68	114,871
2001	2,134,278.91	770,688	780,528	1,353,751	44.68	30,299
2002	5,026,934.36	1,755,405	1,777,817	3,249,117	45.19	71,899
2003	2,485,073.64	837,718	848,414	1,636,660	45.72	35,797

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2004	2,646,643.20	853,807	864,708	1,781,935	46.72	38,141
2005	2,720,395.30	843,867	854,641	1,865,754	47.25	39,487
2006	1,309,590.96	389,865	394,843	914,748	47.78	19,145
2007	913,060.03	260,131	263,452	649,608	48.32	13,444
2008	2,779,024.03	760,897	770,612	2,008,412	49.07	40,930
2009	549,886.95	143,411	145,242	404,645	49.61	8,157
2010	2,401,288.41	594,319	601,907	1,799,381	50.17	35,866
2011	1,322,202.40	309,395	313,345	1,008,857	50.73	19,887
2012	2,641,760.43	578,546	585,933	2,055,828	51.72	39,749
2013	4,755,306.51	975,789	988,247	3,767,059	52.29	72,042
2014	15,633,330.00	2,989,093	3,027,257	12,606,073	52.86	238,480
2015	16,450,218.74	2,913,334	2,950,530	13,499,688	53.44	252,614
2016	11,959,623.18	1,947,027	1,971,886	9,987,737	54.01	184,924
2017	7,079,788.76	1,049,225	1,062,621	6,017,168	54.60	110,205
2018	60,874,845.51	8,120,704	8,224,386	52,650,460	55.20	953,813
2019	7,278,273.24	867,570	878,647	6,399,626	55.40	115,517
2020	9,044,286.69	940,606	952,615	8,091,671	56.00	144,494
2021	3,416,064.40	302,663	306,527	3,109,537	56.61	54,929
2022	7,426,125.08	545,078	552,037	6,874,088	56.85	120,916
2023	9,779,496.43	565,255	572,472	9,207,024	57.10	161,244
2024	3,832,893.29	160,982	163,037	3,669,856	57.02	64,361
2025	4,774,564.95	123,184	124,757	4,649,808	56.64	82,094
2026	5,992,073.00	54,528	55,224	5,936,849	54.45	109,033
	288,230,294.31	79,309,481	80,322,072	207,908,222		4,300,401
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1918	3.10	3	3			
1919	92.95	83	91	2	7.89	
1921	39.40	35	38	1	8.34	
1923	7,302.21	6,444	7,061	241	8.81	27
1924	482.00	424	465	17	9.05	2
1925	5,019.20	4,397	4,818	201	9.29	22
1926	3,715.80	3,244	3,555	161	9.53	17
1927	6,704.58	5,830	6,388	316	9.78	32
1928	21,685.99	18,786	20,585	1,101	10.03	110
1929	69.79	60	66	4	10.28	
1930	165.98	143	157	9	10.54	1

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1931	4.97	4	4	1	10.80	
1932	48,049.84	40,958	44,880	3,170	11.07	286
1933	153.60	130	142	11	11.35	1
1934	8.58	7	8	1	11.63	
1935	76.92	65	71	6	11.92	1
1936	526.27	441	483	43	12.21	4
1937	1.04	1	1			
1938	68.07	56	61	7	12.83	1
1939	4,695.13	3,872	4,243	452	13.15	34
1940	2,794.55	2,292	2,511	283	13.48	21
1941	35,701.99	29,123	31,912	3,790	13.82	274
1942	264.15	214	234	30	14.17	2
1943	1,651.60	1,332	1,460	192	14.53	13
1944	5,529.01	4,431	4,855	674	14.90	45
1945	300.47	239	262	39	15.28	3
1946	8,070.49	6,384	6,995	1,075	15.67	69
1947	8,690.42	6,827	7,481	1,210	16.08	75
1948	3,499.56	2,730	2,991	508	16.49	31
1949	81,254.04	62,923	68,949	12,305	16.92	727
1951	19,296.97	14,715	16,124	3,173	17.81	178
1952	2,674.81	2,023	2,217	458	18.27	25
1953	30,131.65	22,603	24,767	5,364	18.74	286
1954	23,196.56	17,249	18,901	4,296	19.23	223
1955	10,643.92	7,845	8,596	2,048	19.72	104
1956	39,007.60	28,486	31,214	7,794	20.23	385
1957	51,538.88	37,280	40,850	10,689	20.75	515
1958	16,561.60	11,863	12,999	3,563	21.28	167
1959	57,053.76	40,455	44,329	12,725	21.82	583
1960	49,789.16	34,932	38,277	11,512	22.38	514
1961	137,112.11	95,174	104,288	32,824	22.94	1,431
1962	211,149.77	144,961	158,843	52,307	23.51	2,225
1963	431,996.80	293,183	321,258	110,738	24.10	4,595
1964	469,250.34	314,773	344,916	124,334	24.69	5,036
1965	328,470.25	217,710	238,558	89,912	25.29	3,555
1966	689,046.61	451,002	494,190	194,856	25.91	7,520
1967	298,810.04	193,112	211,605	87,205	26.53	3,287
1968	528,215.21	336,933	369,198	159,017	27.16	5,855
1969	440,154.30	277,002	303,528	136,626	27.80	4,915
1970	337,286.83	209,344	229,391	107,896	28.45	3,792
1971	266,079.64	162,806	178,396	87,683	29.11	3,012
1972	156,110.68	94,124	103,137	52,973	29.78	1,779

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1973	318,392.80	189,125	207,236	111,157	30.45	3,650
1974	307,635.88	179,905	197,133	110,503	31.14	3,549
1975	109,349.07	62,941	68,968	40,381	31.83	1,269
1976	258,115.71	146,197	160,197	97,919	32.52	3,011
1977	118,593.89	66,048	72,373	46,221	33.23	1,391
1978	350,695.85	191,995	210,381	140,315	33.94	4,134
1979	156,231.43	84,032	92,079	64,152	34.66	1,851
1980	215,891.18	114,019	124,938	90,954	35.39	2,570
1981	221,361.45	114,725	125,711	95,650	36.13	2,647
1982	230,933.02	132,833	145,553	85,380	32.68	2,613
1983	348,679.77	197,562	216,481	132,199	33.08	3,996
1984	135,769.74	75,719	82,970	52,800	33.51	1,576
1985	395,965.88	215,603	236,249	159,717	34.51	4,628
1986	634,310.33	339,546	372,061	262,249	34.94	7,506
1987	120,321.79	63,289	69,350	50,972	35.37	1,441
1988	167,170.50	85,692	93,898	73,273	36.37	2,015
1989	378,505.17	190,350	208,578	169,927	36.82	4,615
1990	82,109.78	40,480	44,356	37,753	37.28	1,013
1991	530,439.18	254,293	278,644	251,795	38.28	6,578
1992	1,289,702.95	605,129	663,077	626,626	38.74	16,175
1993	616,758.94	282,969	310,066	306,693	39.22	7,820
1995	948.49	412	451	497	40.69	12
1996	637,887.11	270,145	296,014	341,873	41.18	8,302
1997	672,935.90	275,567	301,956	370,980	42.18	8,795
1998	948,075.37	377,618	413,779	534,296	42.67	12,522
1999	347,386.18	134,438	147,312	200,074	43.17	4,635
2000	3,596,452.81	1,350,108	1,479,395	2,117,057	43.68	48,467
2001	404,836.66	146,187	160,186	244,651	44.68	5,476
2002	1,539,167.01	537,477	588,946	950,221	45.19	21,027
2003	339,813.94	114,551	125,520	214,293	45.72	4,687
2004	4,190,475.18	1,351,847	1,481,301	2,709,174	46.72	57,987
2005	6,335,599.60	1,965,303	2,153,502	4,182,098	47.25	88,510
2006	2,578,688.22	767,675	841,188	1,737,500	47.78	36,365
2007	1,038,295.06	295,810	324,137	714,158	48.32	14,780
2008	147,802.39	40,468	44,343	103,459	49.07	2,108
2009	3,180,399.22	829,448	908,877	2,271,523	49.61	45,788
2010	950,547.13	235,260	257,789	692,758	50.17	13,808
2011	2,253,711.02	527,368	577,869	1,675,842	50.73	33,035
2012	503,081.69	110,175	120,725	382,356	51.72	7,393
2013	943,389.92	193,584	212,122	731,268	52.29	13,985
2014	487,903.78	93,287	102,220	385,684	52.86	7,296

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2015	2,324,377.33	411,647	451,067	1,873,311	53.44	35,054
2016	9,552,876.46	1,555,208	1,704,136	7,848,741	54.01	145,320
2017	7,595,417.74	1,125,641	1,233,433	6,361,984	54.60	116,520
2018	5,192,514.74	692,681	759,013	4,433,502	55.20	80,317
2019	4,116,258.30	490,658	537,644	3,578,615	55.40	64,596
2020	12,073,065.64	1,255,599	1,375,836	10,697,230	56.00	191,022
2021	3,979,288.42	352,565	386,327	3,592,962	56.61	63,469
2022	7,571,625.48	555,757	608,977	6,962,649	56.85	122,474
2023	1,593,492.89	92,104	100,924	1,492,569	57.10	26,140
2024	5,555,300.43	233,323	255,666	5,299,634	57.02	92,943
2025	436,695.79	11,267	12,346	424,350	56.64	7,492
2026	4,710,926.29	42,869	46,974	4,663,952	54.45	85,656
	107,626,369.69	23,277,552	25,506,628	82,119,742		1,601,809
	787,125,750.34	211,609,357	211,746,999	575,378,751		11,926,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.2 1.52

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1901	665.32	657	665			
1902	1,876.45	1,852	1,876			
1903	661.31	652	661			
1904	1,470.23	1,450	1,470			
1905	930.38	917	930			
1906	1,039.29	1,025	1,039			
1907	1,672.43	1,649	1,672			
1908	4,594.00	4,529	4,594			
1909	1,516.23	1,495	1,516			
1910	781.01	770	781			
1911	3,276.38	3,229	3,276			
1912	2,805.58	2,765	2,806			
1913	870.86	858	871			
1914	3,083.63	3,039	3,084			
1915	3,725.15	3,671	3,725			
1916	2,084.30	2,054	2,084			
1917	2,302.84	2,269	2,303			
1918	1,613.19	1,589	1,613			
1919	5,743.39	5,659	5,743			
1920	5,437.10	5,356	5,437			
1921	2,270.62	2,237	2,271			
1922	33,123.16	32,629	33,123			
1923	7,935.08	7,816	7,935			
1924	36,316.13	35,772	36,316			
1925	7,038.34	6,933	7,038			
1926	16,015.63	15,772	16,016			
1927	19,332.45	19,038	19,332			
1928	14,711.22	14,487	14,711			
1929	22,640.69	22,295	22,641			
1930	11,103.53	10,933	11,104			
1931	3,414.62	3,362	3,415			
1932	1,643.47	1,618	1,643			
1933	93.97	93	94			
1934	201.46	198	201			
1935	1,404.76	1,383	1,405			
1936	2,219.81	2,185	2,220			
1937	1,507.39	1,484	1,507			
1938	1,013.48	997	1,013			
1939	4,543.85	4,471	4,544			
1940	3,443.16	3,388	3,443			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1941	6,305.26	6,204	6,305			
1942	455.82	448	456			
1943	1,059.36	1,042	1,059			
1944	2,021.15	1,988	2,021			
1945	233.29	229	233			
1946	3,466.43	3,409	3,466			
1947	4,534.23	4,459	4,534			
1948	13,944.47	13,712	13,944			
1949	14,981.32	14,730	14,981			
1950	9,771.29	9,606	9,771			
1951	14,464.65	14,216	14,465			
1952	19,332.52	18,998	19,333			
1953	13,918.64	13,676	13,919			
1954	23,732.78	23,316	23,733			
1955	45,943.45	45,130	45,943			
1956	22,722.46	22,317	22,722			
1957	31,202.14	30,641	31,202			
1958	12,729.72	12,499	12,730			
1959	34,438.45	33,808	34,438			
1960	5,230.46	5,134	5,230			
1962	3,625.02	3,557	3,625			
1968	316.24	310	316			
2025	30,687.51	18,440	31,974	1,286-		
	551,238.55	530,445	552,525	1,286-		
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1903	827.90	817	821	7	0.87	7
1904	1,600.92	1,579	1,587	13	0.89	13
1905	59.45	59	59			
1906	3,388.02	3,341	3,359	29	0.91	29
1908	45.16	45	45			
1910	2,040.42	2,011	2,022	19	0.93	19
1911	13,104.26	12,916	12,985	119	0.93	119
1912	4,993.79	4,921	4,947	46	0.94	46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1923	297.99	294	296	2	0.96	2
1943	508.36	500	503	6	0.98	6
1952	86,661.17	85,161	85,616	1,045	0.99	1,045
	113,527.44	111,644	112,241	1,286		1,286
	664,765.99	642,089	664,766			1,286

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.19

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1972	21,937.59	15,014	14,603	7,335	21.46	342
1973	50,905.78	34,347	33,406	17,500	22.12	791
1974	12,259.91	8,153	7,930	4,330	22.78	190
1975	43,566.07	28,536	27,754	15,812	23.46	674
1976	449,740.76	290,015	282,072	167,669	24.15	6,943
1977	460,683.14	292,331	284,324	176,359	24.85	7,097
1978	665,396.36	415,380	404,003	261,394	25.55	10,231
1979	516,795.11	317,147	308,460	208,335	26.27	7,931
1980	1,110,301.00	669,445	651,109	459,192	27.00	17,007
1981	1,439,574.58	852,530	829,179	610,395	27.73	22,012
1982	1,968,821.01	1,245,870	1,211,746	757,075	25.68	29,481
1983	2,385,906.70	1,485,943	1,445,243	940,664	26.19	35,917
1984	3,271,806.54	2,004,309	1,949,411	1,322,395	26.72	49,491
1985	3,462,084.53	2,070,673	2,013,957	1,448,127	27.72	52,241
1986	4,311,699.41	2,533,555	2,464,161	1,847,538	28.25	65,400
1987	7,549,948.82	4,356,320	4,237,001	3,312,948	28.78	115,113
1988	10,794,533.71	6,069,766	5,903,515	4,891,018	29.78	164,238
1989	13,115,435.25	7,230,539	7,032,495	6,082,940	30.32	200,625
1990	14,925,585.93	8,061,309	7,840,510	7,085,076	30.87	229,513
1991	8,983,178.68	4,717,965	4,588,740	4,394,439	31.87	137,886
1992	6,992,415.04	3,592,703	3,494,299	3,498,116	32.41	107,933
1993	5,199,029.06	2,610,432	2,538,932	2,660,097	32.97	80,682
1994	9,435,212.03	4,625,141	4,498,459	4,936,753	33.54	147,190
1995	15,158,862.92	7,200,460	7,003,240	8,155,623	34.54	236,121
1996	9,107,473.65	4,214,939	4,099,492	5,007,982	35.11	142,637
1997	14,046,220.23	6,285,684	6,113,519	7,932,701	36.11	219,682
1998	9,910,714.55	4,311,161	4,193,078	5,717,636	36.69	155,836
1999	10,443,272.93	4,411,238	4,290,414	6,152,859	37.26	165,133
2000	10,899,943.37	4,435,187	4,313,707	6,586,236	38.26	172,144
2001	10,993,250.62	4,330,241	4,211,636	6,781,615	38.85	174,559
2002	10,159,401.22	3,867,684	3,761,748	6,397,653	39.45	162,171
2003	14,250,702.27	5,201,506	5,059,037	9,191,665	40.45	227,235
2004	13,292,075.76	4,673,494	4,545,487	8,746,589	41.04	213,124
2005	14,279,332.05	4,795,000	4,663,665	9,615,667	42.04	228,727
2006	14,964,026.20	4,818,416	4,686,440	10,277,586	42.64	241,032
2007	14,117,351.65	4,321,321	4,202,960	9,914,391	43.64	227,186
2008	11,807,468.35	3,495,011	3,399,283	8,408,186	44.00	191,095
2009	11,335,790.01	3,174,021	3,087,085	8,248,705	45.00	183,305
2010	11,835,939.48	3,143,626	3,057,522	8,778,417	45.61	192,467
2011	16,673,207.98	4,186,643	4,071,971	12,601,237	46.23	272,577
2012	22,308,120.52	5,240,178	5,096,650	17,211,471	47.23	364,418

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2013	29,816,506.00	6,559,631	6,379,963	23,436,543	47.85	489,792
2014	33,083,388.78	6,742,395	6,557,721	26,525,668	48.85	543,002
2015	31,408,549.50	5,923,652	5,761,403	25,647,146	49.48	518,334
2016	43,881,422.28	7,556,381	7,349,412	36,532,010	50.48	723,693
2017	39,438,063.21	6,183,888	6,014,512	33,423,552	51.10	654,081
2018	51,345,245.24	7,198,603	7,001,434	44,343,812	52.11	850,965
2019	71,470,485.36	8,898,075	8,654,357	62,816,128	52.74	1,191,053
2020	79,175,870.21	8,598,500	8,362,987	70,812,883	53.38	1,326,581
2021	88,002,799.97	8,078,657	7,857,383	80,145,417	54.38	1,473,803
2022	108,389,823.08	8,194,271	7,969,830	100,419,993	55.02	1,825,154
2023	129,099,789.76	7,642,708	7,433,375	121,666,415	55.67	2,185,493
2024	101,355,079.48	4,307,591	4,189,606	97,165,473	56.32	1,725,239
2025	117,422,827.65	3,006,024	2,923,689	114,499,139	56.98	2,009,462
2026	118,083,613.91	1,027,327	999,189	117,084,425	56.97	2,055,194
	1,374,723,435.20	225,550,936	219,373,106	1,155,350,329		22,830,223
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1973	285,943.39	192,929	194,518	91,426	22.12	4,133
1974	571,276.23	379,899	383,027	188,249	22.78	8,264
1975	1,585,505.88	1,038,506	1,047,058	538,448	23.46	22,952
1976	1,082,269.19	697,901	703,648	378,621	24.15	15,678
1977	1,335,772.82	847,628	854,608	481,165	24.85	19,363
1978	1,708,289.08	1,066,417	1,075,199	633,090	25.55	24,778
1979	1,928,748.04	1,183,634	1,193,381	735,367	26.27	27,993
1980	2,072,814.28	1,249,783	1,260,075	812,739	27.00	30,101
1981	1,509,220.60	893,776	901,136	608,084	27.73	21,929
1982	1,530,362.71	968,414	976,389	553,974	25.68	21,572
1983	804,970.68	501,336	505,465	299,506	26.19	11,436
1984	1,006,550.78	616,613	621,691	384,860	26.72	14,403
1985	1,290,476.33	771,834	778,190	512,286	27.72	18,481
1986	1,964,668.58	1,154,439	1,163,946	800,723	28.25	28,344
1987	3,184,748.58	1,837,600	1,852,733	1,332,016	28.78	46,283
1988	5,801,626.88	3,262,255	3,289,120	2,512,507	29.78	84,369
1989	4,269,690.78	2,353,881	2,373,265	1,896,426	30.32	62,547
1990	4,733,284.34	2,556,447	2,577,499	2,155,785	30.87	69,834
1991	2,194,901.43	1,152,762	1,162,255	1,032,646	31.87	32,402
1992	2,721,268.76	1,398,188	1,409,702	1,311,567	32.41	40,468

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1993	2,622,674.17	1,316,845	1,327,689	1,294,985	32.97	39,278
1994	5,296,653.23	2,596,419	2,617,801	2,678,853	33.54	79,870
1995	5,559,019.49	2,640,534	2,662,279	2,896,741	34.54	83,866
1996	6,482,599.31	3,000,147	3,024,853	3,457,746	35.11	98,483
1997	9,935,459.13	4,446,118	4,482,732	5,452,727	36.11	151,003
1998	7,416,660.98	3,226,248	3,252,816	4,163,845	36.69	113,487
1999	5,207,337.78	2,199,579	2,217,693	2,989,645	37.26	80,237
2000	4,059,336.98	1,651,744	1,665,346	2,393,991	38.26	62,572
2001	7,084,986.27	2,790,776	2,813,758	4,271,228	38.85	109,942
2002	3,168,760.14	1,206,347	1,216,281	1,952,479	39.45	49,492
2003	3,581,071.06	1,307,091	1,317,855	2,263,216	40.45	55,951
2004	8,089,593.18	2,844,301	2,867,724	5,221,869	41.04	127,239
2005	6,591,715.67	2,213,498	2,231,726	4,359,989	42.04	103,710
2006	3,974,804.13	1,279,887	1,290,427	2,684,377	42.64	62,954
2007	5,604,562.97	1,715,557	1,729,685	3,874,878	43.64	88,792
2008	4,653,532.53	1,377,446	1,388,789	3,264,743	44.00	74,199
2009	5,583,404.38	1,563,353	1,576,227	4,007,177	45.00	89,048
2010	4,087,238.03	1,085,570	1,094,510	2,992,728	45.61	65,616
2011	5,582,246.86	1,401,702	1,413,245	4,169,002	46.23	90,180
2012	8,819,198.91	2,071,630	2,088,690	6,730,509	47.23	142,505
2013	5,525,828.23	1,215,682	1,225,693	4,300,135	47.85	89,867
2014	8,072,835.06	1,645,244	1,658,793	6,414,042	48.85	131,301
2015	15,560,456.49	2,934,702	2,958,869	12,601,587	49.48	254,680
2016	18,093,866.97	3,115,764	3,141,422	14,952,445	50.48	296,205
2017	21,008,323.20	3,294,105	3,321,232	17,687,091	51.10	346,127
2018	22,643,126.41	3,174,566	3,200,709	19,442,418	52.11	373,103
2019	28,508,972.71	3,549,367	3,578,596	24,930,377	52.74	472,703
2020	26,689,179.90	2,898,445	2,922,314	23,766,866	53.38	445,239
2021	24,396,025.61	2,239,555	2,257,998	22,138,028	54.38	407,099
2022	32,679,413.95	2,470,564	2,490,909	30,188,505	55.02	548,682
2023	32,078,527.81	1,899,049	1,914,688	30,163,840	55.67	541,833
2024	22,696,804.91	964,614	972,558	21,724,247	56.32	385,729
2025	22,679,795.02	580,603	585,384	22,094,411	56.98	387,757
2026	33,876,383.90	294,725	297,152	33,579,232	56.97	589,420
	469,492,784.73	96,336,019	97,129,348	372,363,437		7,643,499

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1967	6,335.74	4,625	5,043	1,293	18.36	70
1968	12,972.27	9,355	10,200	2,772	18.96	146
1969	7,113.75	5,067	5,525	1,589	19.56	81
1970	26,077.65	18,335	19,991	6,087	20.19	301
1971	367,004.04	254,635	277,630	89,374	20.82	4,293
1972	554,835.74	379,735	414,027	140,808	21.46	6,561
1973	432,495.32	291,809	318,161	114,334	22.12	5,169
1974	650,274.45	432,433	471,484	178,790	22.78	7,849
1975	579,490.14	379,566	413,843	165,647	23.46	7,061
1976	357,453.58	230,504	251,320	106,134	24.15	4,395
1977	654,024.95	415,018	452,497	201,528	24.85	8,110
1978	540,592.84	337,470	367,946	172,647	25.55	6,757
1979	499,091.85	306,283	333,942	165,150	26.27	6,287
1980	722,230.76	435,462	474,787	247,444	27.00	9,165
1981	846,012.42	501,017	546,262	299,750	27.73	10,810
1982	763,161.10	482,928	526,539	236,622	25.68	9,214
1983	885,146.87	551,269	601,052	284,095	26.19	10,847
1984	1,413,930.75	866,174	944,395	469,536	26.72	17,572
1985	1,607,338.45	961,349	1,048,165	559,173	27.72	20,172
1986	1,900,089.22	1,116,492	1,217,318	682,771	28.25	24,169
1987	1,452,021.25	837,816	913,476	538,545	28.78	18,712
1988	2,125,316.52	1,195,065	1,302,987	822,330	29.78	27,613
1989	2,188,863.49	1,206,720	1,315,695	873,169	30.32	28,798
1990	2,309,948.62	1,247,603	1,360,270	949,679	30.87	30,764
1991	2,661,154.41	1,397,638	1,523,854	1,137,301	31.87	35,686
1992	2,182,788.86	1,121,517	1,222,797	959,992	32.41	29,620
1993	3,411,757.06	1,713,043	1,867,742	1,544,015	32.97	46,831
1994	3,473,892.60	1,702,902	1,856,685	1,617,208	33.54	48,217
1995	3,840,636.59	1,824,302	1,989,048	1,851,588	34.54	53,607
1996	4,753,329.33	2,199,841	2,398,501	2,354,829	35.11	67,070
1997	4,892,363.06	2,189,332	2,387,043	2,505,320	36.11	69,380
1998	5,703,979.85	2,481,231	2,705,302	2,998,678	36.69	81,730
1999	3,394,996.41	1,434,046	1,563,550	1,831,447	37.26	49,153
2000	4,946,978.26	2,012,925	2,194,705	2,752,273	38.26	71,936
2001	2,507,729.29	987,795	1,076,999	1,430,730	38.85	36,827
2002	4,147,455.69	1,578,936	1,721,524	2,425,932	39.45	61,494
2003	4,408,587.09	1,609,134	1,754,449	2,654,138	40.45	65,615
2004	4,625,903.84	1,626,468	1,773,348	2,852,555	41.04	69,507
2005	4,736,422.04	1,590,491	1,734,122	3,002,300	42.04	71,415
2006	6,355,208.15	2,046,377	2,231,178	4,124,030	42.64	96,717
2007	5,421,452.01	1,659,506	1,809,370	3,612,082	43.64	82,770

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2008	4,893,893.88	1,448,593	1,579,410	3,314,484	44.00	75,329
2009	4,332,902.51	1,213,213	1,322,774	3,010,129	45.00	66,892
2010	6,200,915.11	1,646,963	1,795,694	4,405,221	45.61	96,585
2011	7,177,644.08	1,802,306	1,965,066	5,212,578	46.23	112,753
2012	5,190,143.89	1,219,165	1,329,263	3,860,881	47.23	81,746
2013	5,526,544.52	1,215,840	1,325,638	4,200,906	47.85	87,793
2014	7,533,801.45	1,535,389	1,674,044	5,859,757	48.85	119,954
2015	14,011,953.53	2,642,654	2,881,303	11,130,651	49.48	224,953
2016	12,504,575.86	2,153,288	2,347,744	10,156,832	50.48	201,205
2017	12,707,927.80	1,992,603	2,172,548	10,535,380	51.10	206,172
2018	16,654,022.25	2,334,894	2,545,750	14,108,272	52.11	270,740
2019	7,833,442.74	975,264	1,063,337	6,770,106	52.74	128,368
2020	4,758,726.19	516,798	563,468	4,195,258	53.38	78,592
2021	11,468,813.83	1,052,837	1,147,915	10,320,899	54.38	189,792
2022	15,251,137.98	1,152,986	1,257,108	13,994,030	55.02	254,344
2023	18,770,878.67	1,111,236	1,211,588	17,559,291	55.67	315,417
2024	21,557,601.18	916,198	998,937	20,558,665	56.32	365,033
2025	23,698,943.89	606,693	661,481	23,037,463	56.98	404,308
2026	30,015,234.63	261,133	284,715	29,730,520	56.97	521,863
	322,455,560.30	67,440,267	73,530,554	248,925,006		5,104,330
	2,166,671,780.23	389,327,222	390,033,008	1,776,638,772		35,578,052
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					49.9	1.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1901	1,823.44	1,692	1,663	160	5.04	32
1902	858.12	793	780	78	5.33	15
1903	2,783.58	2,560	2,517	267	5.62	48
1904	6,859.36	6,282	6,176	683	5.89	116
1905	2,828.98	2,580	2,536	293	6.15	48
1906	4,634.90	4,210	4,139	496	6.41	77
1907	3,011.94	2,726	2,680	332	6.64	50
1908	6,470.50	5,834	5,736	735	6.88	107
1909	6,566.28	5,900	5,800	766	7.10	108
1910	8,992.96	8,053	7,917	1,076	7.31	147
1911	19,368.44	17,287	16,995	2,373	7.52	316
1912	12,488.38	11,110	10,923	1,566	7.72	203
1913	19,952.20	17,692	17,393	2,559	7.92	323
1914	52,379.23	46,304	45,523	6,856	8.11	845
1915	24,228.79	21,352	20,992	3,237	8.30	390
1916	19,636.02	17,253	16,962	2,674	8.48	315
1917	3,879.82	3,399	3,342	538	8.65	62
1918	4,097.87	3,580	3,520	578	8.82	66
1919	5,274.03	4,595	4,517	757	8.98	84
1920	2,322.08	2,018	1,984	338	9.14	37
1921	9,356.23	8,108	7,971	1,385	9.30	149
1922	14,230.62	12,300	12,092	2,138	9.45	226
1923	14,826.56	12,783	12,567	2,259	9.59	236
1924	43,133.11	37,091	36,465	6,668	9.74	685
2025	4,827.55	483	475	4,353	13.49	323
	294,830.99	255,985	251,666	43,165		5,008
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,183.84	1,084	1,103	80	5.89	14
1906	505.47	459	467	38	6.41	6
1911	733.05	654	666	67	7.52	9
1912	2,886.54	2,568	2,614	273	7.72	35
1914	339.20	300	305	34	8.11	4
1915	4,350.95	3,834	3,903	448	8.30	54
1916	121.20	106	108	13	8.48	2

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1924	17.25	15	15	2	9.74	
1928	52.02	44	45	7	10.26	1
1939	125.74	105	107	19	11.42	2
1940	30.00	25	25	5	11.51	
1943	25.03	21	21	4	11.76	
	10,370.29	9,215	9,380	990		127
	305,201.28	265,200	261,046	44,155		5,135

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.6 1.68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	181,787	300,224	1,021,864	34.50	29,619
	1,322,088.00	181,787	300,224	1,021,864		29,619

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.5 2.24

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	56.94	57	57			
1916	178.88	179	179			
1919	854.56	855	855			
1920	203.54	204	204			
1921	60.56	61	61			
1923	339.99	340	340			
1924	952.75	953	953			
1926	1,115.15	1,115	1,115			
1927	2,445.73	2,446	2,446			
1928	45.99	46	46			
1929	640.92	641	641			
1930	751.57	752	752			
1931	2,333.02	2,318	2,333			
1935	52.09	50	52			
1936	385.79	369	386			
1937	1,310.12	1,242	1,310			
1940	176.18	163	176			
1941	66.98	61	66	1	3.97	
1942	2,229.00	2,027	2,204	25	4.35	6
1943	941.77	849	923	19	4.73	4
1945	656.02	581	632	24	5.48	4
1946	828.38	727	790	38	5.86	6
1947	2,558.65	2,225	2,419	139	6.25	22
1948	1,715.73	1,479	1,608	108	6.63	16
1949	1,272.83	1,087	1,182	91	7.02	13
1950	12,239.06	10,352	11,256	984	7.40	133
1951	9,018.09	7,555	8,214	804	7.79	103
1952	18,075.38	14,995	16,304	1,772	8.18	217
1953	15,873.74	13,040	14,178	1,696	8.57	198
1954	57,968.55	47,148	51,263	6,705	8.96	748
1955	21,734.50	17,496	19,023	2,711	9.36	290
1956	92,867.64	74,004	80,463	12,405	9.75	1,272
1957	22,535.12	17,770	19,321	3,214	10.15	317
1958	34,165.01	26,656	28,983	5,182	10.55	491
1959	4,213.97	3,253	3,537	677	10.95	62
1960	30,646.32	23,400	25,442	5,204	11.35	459
1961	35,208.26	26,582	28,902	6,306	11.76	536
1962	39,212.23	29,279	31,834	7,378	12.16	607
1963	23,507.57	17,351	18,865	4,642	12.57	369
1964	17,386.82	12,685	13,792	3,595	12.98	277
1965	12,507.81	9,016	9,803	2,705	13.40	202

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1966	23,069.56	16,432	17,866	5,203	13.81	377
1967	49,708.05	34,972	38,024	11,684	14.23	821
1968	36,872.72	25,619	27,855	9,018	14.65	616
1969	26,040.02	17,864	19,423	6,617	15.07	439
1970	35,647.90	24,144	26,251	9,397	15.49	607
1971	177,977.95	118,948	129,330	48,648	15.92	3,056
1972	52,145.55	34,384	37,385	14,761	16.35	903
1973	11,620.50	7,558	8,218	3,403	16.78	203
1974	60,936.35	39,088	42,500	18,437	17.21	1,071
1975	44,570.07	28,181	30,641	13,929	17.65	789
1976	69,647.83	43,399	47,187	22,461	18.09	1,242
1977	28,911.64	17,751	19,300	9,611	18.53	519
1978	35,100.24	21,228	23,081	12,019	18.97	634
1979	32,840.23	19,554	21,261	11,580	19.42	596
1980	103,557.53	60,689	65,986	37,572	19.87	1,891
1981	178,949.81	103,157	112,161	66,789	20.33	3,285
1982	170,565.75	120,761	131,301	39,265	18.25	2,152
1983	36,084.80	25,281	27,488	8,597	18.48	465
1984	82,281.22	57,013	61,989	20,292	18.73	1,083
1985	181,687.68	123,657	134,450	47,238	19.36	2,440
1986	197,454.14	132,729	144,314	53,141	19.63	2,707
1987	147,434.92	97,794	106,329	41,105	19.92	2,064
1988	155,545.80	101,743	110,623	44,923	20.23	2,221
1989	336,479.54	216,827	235,752	100,728	20.55	4,902
1990	137,548.78	87,261	94,877	42,672	20.89	2,043
1991	194,538.21	121,372	131,965	62,573	21.25	2,945
1992	284,183.63	175,199	190,490	93,693	21.31	4,397
1993	86,948.76	52,621	57,214	29,735	21.69	1,371
1994	182,054.49	108,031	117,460	64,595	22.10	2,923
1995	398,609.81	231,672	251,892	146,717	22.52	6,515
1996	822,303.05	470,111	511,142	311,161	22.66	13,732
1997	295,816.74	165,273	179,698	116,119	23.10	5,027
1998	505,794.39	277,175	301,367	204,427	23.30	8,774
1999	147,121.40	78,975	85,868	61,253	23.51	2,605
2000	648,917.35	338,994	368,581	280,336	24.00	11,681
2001	424,313.08	216,400	235,287	189,026	24.26	7,792
2002	261,553.24	130,018	141,366	120,187	24.53	4,900
2003	2,209,813.24	1,068,666	1,161,939	1,047,874	24.83	42,202
2004	1,209,697.89	567,953	617,524	592,174	25.14	23,555
2005	893,779.32	406,491	441,970	451,810	25.48	17,732
2006	868,994.76	383,574	417,052	451,942	25.62	17,640

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2007	740,357.19	314,948	342,437	397,920	26.00	15,305
2008	1,443,964.43	598,379	650,606	793,359	26.14	30,350
2009	548,983.15	219,044	238,162	310,821	26.36	11,791
2010	583,886.38	222,577	242,004	341,883	26.79	12,762
2011	2,483,868.83	904,625	983,581	1,500,288	27.06	55,443
2012	2,434,829.25	847,321	921,275	1,513,554	27.17	55,707
2013	965,238.41	317,950	345,701	619,538	27.48	22,545
2014	1,514,604.17	471,345	512,484	1,002,120	27.66	36,230
2015	5,060,764.87	1,472,683	1,601,219	3,459,546	28.02	123,467
2016	3,456,627.15	936,400	1,018,129	2,438,498	28.26	86,288
2017	3,146,689.14	789,190	858,071	2,288,618	28.38	80,642
2018	1,748,187.04	399,636	434,516	1,313,671	28.68	45,804
2019	5,087,819.87	1,049,108	1,140,674	3,947,145	28.87	136,721
2020	3,173,810.31	581,759	632,535	2,541,275	28.96	87,751
2021	7,830,374.82	1,245,030	1,353,697	6,476,678	29.10	222,566
2022	8,141,270.54	1,084,417	1,179,065	6,962,205	29.28	237,780
2023	8,106,007.05	862,479	937,756	7,168,251	29.39	243,901
2024	2,927,319.43	228,916	248,896	2,678,424	29.45	90,948
2025	4,332,095.07	210,540	228,916	4,103,179	29.36	139,754
2026	17,656,301.35	296,626	322,516	17,333,786	29.18	594,030
	93,699,449.60	19,792,941	21,519,558	72,179,892		2,547,054
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1929	61.54	62	62			
1930	110.50	110	111			
1932	198.40	196	198			
1952	2,326.37	1,930	2,022	304	8.18	37
1953	1,159.51	952	997	162	8.57	19
1954	1,182.96	962	1,008	175	8.96	20
1955	9,007.40	7,251	7,597	1,410	9.36	151
1956	488.98	390	409	80	9.75	8
1957	73,249.30	57,760	60,517	12,732	10.15	1,254
1958	56,774.36	44,296	46,410	10,364	10.55	982
1959	12,815.05	9,892	10,364	2,451	10.95	224
1960	32,578.68	24,875	26,062	6,516	11.35	574
1961	23,792.24	17,963	18,820	4,972	11.76	423
1962	27,398.14	20,457	21,433	5,965	12.16	491

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1963	57,531.01	42,465	44,492	13,039	12.57	1,037
1964	58,402.86	42,610	44,644	13,759	12.98	1,060
1965	115,141.46	82,997	86,959	28,183	13.40	2,103
1966	93,331.98	66,479	69,652	23,680	13.81	1,715
1967	110,026.25	77,408	81,103	28,923	14.23	2,033
1968	158,290.48	109,979	115,229	43,062	14.65	2,939
1969	419,906.46	288,073	301,824	118,083	15.07	7,836
1970	356,710.96	241,597	253,129	103,582	15.49	6,687
1971	176,824.59	118,177	123,818	53,007	15.92	3,330
1972	61,851.50	40,784	42,731	19,121	16.35	1,169
1973	159,984.32	104,057	109,024	50,960	16.78	3,037
1974	60,273.21	38,663	40,509	19,765	17.21	1,148
1975	28,089.60	17,761	18,609	9,481	17.65	537
1976	50,228.55	31,298	32,792	17,437	18.09	964
1977	213,255.97	130,931	137,181	76,075	18.53	4,106
1978	8,194.49	4,956	5,193	3,002	18.97	158
1979	28,377.51	16,897	17,704	10,674	19.42	550
1980	113,602.19	66,575	69,753	43,849	19.87	2,207
1981	455,647.68	262,663	275,201	180,447	20.33	8,876
1982	329,481.57	233,273	244,408	85,074	18.25	4,662
1983	224,843.77	157,526	165,045	59,799	18.48	3,236
1984	56,217.87	38,953	40,812	15,406	18.73	823
1985	104,484.65	71,112	74,506	29,978	19.36	1,548
1986	133,356.05	89,642	93,921	39,435	19.63	2,009
1987	262,277.13	173,968	182,272	80,005	19.92	4,016
1988	120,060.83	78,532	82,281	37,780	20.23	1,868
1989	200,777.62	129,381	135,557	65,221	20.55	3,174
1990	106,489.73	67,557	70,782	35,708	20.89	1,709
1991	79,883.34	49,839	52,218	27,665	21.25	1,302
1992	147,889.36	91,174	95,526	52,363	21.31	2,457
1993	179,468.47	108,614	113,799	65,670	21.69	3,028
1994	426,086.05	252,839	264,908	161,178	22.10	7,293
1995	293,273.92	170,451	178,587	114,687	22.52	5,093
1996	198,687.31	113,590	119,012	79,675	22.66	3,516
1997	426,382.07	238,220	249,591	176,791	23.10	7,653
1998	448,883.20	245,988	257,730	191,153	23.30	8,204
1999	143,541.38	77,053	80,731	62,810	23.51	2,672
2000	131,039.67	68,455	71,723	59,317	24.00	2,472
2001	715,985.10	365,152	382,582	333,403	24.26	13,743
2002	109,500.33	54,433	57,031	52,469	24.53	2,139
2003	118,145.44	57,135	59,862	58,283	24.83	2,347

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2004	494,355.19	232,100	243,179	251,176	25.14	9,991
2005	286,059.04	130,100	136,310	149,749	25.48	5,877
2006	251,662.47	111,084	116,386	135,276	25.62	5,280
2007	893,372.04	380,040	398,181	495,191	26.00	19,046
2008	792,986.92	328,614	344,300	448,687	26.14	17,165
2009	101,289.46	40,414	42,343	58,946	26.36	2,236
2010	91,222.24	34,774	36,434	54,788	26.79	2,045
2011	1,502,822.32	547,328	573,454	929,369	27.06	34,345
2012	453,197.27	157,713	165,241	287,956	27.17	10,598
2013	22,535.66	7,423	7,777	14,758	27.48	537
2014	3,025,142.56	941,424	986,361	2,038,781	27.66	73,709
2015	1,486,865.77	432,678	453,331	1,033,535	28.02	36,886
2016	1,044,520.78	282,961	296,468	748,053	28.26	26,470
2017	1,886,700.74	473,185	495,772	1,390,929	28.38	49,011
2018	10,747,678.42	2,456,919	2,574,196	8,173,483	28.68	284,989
2019	4,126,582.91	850,901	891,517	3,235,066	28.87	112,056
2020	4,240,028.18	777,197	814,295	3,425,733	28.96	118,292
2021	2,164,064.27	344,086	360,510	1,803,554	29.10	61,978
2022	7,506,837.71	999,911	1,047,640	6,459,198	29.28	220,601
2023	2,213,061.08	235,470	246,710	1,966,351	29.39	66,905
2024	1,667,618.76	130,408	136,633	1,530,986	29.45	51,986
2025	1,841,668.03	89,505	93,777	1,747,891	29.36	59,533
2026	2,560,793.85	43,021	45,075	2,515,719	29.18	86,214
	57,324,635.03	14,931,609	15,644,329	41,680,306		1,496,389
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	55.14	55	55			
1911	75.86	76	76			
1922	243.54	244	244			
1926	225.00	225	225			
1927	198.83	199	199			
1928	1,818.42	1,818	1,818			
1929	56.04	56	56			
1930	19.77	20	20			
1931	24.71	25	25			
1932	104.17	103	104			
1934	271.19	263	271			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1935	276.35	266	276			
1936	444.55	425	445			
1937	1,093.24	1,037	1,093			
1938	456.48	429	456			
1939	441.56	412	442			
1940	100.92	93	101			
1941	245.91	226	246			
1945	105.54	93	104	2	5.48	
1947	488.45	425	475	14	6.25	2
1948	537.62	463	517	20	6.63	3
1949	70.39	60	67	3	7.02	
1950	50.60	43	48	3	7.40	
1951	43.23	36	40	3	7.79	
1952	322.36	267	298	24	8.18	3
1953	319.38	262	293	27	8.57	3
1954	1,086.76	884	988	99	8.96	11
1955	525.63	423	473	53	9.36	6
1956	7,571.85	6,034	6,742	830	9.75	85
1957	7,404.34	5,839	6,524	880	10.15	87
1958	2,925.63	2,283	2,551	375	10.55	36
1959	1,733.67	1,338	1,495	239	10.95	22
1960	4,312.80	3,293	3,680	633	11.35	56
1961	4,355.00	3,288	3,674	681	11.76	58
1962	3,945.67	2,946	3,292	654	12.16	54
1963	7,733.07	5,708	6,378	1,355	12.57	108
1964	7,713.27	5,627	6,287	1,426	12.98	110
1965	26,131.34	18,836	21,047	5,085	13.40	379
1966	17,000.59	12,109	13,530	3,470	13.81	251
1967	8,193.22	5,764	6,441	1,753	14.23	123
1968	12,037.15	8,363	9,345	2,693	14.65	184
1969	12,235.51	8,394	9,379	2,856	15.07	190
1970	8,649.96	5,859	6,547	2,103	15.49	136
1971	19,864.87	13,276	14,834	5,031	15.92	316
1972	17,242.49	11,369	12,703	4,539	16.35	278
1973	16,767.53	10,906	12,186	4,581	16.78	273
1974	42,166.85	27,048	30,223	11,944	17.21	694
1975	7,737.38	4,892	5,466	2,271	17.65	129
1976	24,852.00	15,486	17,304	7,548	18.09	417
1977	9,953.97	6,111	6,828	3,126	18.53	169
1978	40,166.30	24,292	27,143	13,023	18.97	687
1979	29,002.11	17,268	19,295	9,707	19.42	500

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1980	37,944.88	22,237	24,847	13,098	19.87	659
1981	103,619.82	59,733	66,744	36,876	20.33	1,814
1982	85,784.41	60,735	67,864	17,921	18.25	982
1983	60,513.04	42,395	47,371	13,142	18.48	711
1984	50,194.70	34,780	38,862	11,333	18.73	605
1985	95,364.34	64,905	72,523	22,841	19.36	1,180
1986	85,225.83	57,289	64,013	21,213	19.63	1,081
1987	80,514.60	53,405	59,673	20,841	19.92	1,046
1988	72,833.48	47,640	53,232	19,602	20.23	969
1989	107,966.68	69,574	77,740	30,227	20.55	1,471
1990	75,933.12	48,172	53,826	22,107	20.89	1,058
1991	128,138.60	79,946	89,329	38,809	21.25	1,826
1992	139,524.71	86,017	96,113	43,412	21.31	2,037
1993	101,952.11	61,701	68,943	33,009	21.69	1,522
1994	130,073.51	77,186	86,245	43,828	22.10	1,983
1995	233,066.82	135,458	151,357	81,710	22.52	3,628
1996	174,244.04	99,615	111,307	62,937	22.66	2,777
1997	160,578.83	89,715	100,245	60,334	23.10	2,612
1998	255,961.71	140,267	156,730	99,231	23.30	4,259
1999	131,780.79	70,740	79,043	52,738	23.51	2,243
2000	467,772.87	244,365	273,046	194,726	24.00	8,114
2001	173,913.60	88,696	99,106	74,807	24.26	3,084
2002	363,245.07	180,569	201,763	161,483	24.53	6,583
2003	210,832.72	101,959	113,926	96,907	24.83	3,903
2004	272,679.86	128,023	143,049	129,631	25.14	5,156
2005	433,498.29	197,155	220,295	213,203	25.48	8,367
2006	204,656.35	90,335	100,938	103,719	25.62	4,048
2007	375,497.74	159,737	178,485	197,012	26.00	7,577
2008	402,809.42	166,924	186,516	216,293	26.14	8,274
2009	345,387.94	137,810	153,985	191,403	26.36	7,261
2010	115,325.82	43,962	49,122	66,204	26.79	2,471
2011	720,198.32	262,296	293,082	427,116	27.06	15,784
2012	334,855.50	116,530	130,207	204,648	27.17	7,532
2013	891,631.39	293,703	328,175	563,456	27.48	20,504
2014	1,768,472.56	550,349	614,944	1,153,529	27.66	41,704
2015	2,788,841.86	811,553	906,806	1,882,036	28.02	67,168
2016	905,530.84	245,308	274,100	631,431	28.26	22,344
2017	648,536.68	162,653	181,744	466,793	28.38	16,448
2018	232,900.64	53,241	59,490	173,411	28.68	6,046
2019	408,138.03	84,158	94,036	314,102	28.87	10,880
2020	1,608,643.58	294,864	329,472	1,279,171	28.96	44,170

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2021	4,774,027.39	759,070	848,163	3,925,865	29.10	134,909
2022	3,525,680.25	469,621	524,741	3,000,939	29.28	102,491
2023	2,359,143.09	251,013	280,475	2,078,668	29.39	70,727
2024	4,673,304.99	365,452	408,345	4,264,960	29.45	144,820
2025	1,535,912.81	74,645	83,406	1,452,507	29.36	49,472
2026	7,225,361.90	121,386	135,633	7,089,729	29.18	242,965
	40,427,413.74	8,092,144	9,041,406	31,386,008		1,102,635
	191,451,498.37	42,816,694	46,205,293	145,246,206		5,146,078

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.2 2.69

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	1,330.58	1,179	1,289	41	5.11	8
1956	21,290.16	18,627	20,372	918	5.63	163
1957	5,372.45	4,668	5,105	267	5.90	45
1958	8,518.07	7,348	8,036	482	6.18	78
1959	4,392.86	3,762	4,114	278	6.46	43
1960	27,087.71	23,031	25,189	1,899	6.74	282
1961	1,916.00	1,617	1,768	148	7.03	21
1962	1,339.47	1,121	1,226	113	7.33	15
1963	30.71	26	28	2	7.62	
1965	41,595.76	33,979	37,162	4,433	8.24	538
1966	19,579.16	15,855	17,340	2,239	8.56	262
1967	14,375.52	11,539	12,620	1,755	8.88	198
1968	818.29	651	712	106	9.21	12
1969	15,932.36	12,555	13,731	2,201	9.54	231
1970	553.00	431	471	82	9.89	8
1972	36,690.90	28,040	30,667	6,024	10.61	568
1973	38,195.02	28,875	31,580	6,615	10.98	602
1974	19,018.54	14,217	15,549	3,470	11.36	305
1975	25,329.73	18,710	20,463	4,867	11.76	414
1976	12,818.60	9,355	10,231	2,587	12.16	213
1977	148.01	107	117	31	12.57	2
1978	4,242.67	3,017	3,300	943	13.00	73
1979	1,542.38	1,082	1,183	359	13.44	27
1980	4,638.03	3,206	3,506	1,132	13.89	81
1981	80,176.22	54,609	59,725	20,451	14.35	1,425
1982	141,945.62	109,298	119,538	22,408	13.22	1,695
1983	6,800.47	5,177	5,662	1,138	13.57	84
1984	199,926.07	150,344	164,430	35,496	13.93	2,548
1985	433,461.53	320,068	350,055	83,407	14.61	5,709
1986	265,735.11	193,588	211,725	54,010	15.00	3,601
1987	791,585.85	568,596	621,867	169,718	15.39	11,028
1988	18,764.80	13,278	14,522	4,243	15.81	268
1989	37,807.02	26,336	28,803	9,004	16.22	555
1990	128,484.87	88,025	96,272	32,213	16.66	1,934
1991	257,739.07	173,536	189,794	67,945	17.10	3,973
1992	198,243.74	131,039	143,316	54,928	17.56	3,128
1993	32,985.36	21,388	23,392	9,594	18.03	532
1994	6,197.62	3,937	4,306	1,892	18.51	102
1995	265,285.40	164,981	180,438	84,847	19.00	4,466
1996	390,043.61	237,147	259,365	130,678	19.50	6,701
1998	8,401.63	4,865	5,321	3,081	20.53	150

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
2003	278,252.13	140,378	153,530	124,722	22.83	5,463
2009	23,277.53	9,451	10,336	12,941	25.60	506
2014	78,923.32	24,466	26,758	52,165	27.82	1,875
2016	168,831.19	45,551	49,819	119,013	28.41	4,189
2017	32,073.62	7,954	8,699	23,374	28.81	811
2019	90,422.23	18,446	20,174	70,248	29.26	2,401
2020	191,930.65	34,682	37,931	153,999	29.47	5,226
2021	1,737,045.60	272,369	297,887	1,439,159	29.59	48,637
2022	16,273,209.43	2,144,809	2,345,755	13,927,455	29.63	470,046
2023	11,855,743.76	1,261,451	1,379,635	10,476,108	29.39	356,451
2024	909,861.73	72,334	79,111	830,751	28.95	28,696
2025	14,466,646.64	734,906	803,759	13,662,888	28.00	487,960
	49,676,557.80	7,276,007	7,957,691	41,718,867		1,464,349
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,267	14,060	2,721	6.74	404
1962	29,310.05	24,536	24,179	5,131	7.33	700
1963	28,716.91	23,854	23,507	5,210	7.62	684
1964	1,610.71	1,327	1,308	303	7.93	38
1965	15,073.47	12,313	12,134	2,940	8.24	357
1966	113,790.28	92,145	90,805	22,985	8.56	2,685
1967	4,284.76	3,439	3,389	896	8.88	101
1968	122,380.44	97,333	95,918	26,463	9.21	2,873
1969	114,417.87	90,161	88,850	25,568	9.54	2,680
1970	18,752.91	14,631	14,418	4,335	9.89	438
1971	13,464.24	10,400	10,249	3,215	10.24	314
1972	2,349.36	1,795	1,769	580	10.61	55
1974	21,308.55	15,929	15,697	5,611	11.36	494
1975	37,036.13	27,357	26,959	10,077	11.76	857
1977	2,043.72	1,473	1,452	592	12.57	47
1978	2,934.41	2,087	2,057	878	13.00	68
1979	1,353.24	949	935	418	13.44	31
1980	47,010.45	32,500	32,027	14,983	13.89	1,079
1981	687,198.17	468,058	461,251	225,947	14.35	15,745
1982	114,036.20	87,808	86,531	27,505	13.22	2,081
1983	6,538.51	4,977	4,905	1,634	13.57	120
1984	1,848.56	1,390	1,370	479	13.93	34

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1985	33,053.50	24,407	24,052	9,001	14.61	616
1986	796.80	580	572	225	15.00	15
1987	900.93	647	638	263	15.39	17
1988	228,712.92	161,837	159,483	69,229	15.81	4,379
1989	5,767.35	4,018	3,960	1,808	16.22	111
1990	8,208.45	5,624	5,542	2,666	16.66	160
1991	15,153.04	10,203	10,055	5,098	17.10	298
1992	1,292.66	854	842	451	17.56	26
1993	49,169.36	31,881	31,417	17,752	18.03	985
1994	82,378.57	52,335	51,574	30,805	18.51	1,664
1995	42,532.19	26,451	26,066	16,466	19.00	867
1996	44,580.63	27,105	26,711	17,870	19.50	916
1997	515,665.73	306,202	301,749	213,917	20.01	10,691
1998	118,063.23	68,370	67,376	50,688	20.53	2,469
1999	58,548.09	33,185	32,702	25,846	20.83	1,241
2000	69,703.96	38,421	37,862	31,842	21.37	1,490
2001	173,986.69	93,135	91,781	82,206	21.92	3,750
2002	184,888.86	96,401	94,999	89,890	22.26	4,038
2003	175,733.00	88,657	87,368	88,365	22.83	3,871
2004	75,956.41	37,014	36,476	39,481	23.41	1,687
2005	48,587.58	22,924	22,591	25,997	23.79	1,093
2006	162,733.73	73,816	72,743	89,991	24.39	3,690
2007	9,461.70	4,135	4,075	5,387	24.80	217
2008	460,995.77	195,278	192,438	268,558	25.17	10,670
2009	53,996.90	21,923	21,604	32,393	25.60	1,265
2010	265,809.52	103,081	101,582	164,228	26.05	6,304
2011	1,348,202.00	497,352	490,119	858,083	26.52	32,356
2012	963,681.06	336,710	331,813	631,868	27.00	23,403
2013	309,369.28	102,339	100,851	208,519	27.31	7,635
2014	7,850,809.11	2,433,751	2,398,358	5,452,451	27.82	195,990
2015	784,772.22	227,427	224,120	560,653	28.18	19,895
2018	1.37			1	29.09	
2019	2,147,672.02	438,125	431,754	1,715,919	29.26	58,644
2020	350,661.95	63,365	62,444	288,218	29.47	9,780
2021	214,987.16	33,710	33,220	181,767	29.59	6,143
2022	5,163,458.24	680,544	670,647	4,492,811	29.63	151,630
2023	4,648,863.73	494,639	487,446	4,161,418	29.39	141,593
2024	667,067.84	53,032	52,261	614,807	28.95	21,237
2025	820,714.65	41,692	41,086	779,629	28.00	27,844
	29,559,177.51	7,959,899	7,844,141	21,715,037		790,565

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	266.15	236	208	58	5.11	11
1956	1,419.60	1,242	1,095	324	5.63	58
1958	1,154.96	996	879	276	6.18	45
1959	352.50	302	266	86	6.46	13
1960	3,229.10	2,745	2,421	808	6.74	120
1965	2,958.56	2,417	2,132	827	8.24	100
1966	3,788.99	3,068	2,706	1,083	8.56	127
1967	2,785.64	2,236	1,972	813	8.88	92
1969	2,147.66	1,692	1,492	655	9.54	69
1971	481.68	372	328	154	10.24	15
1972	1,415.71	1,082	954	461	10.61	43
1973	1,983.52	1,500	1,323	660	10.98	60
1974	1,411.62	1,055	931	481	11.36	42
1976	3,626.30	2,646	2,334	1,292	12.16	106
1978	10,681.17	7,595	6,699	3,982	13.00	306
1980	703.40	486	429	275	13.89	20
1981	2,492.78	1,698	1,498	995	14.35	69
1987	1,548.80	1,113	982	567	15.39	37
1988	1,790.48	1,267	1,118	673	15.81	43
1991	417.27	281	248	169	17.10	10
1994	551.52	350	309	243	18.51	13
2012	1,055.35	369	325	730	27.00	27
2013	422.81	140	123	299	27.31	11
2019	181,294.79	36,984	32,621	148,674	29.26	5,081
2023	653,815.24	69,566	61,359	592,456	29.39	20,158
2024	1,265,047.41	100,571	88,707	1,176,341	28.95	40,634
2025	397,245.69	20,180	17,799	379,446	28.00	13,552
	2,544,088.70	262,189	231,259	2,312,830		80,862
	81,779,824.01	15,498,095	16,033,091	65,746,734		2,335,776

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.1 2.86

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	2,793.87	2,605	2,417	377	3.05	124
1955	16,307.64	15,097	14,006	2,302	3.34	689
1956	36,014.93	33,110	30,717	5,298	3.63	1,460
1957	49,914.06	45,566	42,272	7,642	3.92	1,949
1958	73,912.23	66,997	62,154	11,758	4.21	2,793
1959	140,376.41	126,339	117,207	23,170	4.50	5,149
1960	203,240.25	181,607	168,480	34,761	4.79	7,257
1961	228,952.21	203,055	188,377	40,575	5.09	7,972
1962	220,767.23	194,372	180,322	40,445	5.38	7,518
1963	258,591.19	226,009	209,672	48,919	5.67	8,628
1964	253,264.37	219,664	203,786	49,479	5.97	8,288
1965	319,700.11	275,083	255,199	64,501	6.28	10,271
1966	457,201.67	390,249	362,040	95,162	6.59	14,440
1967	425,367.66	360,146	334,113	91,255	6.90	13,225
1968	503,327.54	422,574	392,028	111,299	7.22	15,415
1969	534,866.83	445,127	412,951	121,916	7.55	16,148
1970	533,676.38	440,107	408,294	125,382	7.89	15,891
1971	599,892.28	490,046	454,623	145,269	8.24	17,630
1972	843,862.88	682,778	633,423	210,439	8.59	24,498
1973	1,049,255.19	840,338	779,594	269,661	8.96	30,096
1974	1,097,706.34	869,866	806,988	290,719	9.34	31,126
1975	719,746.66	564,123	523,345	196,401	9.73	20,185
1976	798,929.96	619,083	574,333	224,597	10.13	22,171
1977	1,545,031.04	1,182,814	1,097,314	447,717	10.55	42,438
1978	1,434,739.72	1,084,979	1,006,551	428,188	10.97	39,033
1979	2,651,020.69	1,978,828	1,835,789	815,232	11.41	71,449
1980	4,476,701.20	3,296,822	3,058,512	1,418,190	11.86	119,578
1981	4,546,003.43	3,300,398	3,061,829	1,484,174	12.33	120,371
1982	4,012,630.84	3,178,405	2,948,654	1,063,976	11.61	91,643
1983	2,973,497.71	2,327,654	2,159,400	814,098	12.00	67,842
1984	3,152,695.25	2,437,664	2,261,458	891,238	12.39	71,932
1985	3,627,779.00	2,768,358	2,568,248	1,059,531	12.81	82,711
1986	3,920,257.32	2,950,778	2,737,481	1,182,776	13.22	89,469
1987	4,651,262.74	3,432,167	3,184,073	1,467,190	13.94	105,250
1988	5,991,670.02	4,354,746	4,039,964	1,951,706	14.38	135,724
1989	8,531,274.38	6,101,567	5,660,516	2,870,758	14.83	193,578
1990	9,484,287.13	6,669,351	6,187,258	3,297,029	15.30	215,492
1991	8,604,614.11	5,944,928	5,515,200	3,089,415	15.77	195,905
1992	8,590,287.45	5,825,933	5,404,806	3,185,481	16.25	196,030
1993	5,882,133.85	3,911,619	3,628,868	2,253,266	16.75	134,523
1994	11,607,002.61	7,560,802	7,014,270	4,592,732	17.26	266,091

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1995	12,345,713.20	7,870,392	7,301,482	5,044,232	17.77	283,862
1996	10,262,964.29	6,395,879	5,933,554	4,329,411	18.29	236,709
1997	11,486,624.38	6,988,462	6,483,302	5,003,323	18.83	265,710
1998	9,193,947.75	5,453,850	5,059,619	4,134,329	19.37	213,440
1999	9,358,575.74	5,406,449	5,015,644	4,342,931	19.92	218,019
2000	9,832,272.07	5,523,770	5,124,485	4,707,787	20.48	229,872
2001	9,706,335.10	5,318,101	4,933,683	4,772,652	20.83	229,124
2002	10,211,387.63	5,423,268	5,031,248	5,180,140	21.41	241,950
2003	8,049,700.59	4,135,936	3,836,970	4,212,730	22.00	191,488
2004	11,041,623.04	5,478,853	5,082,815	5,958,808	22.59	263,781
2005	9,279,175.57	4,436,374	4,115,691	5,163,484	23.20	222,564
2006	10,096,066.05	4,661,354	4,324,409	5,771,657	23.61	244,458
2007	10,041,639.41	4,446,438	4,125,028	5,916,612	24.23	244,185
2008	13,182,511.43	5,657,934	5,248,951	7,933,561	24.60	322,502
2009	13,431,571.43	5,500,229	5,102,646	8,328,926	25.24	329,989
2010	13,887,967.53	5,407,975	5,017,060	8,870,907	25.87	342,903
2011	21,307,572.22	7,892,325	7,321,829	13,985,743	26.34	530,970
2012	31,356,662.41	10,956,018	10,164,063	21,192,599	27.00	784,911
2013	40,650,159.91	13,390,163	12,422,257	28,227,903	27.48	1,027,216
2014	39,555,973.62	12,214,885	11,331,933	28,224,040	27.98	1,008,722
2015	41,319,876.77	11,879,465	11,020,759	30,299,118	28.50	1,063,127
2016	45,058,337.17	11,967,494	11,102,425	33,955,912	29.03	1,169,683
2017	42,734,872.67	10,393,121	9,641,855	33,093,017	29.56	1,119,520
2018	48,795,157.00	10,783,730	10,004,229	38,790,928	29.96	1,294,757
2019	64,708,056.83	12,760,429	11,838,043	52,870,014	30.52	1,732,307
2020	56,583,898.15	9,822,965	9,112,913	47,470,985	30.95	1,533,796
2021	74,572,106.57	11,155,987	10,349,578	64,222,529	31.26	2,054,463
2022	94,566,790.39	11,783,022	10,931,288	83,635,503	31.60	2,646,693
2023	98,679,602.52	9,769,281	9,063,110	89,616,493	31.84	2,814,588
2024	65,952,901.09	4,814,562	4,466,542	61,486,359	31.75	1,936,578
2025	54,709,076.24	2,494,734	2,314,402	52,394,674	31.39	1,669,152
2026	86,682,862.96	1,438,936	1,334,923	85,347,940	29.62	2,881,429
	1,183,692,538.11	317,644,135	294,683,265	889,009,273		31,870,450
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1938	1,209.24	1,209	1,209			
1939	5,041.71	5,042	5,042			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1940	5,621.76	5,622	5,622			
1941	5,821.34	5,821	5,821			
1942	3,853.82	3,854	3,854			
1943	2,911.51	2,897	2,857	55	0.23	55
1944	4,922.17	4,885	4,817	105	0.34	105
1945	8,342.42	8,233	8,118	224	0.59	224
1946	14,473.22	14,200	14,002	471	0.85	471
1947	15,797.90	15,405	15,190	607	1.12	542
1948	19,487.27	18,890	18,627	860	1.38	623
1949	17,692.12	17,043	16,806	886	1.65	537
1950	25,469.01	24,382	24,042	1,427	1.92	743
1951	19,454.28	18,503	18,245	1,209	2.20	550
1952	1,476,667.34	1,395,288	1,375,859	100,808	2.48	40,648
1953	15,508.82	14,554	14,351	1,157	2.77	418
1954	22,185.18	20,681	20,393	1,792	3.05	588
1955	37,781.78	34,978	34,491	3,291	3.34	985
1956	43,744.33	40,215	39,655	4,089	3.63	1,126
1957	61,085.56	55,764	54,988	6,098	3.92	1,556
1958	90,124.69	81,693	80,555	9,569	4.21	2,273
1959	143,680.88	129,313	127,512	16,169	4.50	3,593
1960	126,510.04	113,044	111,470	15,040	4.79	3,140
1961	152,847.97	135,559	133,671	19,177	5.09	3,768
1962	278,612.11	245,301	241,885	36,727	5.38	6,827
1963	351,857.32	307,523	303,241	48,616	5.67	8,574
1964	476,396.41	413,193	407,439	68,957	5.97	11,551
1965	569,195.83	489,759	482,939	86,257	6.28	13,735
1966	631,102.11	538,684	531,183	99,919	6.59	15,162
1967	740,941.52	627,333	618,598	122,344	6.90	17,731
1968	961,517.92	807,252	796,011	165,507	7.22	22,923
1969	1,017,516.15	846,797	835,006	182,510	7.55	24,174
1970	1,169,565.74	964,506	951,076	218,490	7.89	27,692
1971	395,710.34	323,252	318,751	76,959	8.24	9,340
1972	667,478.09	540,063	532,543	134,935	8.59	15,708
1973	1,250,708.69	1,001,680	987,732	262,977	8.96	29,350
1974	1,287,851.63	1,020,545	1,006,334	281,517	9.34	30,141
1975	1,101,449.71	863,294	851,273	250,177	9.73	25,712
1976	1,335,533.26	1,034,891	1,020,481	315,053	10.13	31,101
1977	1,703,248.15	1,303,939	1,285,782	417,466	10.55	39,570
1978	1,297,629.65	981,293	967,629	330,001	10.97	30,082
1979	1,639,091.47	1,223,483	1,206,447	432,645	11.41	37,918
1980	1,862,210.42	1,371,406	1,352,310	509,901	11.86	42,993

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1981	1,708,667.95	1,240,493	1,223,220	485,448	12.33	39,371
1982	1,401,581.67	1,110,193	1,094,734	306,848	11.61	26,430
1983	1,076,642.79	842,796	831,060	245,582	12.00	20,465
1984	1,531,965.55	1,184,516	1,168,022	363,943	12.39	29,374
1985	1,962,826.42	1,497,833	1,476,976	485,850	12.81	37,927
1986	2,462,022.06	1,853,164	1,827,359	634,663	13.22	48,008
1987	3,266,506.32	2,410,355	2,376,792	889,714	13.94	63,825
1988	4,348,017.46	3,160,139	3,116,135	1,231,882	14.38	85,666
1989	4,123,806.34	2,949,346	2,908,278	1,215,529	14.83	81,964
1990	4,538,353.13	3,191,370	3,146,932	1,391,422	15.30	90,943
1991	3,330,234.45	2,300,859	2,268,821	1,061,414	15.77	67,306
1992	4,123,744.52	2,796,724	2,757,781	1,365,964	16.25	84,059
1993	4,365,898.41	2,903,322	2,862,894	1,503,004	16.75	89,732
1994	4,449,859.03	2,898,638	2,858,276	1,591,583	17.26	92,212
1995	5,115,174.50	3,260,924	3,215,517	1,899,657	17.77	106,902
1996	4,996,064.20	3,113,547	3,070,192	1,925,872	18.29	105,296
1997	6,059,557.00	3,686,634	3,635,299	2,424,258	18.83	128,744
1998	5,505,206.31	3,265,688	3,220,215	2,284,992	19.37	117,966
1999	3,990,683.85	2,305,418	2,273,316	1,717,368	19.92	86,213
2000	3,198,516.21	1,796,926	1,771,905	1,426,612	20.48	69,659
2001	5,865,889.09	3,213,921	3,169,169	2,696,721	20.83	129,463
2002	4,902,015.15	2,603,460	2,567,208	2,334,807	21.41	109,052
2003	5,266,321.85	2,705,836	2,668,158	2,598,163	22.00	118,098
2004	11,305,730.18	5,609,903	5,531,788	5,773,943	22.59	255,597
2005	7,324,540.13	3,501,863	3,453,101	3,871,439	23.20	166,872
2006	4,296,991.37	1,983,921	1,956,296	2,340,696	23.61	99,140
2007	5,904,496.33	2,614,511	2,578,105	3,326,391	24.23	137,284
2008	6,331,699.21	2,717,565	2,679,724	3,651,975	24.60	148,454
2009	6,332,325.17	2,593,087	2,556,979	3,775,346	25.24	149,578
2010	4,206,356.37	1,637,955	1,615,147	2,591,209	25.87	100,163
2011	7,297,788.82	2,703,101	2,665,461	4,632,327	26.34	175,867
2012	9,186,533.88	3,209,775	3,165,080	6,021,454	27.00	223,017
2013	9,082,014.08	2,991,615	2,949,958	6,132,056	27.48	223,146
2014	9,634,028.61	2,974,988	2,933,563	6,700,466	27.98	239,473
2015	13,986,535.86	4,021,129	3,965,137	10,021,399	28.50	351,628
2016	15,529,663.32	4,124,679	4,067,245	11,462,419	29.03	394,847
2017	17,068,932.48	4,151,164	4,093,361	12,975,572	29.56	438,957
2018	19,326,871.19	4,271,239	4,211,764	15,115,107	29.96	504,510
2019	23,467,858.97	4,627,862	4,563,421	18,904,438	30.52	619,411
2020	18,116,964.36	3,145,105	3,101,311	15,015,654	30.95	485,158
2021	32,154,440.68	4,810,304	4,743,323	27,411,118	31.26	876,875

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2022	29,005,614.41	3,614,100	3,563,775	25,441,839	31.60	805,121
2023	25,286,288.92	2,503,343	2,468,485	22,817,804	31.84	716,640
2024	16,371,308.52	1,195,106	1,178,465	15,192,844	31.75	478,515
2025	19,159,962.73	873,694	861,528	18,298,435	31.39	582,938
2026	29,472,227.15	489,239	482,427	28,989,801	29.62	978,724
	448,496,577.88	143,728,619	141,727,560	306,769,018		11,482,819
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1962	3,240.46	2,853	2,750	490	5.38	91
1963	7,070.00	6,179	5,956	1,114	5.67	196
1964	7,689.17	6,669	6,428	1,261	5.97	211
1965	7,822.47	6,731	6,488	1,334	6.28	212
1966	17,752.79	15,153	14,606	3,147	6.59	478
1967	21,913.23	18,553	17,883	4,030	6.90	584
1968	20,331.47	17,069	16,453	3,878	7.22	537
1969	23,339.22	19,423	18,722	4,617	7.55	612
1970	38,634.57	31,861	30,711	7,923	7.89	1,004
1971	58,364.24	47,677	45,956	12,408	8.24	1,506
1972	34,831.39	28,182	27,165	7,666	8.59	892
1973	75,060.26	60,115	57,945	17,115	8.96	1,910
1974	113,798.19	90,178	86,923	26,875	9.34	2,877
1975	81,855.56	64,157	61,842	20,014	9.73	2,057
1976	42,243.09	32,734	31,553	10,690	10.13	1,055
1977	56,594.44	43,326	41,762	14,832	10.55	1,406
1978	51,597.43	39,019	37,611	13,987	10.97	1,275
1979	127,812.24	95,404	91,961	35,851	11.41	3,142
1980	301,262.96	221,862	213,855	87,408	11.86	7,370
1981	296,942.01	215,580	207,800	89,142	12.33	7,230
1982	251,522.36	199,231	192,041	59,482	11.61	5,123
1983	362,896.30	284,075	273,823	89,074	12.00	7,423
1984	469,000.68	362,631	349,543	119,457	12.39	9,641
1985	534,744.97	408,064	393,337	141,408	12.81	11,039
1986	694,263.12	522,572	503,712	190,551	13.22	14,414
1987	671,902.65	495,797	477,903	193,999	13.94	13,917
1988	1,127,205.78	819,253	789,686	337,520	14.38	23,471
1989	1,194,993.34	854,659	823,814	371,179	14.83	25,029
1990	1,049,092.83	737,722	711,097	337,996	15.30	22,091

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1991	1,621,648.89	1,120,397	1,079,961	541,688	15.77	34,349
1992	1,187,831.31	805,587	776,513	411,318	16.25	25,312
1993	2,104,478.36	1,399,478	1,348,970	755,508	16.75	45,105
1994	2,415,395.28	1,573,388	1,516,604	898,792	17.26	52,074
1995	2,328,706.78	1,484,551	1,430,973	897,734	17.77	50,520
1996	2,377,366.51	1,481,575	1,428,104	949,262	18.29	51,901
1997	2,699,470.41	1,642,358	1,583,085	1,116,386	18.83	59,288
1998	2,404,381.85	1,426,279	1,374,804	1,029,578	19.37	53,153
1999	2,127,064.22	1,228,805	1,184,457	942,607	19.92	47,320
2000	2,211,709.32	1,242,538	1,197,694	1,014,015	20.48	49,512
2001	1,791,536.81	981,583	946,157	845,380	20.83	40,585
2002	2,280,673.49	1,211,266	1,167,551	1,113,123	21.41	51,991
2003	2,620,540.94	1,346,434	1,297,841	1,322,700	22.00	60,123
2004	2,192,777.11	1,088,056	1,048,788	1,143,990	22.59	50,641
2005	2,295,409.64	1,097,435	1,057,828	1,237,582	23.20	53,344
2006	2,255,312.34	1,041,278	1,003,698	1,251,615	23.61	53,012
2007	2,467,867.17	1,092,772	1,053,333	1,414,534	24.23	58,379
2008	3,599,565.18	1,544,933	1,489,176	2,110,390	24.60	85,788
2009	3,032,531.49	1,241,822	1,197,004	1,835,527	25.24	72,723
2010	3,298,531.09	1,284,448	1,238,092	2,060,439	25.87	79,646
2011	5,882,276.75	2,178,795	2,100,161	3,782,116	26.34	143,588
2012	5,323,278.78	1,859,954	1,792,827	3,530,451	27.00	130,757
2013	6,936,123.91	2,284,759	2,202,301	4,733,823	27.48	172,264
2014	6,749,707.44	2,084,310	2,009,086	4,740,621	27.98	169,429
2015	6,408,782.63	1,842,525	1,776,027	4,632,755	28.50	162,553
2016	4,801,957.52	1,275,400	1,229,370	3,572,587	29.03	123,065
2017	5,127,709.42	1,247,059	1,202,052	3,925,657	29.56	132,803
2018	1,315,892.78	290,812	280,316	1,035,576	29.96	34,565
2019	5,711,652.16	1,126,338	1,085,688	4,625,964	30.52	151,572
2020	4,737,034.99	822,349	792,670	3,944,365	30.95	127,443
2021	8,660,112.63	1,295,553	1,248,796	7,411,317	31.26	237,086
2022	6,414,698.93	799,271	770,425	5,644,274	31.60	178,616
2023	6,591,094.72	652,518	628,968	5,962,126	31.84	187,253

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2024	13,445,042.93	981,488	946,066	12,498,977	31.75	393,669
2025	6,704,600.81	305,730	294,696	6,409,905	31.39	204,202
2026	17,877,453.40	296,766	286,056	17,591,398	29.62	593,903
	167,743,995.21	50,425,339	48,605,464	119,138,531		4,384,327
	1,799,933,111.20	511,798,093	485,016,289	1,314,916,822		47,737,596
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.5	2.65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1948	278.30	278	278			
1949	1,637.57	1,638	1,638			
1950	1,998.10	1,998	1,998			
1951	2,802.79	2,803	2,803			
1952	4,439.21	4,439	4,439			
1953	3,739.76	3,740	3,740			
1954	1,449.23	1,449	1,449			
1955	2,733.44	2,733	2,733			
1956	3,116.37	3,116	3,116			
1957	2,565.73	2,566	2,566			
1958	3,875.03	3,875	3,875			
1959	3,982.72	3,983	3,983			
1960	4,763.84	4,739	4,764			
1961	6,079.97	6,009	6,080			
1962	7,412.48	7,275	7,412			
1963	7,691.52	7,493	7,692			
1964	9,303.55	8,993	9,304			
1965	8,908.29	8,545	8,908			
1966	8,739.43	8,315	8,739			
1967	22,943.62	21,650	22,944			
1968	51,123.16	47,843	51,123			
1969	49,984.05	46,374	49,984			
1970	43,921.85	40,396	43,922			
1971	18,909.69	17,239	18,910			
1972	18,444.82	16,667	18,445			
1973	37,329.23	33,431	37,286	43	3.76	11
1974	41,407.42	36,749	40,987	421	4.05	104
1975	34,579.75	30,401	33,907	673	4.35	155
1976	23,366.13	20,354	22,701	665	4.64	143
1977	31,095.76	26,820	29,913	1,183	4.95	239
1978	77,730.03	66,395	74,051	3,679	5.25	701
1979	94,954.08	80,263	89,518	5,436	5.57	976
1980	403,317.77	337,331	376,229	27,089	5.89	4,599
1981	236,159.62	195,290	217,809	18,351	6.23	2,946
1982	146,167.32	128,072	142,840	3,327	6.25	532
1983	16,299.16	14,169	15,803	496	6.50	76
1984	83,178.51	71,692	79,959	3,220	6.77	476
1985	289,796.93	247,458	275,992	13,804	7.06	1,955
1986	185,422.00	156,719	174,790	10,632	7.37	1,443
1987	291,681.24	242,708	270,695	20,986	7.92	2,650
1988	273,301.44	224,763	250,681	22,621	8.26	2,739

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1989	357,325.21	290,148	323,605	33,720	8.62	3,912
1990	701,197.35	561,729	626,502	74,695	9.00	8,299
1991	754,735.74	595,939	664,657	90,079	9.39	9,593
1992	726,241.06	564,652	629,762	96,479	9.80	9,845
1993	607,973.52	464,978	518,595	89,379	10.23	8,737
1994	844,890.71	634,851	708,056	136,835	10.67	12,824
1995	1,050,925.89	775,058	864,430	186,496	11.12	16,771
1996	748,098.95	540,876	603,245	144,854	11.59	12,498
1997	963,822.72	682,194	760,858	202,965	12.07	16,816
1998	883,470.00	611,450	681,957	201,513	12.57	16,031
1999	1,149,160.47	776,603	866,153	283,007	13.07	21,653
2000	1,206,536.32	794,987	886,657	319,879	13.59	23,538
2001	1,587,327.32	1,018,112	1,135,511	451,816	14.12	31,998
2002	1,333,755.56	834,397	930,612	403,144	14.51	27,784
2003	1,070,547.29	649,608	724,515	346,033	15.07	22,962
2004	1,009,768.11	593,138	661,533	348,235	15.63	22,280
2005	1,132,456.60	642,556	716,649	415,807	16.20	25,667
2006	6,261,324.33	3,436,215	3,832,447	2,428,878	16.65	145,879
2007	716,328.36	377,792	421,355	294,973	17.25	17,100
2008	2,603,051.37	1,329,118	1,482,379	1,120,672	17.73	63,208
2009	1,070,696.73	524,641	585,138	485,559	18.21	26,664
2010	806,977.28	376,858	420,314	386,664	18.83	20,534
2011	1,575,613.37	700,833	781,646	793,967	19.34	41,053
2012	1,299,590.29	548,427	611,666	687,924	19.86	34,639
2013	2,104,370.10	835,224	931,534	1,172,836	20.51	57,184
2014	2,706,986.25	1,008,352	1,124,626	1,582,361	21.06	75,136
2015	1,814,408.35	630,144	702,806	1,111,602	21.61	51,439
2016	2,649,598.49	851,316	949,482	1,700,117	22.18	76,651
2017	2,988,075.62	882,678	984,460	2,003,616	22.66	88,421
2018	6,487,580.70	1,742,564	1,943,500	4,544,081	23.15	196,289
2019	2,173,964.52	523,491	583,855	1,590,110	23.65	67,235
2020	2,336,675.44	495,142	552,237	1,784,438	24.17	73,829
2021	2,630,309.66	480,295	535,678	2,094,632	24.62	85,078
2022	5,345,561.82	815,733	909,796	4,435,766	25.00	177,431
2023	3,754,650.11	455,815	508,375	3,246,275	25.32	128,210
2024	4,635,565.08	414,883	462,723	4,172,842	25.43	164,091
2025	6,597,503.51	369,460	412,063	6,185,441	25.31	244,387
2026	4,388,506.76	89,526	99,849	4,288,657	23.95	179,067
	83,632,201.87	30,106,554	33,563,230	50,068,972		2,324,478

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1955	775.81	776	776			
1956	3,271.04	3,271	3,271			
1957	1,205.53	1,206	1,206			
1958	5,574.37	5,574	5,574			
1959	2,685.00	2,685	2,685			
1960	8,231.61	8,188	8,232			
1961	25,855.74	25,554	25,856			
1962	45,408.73	44,564	45,409			
1963	53,242.91	51,868	53,243			
1964	117,863.76	113,935	117,864			
1965	218,303.72	209,390	218,304			
1966	323,327.46	307,611	323,327			
1967	255,215.52	240,824	255,216			
1968	301,020.66	281,704	301,021			
1969	453,738.19	420,969	453,738			
1970	389,883.40	358,584	389,883			
1971	253,727.22	231,315	253,727			
1972	251,889.27	227,610	251,889			
1973	111,863.83	100,181	111,864			
1974	34,789.97	30,876	34,790			
1975	57,445.76	50,505	56,941	505	4.35	116
1976	24,917.23	21,706	24,472	445	4.64	96
1977	41,421.69	35,726	40,279	1,143	4.95	231
1978	36,585.59	31,250	35,232	1,353	5.25	258
1979	112,853.67	95,393	107,550	5,304	5.57	952
1980	857,333.15	717,065	808,446	48,888	5.89	8,300
1981	1,230,604.82	1,017,636	1,147,320	83,284	6.23	13,368
1982	79,640.68	69,781	78,674	967	6.25	155
1983	47,039.85	40,892	46,103	937	6.50	144
1984	236,679.20	203,994	229,990	6,689	6.77	988
1985	468,140.67	399,745	450,687	17,453	7.06	2,472
1986	572,814.07	484,142	545,840	26,974	7.37	3,660
1987	512,368.65	426,342	480,674	31,695	7.92	4,002
1988	626,579.68	515,299	580,967	45,613	8.26	5,522
1989	588,981.43	478,253	539,200	49,781	8.62	5,775
1990	589,404.00	472,172	532,344	57,060	9.00	6,340
1991	697,528.88	550,769	620,957	76,572	9.39	8,155
1992	1,062,742.39	826,282	931,581	131,162	9.80	13,384
1993	1,261,818.43	965,039	1,088,021	173,798	10.23	16,989
1994	2,268,826.43	1,704,796	1,922,050	346,776	10.67	32,500
1995	370,245.05	273,056	307,853	62,392	11.12	5,611

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1996	1,138,913.44	823,434	928,370	210,544	11.59	18,166
1997	1,068,094.37	755,997	852,339	215,755	12.07	17,875
1998	1,478,304.29	1,023,134	1,153,519	324,785	12.57	25,838
1999	737,936.72	498,698	562,251	175,686	13.07	13,442
2000	791,073.99	521,239	587,664	203,410	13.59	14,968
2001	930,929.30	597,098	673,190	257,739	14.12	18,253
2002	949,814.03	594,204	669,928	279,886	14.51	19,289
2003	582,095.73	353,216	398,229	183,867	15.07	12,201
2004	1,774,028.38	1,042,064	1,174,861	599,167	15.63	38,334
2005	1,218,271.69	691,247	779,337	438,934	16.20	27,095
2006	1,269,145.65	696,507	785,268	483,878	16.65	29,062
2007	952,382.72	502,287	566,297	386,086	17.25	22,382
2008	515,081.18	263,000	296,516	218,565	17.73	12,327
2009	734,290.03	359,802	405,654	328,636	18.21	18,047
2010	386,324.81	180,414	203,405	182,919	18.83	9,714
2011	1,182,156.44	525,823	592,832	589,324	19.34	30,472
2012	518,255.62	218,704	246,575	271,681	19.86	13,680
2013	655,895.75	260,325	293,500	362,396	20.51	17,669
2014	1,003,907.24	373,955	421,611	582,297	21.06	27,649
2015	1,061,983.85	368,827	415,829	646,155	21.61	29,901
2016	943,458.20	303,133	341,763	601,695	22.18	27,128
2017	914,111.20	270,028	304,440	609,672	22.66	26,905
2018	3,347,616.93	899,170	1,013,757	2,333,859	23.15	100,815
2019	673,281.54	162,126	182,787	490,495	23.65	20,740
2020	1,801,120.23	381,657	430,294	1,370,826	24.17	56,716
2021	1,187,173.30	216,778	244,404	942,770	24.62	38,293
2022	3,548,501.24	541,501	610,508	2,937,993	25.00	117,520
2023	2,703,617.44	328,219	370,046	2,333,571	25.32	92,163
2024	2,551,686.49	228,376	257,480	2,294,207	25.43	90,217
2025	5,195,692.48	290,959	328,038	4,867,655	25.31	192,321
2026	5,967,348.34	121,734	137,247	5,830,101	23.95	243,428
	62,384,337.68	26,440,184	29,660,995	32,723,343		1,551,628
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1966	16,556.84	15,752	14,369	2,188	1.75	1,250
1967	23,712.61	22,375	20,410	3,302	2.03	1,627
1968	41,343.79	38,691	35,293	6,050	2.31	2,619

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1969	27,869.04	25,856	23,585	4,284	2.60	1,648
1970	26,296.73	24,186	22,062	4,235	2.89	1,465
1971	65,302.00	59,534	54,306	10,996	3.18	3,458
1972	90,224.32	81,528	74,369	15,856	3.47	4,569
1973	48,674.77	43,591	39,763	8,912	3.76	2,370
1974	51,686.57	45,872	41,844	9,843	4.05	2,430
1975	33,514.45	29,465	26,878	6,637	4.35	1,526
1976	13,638.29	11,880	10,837	2,802	4.64	604
1977	8,024.64	6,921	6,313	1,711	4.95	346
1978	20,233.89	17,283	15,765	4,469	5.25	851
1979	82,217.01	69,496	63,393	18,824	5.57	3,380
1980	35,257.75	29,489	26,899	8,358	5.89	1,419
1981	74,655.56	61,736	56,315	18,341	6.23	2,944
1982	65,297.22	57,213	52,189	13,108	6.25	2,097
1983	51,113.58	44,433	40,531	10,582	6.50	1,628
1984	67,115.22	57,847	52,767	14,348	6.77	2,119
1985	88,458.81	75,535	68,902	19,557	7.06	2,770
1986	61,903.59	52,321	47,726	14,177	7.37	1,924
1987	10,880.03	9,053	8,258	2,622	7.92	331
1988	24,115.88	19,833	18,091	6,024	8.26	729
1989	152,844.75	124,110	113,211	39,633	8.62	4,598
1990	178,467.28	142,970	130,415	48,052	9.00	5,339
1991	153,366.57	121,098	110,464	42,903	9.39	4,569
1992	73,625.00	57,243	52,216	21,409	9.80	2,185
1993	63,391.72	48,482	44,225	19,167	10.23	1,874
1995	23,870.99	17,605	16,059	7,812	11.12	703
1996	16,217.76	11,725	10,695	5,522	11.59	476
2000	4,157.02	2,739	2,498	1,659	13.59	122
2001	3,650.45	2,341	2,135	1,515	14.12	107
2002	14,474.51	9,055	8,260	6,215	14.51	428
2003	101,296.17	61,467	56,069	45,227	15.07	3,001
2004	44,912.16	26,381	24,064	20,848	15.63	1,334
2006	128,924.74	70,754	64,541	64,384	16.65	3,867
2008	82,533.52	42,142	38,441	44,092	17.73	2,487
2011	31,395.48	13,965	12,739	18,657	19.34	965
2012	741,450.15	312,892	285,416	456,034	19.86	22,962
2013	1,254,670.45	497,979	454,250	800,421	20.51	39,026
2014	612,660.37	228,216	208,175	404,485	21.06	19,206
2015	881,785.59	306,244	279,352	602,434	21.61	27,878
2016	425,095.44	136,583	124,589	300,506	22.18	13,549
2017	803,126.17	237,243	216,410	586,716	22.66	25,892

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
2018	973,306.51	261,430	238,473	734,834	23.15	31,742
2019	876,093.76	210,963	192,438	683,656	23.65	28,907
2020	835,716.50	177,088	161,537	674,179	24.17	27,893
2021	961,735.97	175,613	160,192	801,544	24.62	32,557
2022	1,206,631.42	184,132	167,963	1,038,669	25.00	41,547
2023	1,449,796.15	176,005	160,549	1,289,247	25.32	50,918
2024	900,867.78	80,628	73,548	827,320	25.43	32,533
2025	779,913.33	43,675	39,840	740,074	25.31	29,240
	14,804,070.30	4,680,658	4,269,631	10,534,439		500,009
	160,820,609.85	61,227,396	67,493,856	93,326,754		4,376,115
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.3	2.72

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	2,442,097.74	2,038,907	1,380,280	1,061,817	3.26	325,711
2012	2,499,940.96	1,957,454	1,325,139	1,174,802	4.02	292,239
2013	1,258,409.95	944,563	639,441	618,968	4.49	137,855
2014	83,379.92	59,517	40,291	43,089	5.01	8,601
2015	1,085,289.14	730,183	494,313	590,977	5.59	105,720
2016	689,401.82	432,875	293,044	396,358	6.22	63,723
2017	1,091,981.31	630,728	426,984	664,997	6.95	95,683
2018	1,120,450.47	587,564	397,764	722,687	7.71	93,734
2019	2,497,059.79	1,166,626	789,772	1,707,288	8.55	199,683
2020	2,698,669.67	1,099,978	744,653	1,954,017	9.45	206,774
2021	2,390,202.39	827,010	559,862	1,830,341	10.40	175,994
2022	1,549,700.85	439,340	297,420	1,252,281	11.37	110,139
2023	1,782,610.00	393,600	266,456	1,516,154	12.35	122,766
2024	1,288,295.59	203,293	137,623	1,150,672	13.35	86,193
2025	387,546.05	36,662	24,819	362,727	14.35	25,277
2026	2,196,078.03	69,396	46,979	2,149,099	15.35	140,006
	25,061,113.68	11,617,696	7,864,840	17,196,274		2,190,098
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	28,486.24	27,711	28,486			
2000	77,483.04	74,849	77,374	109	0.92	109
2001	448,549.67	430,383	444,900	3,649	1.07	3,410
2002	1,381,276.02	1,313,041	1,357,332	23,944	1.26	19,003
2003	587,775.10	552,097	570,720	17,055	1.50	11,370
2004	2,333,320.32	2,169,988	2,243,185	90,136	1.67	53,974
2005	991,205.31	909,926	940,619	50,586	1.90	26,624
2006	1,066,120.31	965,052	997,605	68,516	2.12	32,319
2007	1,255,274.68	1,116,441	1,154,100	101,175	2.39	42,333
2008	412,679.37	361,879	374,086	38,594	2.60	14,844
2009	45,796.30	39,270	40,595	5,202	2.91	1,788
2010	218,341.10	182,293	188,442	29,899	3.26	9,171
2011	174,667.62	141,586	146,362	28,306	3.62	7,819
2012	95,415.93	74,711	77,231	18,185	4.02	4,524
2013	68,062.17	51,087	52,810	15,252	4.49	3,397
2014	165,997.59	118,489	122,486	43,512	5.01	8,685
2016	192,946.28	121,151	125,238	67,709	6.22	10,886
2017	978,946.82	565,440	584,513	394,434	6.95	56,753

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2018	334,788.05	175,563	181,485	153,303	7.71	19,884
2019	40,588.03	18,963	19,603	20,985	8.55	2,454
2020	312,397.92	127,333	131,628	180,770	9.45	19,129
2021	547,323.29	189,374	195,762	351,561	10.40	33,804
2022	892,779.16	253,103	261,641	631,139	11.37	55,509
2023	1,677,935.34	370,488	382,985	1,294,950	12.35	104,854
2024	1,555,326.40	245,431	253,710	1,301,617	13.35	97,499
2025	598,190.74	56,589	58,498	539,693	14.35	37,609
2026	2,986,153.55	94,362	97,545	2,888,609	15.35	188,183
	19,467,826.35	10,746,600	11,108,938	8,358,888		865,934
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1986	6,845.85	6,846	6,846			
1988	2,865.11	2,865	2,865			
1989	1,391.92	1,392	1,392			
1991	2,630.18	2,630	2,630			
1992	212.29	212	212			
1993	424.58	425	425			
2009	396,383.10	339,899	355,048	41,335	2.91	14,204
2020	5,164.22	2,105	2,199	2,965	9.45	314
2021	5,127.99	1,774	1,853	3,275	10.40	315
	421,045.24	358,148	373,470	47,575		14,833
	44,949,985.27	22,722,444	19,347,248	25,602,737		3,070,865
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.3	6.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	95,131.21	77,712	85,703	9,428	8.24	1,144
1972	87,987.42	71,192	78,513	9,475	8.59	1,103
1973	120,104.97	96,191	106,082	14,023	8.96	1,565
1974	128,019.59	101,448	111,880	16,140	9.34	1,728
1975	88,353.43	69,250	76,371	11,982	9.73	1,231
1976	46,114.03	35,733	39,407	6,707	10.13	662
1977	79,876.69	61,150	67,438	12,439	10.55	1,179
1978	93,593.70	70,777	78,055	15,539	10.97	1,416
1979	294,569.47	219,878	242,488	52,081	11.41	4,565
1980	557,534.23	410,591	452,812	104,722	11.86	8,830
1981	630,621.55	457,831	504,910	125,712	12.33	10,196
1982	507,316.34	401,845	443,167	64,149	11.61	5,525
1983	527,807.31	413,168	455,654	72,153	12.00	6,013
1984	462,722.57	357,777	394,567	68,155	12.39	5,501
1985	650,584.10	496,461	547,512	103,072	12.81	8,046
1986	666,591.27	501,743	553,337	113,254	13.22	8,567
1987	747,052.62	551,250	607,935	139,117	13.94	9,980
1988	963,639.06	700,373	772,393	191,246	14.38	13,299
1989	1,047,413.25	749,110	826,141	221,272	14.83	14,921
1990	1,307,989.34	919,778	1,014,359	293,630	15.30	19,192
1991	1,303,227.85	900,400	992,989	310,239	15.77	19,673
1992	1,222,992.24	829,433	914,724	308,268	16.25	18,970
1993	950,967.30	632,393	697,422	253,545	16.75	15,137
1994	1,350,463.52	879,692	970,151	380,312	17.26	22,034
1995	1,494,019.98	952,438	1,050,378	443,642	17.77	24,966
1996	1,391,570.56	867,227	956,404	435,166	18.29	23,793
1997	1,639,669.13	997,575	1,100,156	539,513	18.83	28,652
1998	1,813,597.20	1,075,826	1,186,454	627,143	19.37	32,377
1999	1,781,221.77	1,029,012	1,134,826	646,396	19.92	32,450
2000	1,815,454.49	1,019,922	1,124,801	690,653	20.48	33,723
2001	1,762,449.82	965,646	1,064,944	697,506	20.83	33,486
2002	1,019,578.23	541,498	597,181	422,398	21.41	19,729
2003	1,418,225.38	728,684	803,615	614,610	22.00	27,937
2004	1,114,058.20	552,796	609,640	504,418	22.59	22,329
2005	1,287,659.47	615,630	678,936	608,724	23.20	26,238
2006	1,351,744.11	624,100	688,277	663,468	23.61	28,101
2007	7,141,224.56	3,162,134	3,487,298	3,653,927	24.23	150,802
2008	3,005,058.36	1,289,771	1,422,399	1,582,660	24.60	64,336
2009	2,204,014.65	902,544	995,353	1,208,662	25.24	47,887
2011	1,790,873.23	663,339	731,550	1,059,323	26.34	40,217
2012	2,209,936.33	772,152	851,553	1,358,384	27.00	50,311

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	2,724,218.62	897,358	989,634	1,734,585	27.48	63,122
2014	2,021,997.05	624,393	688,600	1,333,397	27.98	47,655
2015	2,696,806.52	775,332	855,060	1,841,747	28.50	64,623
2016	2,878,854.43	764,624	843,251	2,035,604	29.03	70,121
2017	2,901,883.21	705,738	778,309	2,123,574	29.56	71,839
2018	3,933,645.63	869,336	958,730	2,974,915	29.96	99,296
2019	2,979,971.71	587,650	648,078	2,331,893	30.52	76,405
2020	1,908,482.27	331,313	365,382	1,543,100	30.95	49,858
2021	4,715,653.55	705,462	778,005	3,937,649	31.26	125,964
2022	5,645,537.44	703,434	775,768	4,869,769	31.60	154,107
2023	9,079,272.28	898,848	991,277	8,087,995	31.84	254,020
2024	5,574,067.73	406,907	448,749	5,125,318	31.75	161,427
2025	4,054,400.17	184,881	203,892	3,850,508	31.39	122,667
2026	5,855,115.52	97,195	107,190	5,747,926	29.62	194,056
	105,140,934.66	35,317,941	38,949,702	66,191,233		2,442,971
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1977	203.20	156	183	20	10.55	2
1978	411.20	311	365	46	10.97	4
1979	958.15	715	839	119	11.41	10
1980	1,782.81	1,313	1,541	242	11.86	20
1981	1,056.40	767	900	156	12.33	13
1982	13,798.46	10,930	12,825	973	11.61	84
1983	212.09	166	195	17	12.00	1
1984	8,513.78	6,583	7,724	789	12.39	64
1985	147.05	112	131	16	12.81	1
1986	1,429.93	1,076	1,263	167	13.22	13
1987	1,752.16	1,293	1,517	235	13.94	17
2000	4,313.02	2,423	2,843	1,470	20.48	72
2001	1,685.98	924	1,084	602	20.83	29
2006	1,114.00	514	603	511	23.61	22
2007	1,136,336.86	503,170	590,420	545,917	24.23	22,531
2008	939,364.72	403,175	473,085	466,279	24.60	18,954
2009	650,372.98	266,328	312,509	337,864	25.24	13,386
2010	631,510.63	245,910	288,551	342,960	25.87	13,257
2011	777,699.22	288,060	338,010	439,690	26.34	16,693
2012	846,480.92	295,760	347,045	499,436	27.00	18,498

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	631,712.75	208,086	244,168	387,545	27.48	14,103
2014	470,931.14	145,424	170,640	300,291	27.98	10,732
2015	391,695.93	112,613	132,140	259,556	28.50	9,107
2016	523,048.03	138,922	163,011	360,037	29.03	12,402
2017	1,022,735.99	248,729	291,859	730,877	29.56	24,725
2018	663,270.02	146,583	172,000	491,270	29.96	16,398
2019	1,194,682.00	235,591	276,442	918,240	30.52	30,087
2020	703,472.09	122,123	143,299	560,173	30.95	18,099
2021	910,882.36	136,268	159,897	750,986	31.26	24,024
2022	2,566,572.37	319,795	375,247	2,191,325	31.60	69,346
2023	4,016,474.39	397,631	466,580	3,549,894	31.84	111,492
2024	2,208,127.70	161,193	189,144	2,018,984	31.75	63,590
2025	654,919.93	29,864	35,042	619,878	31.39	19,748
	20,977,668.26	4,432,508	5,201,104	15,776,564		527,524
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	20,200.60	16,502	13,864	6,336	8.24	769
1972	10,310.18	8,342	7,009	3,302	8.59	384
1973	79,110.21	63,359	53,231	25,879	8.96	2,888
1974	19,522.74	15,471	12,998	6,525	9.34	699
1975	7,570.88	5,934	4,985	2,585	9.73	266
1976	1,419.97	1,100	924	496	10.13	49
1977	8.32	6	5	3	10.55	
1978	941.95	712	598	344	10.97	31
1979	10,243.39	7,646	6,424	3,820	11.41	335
1980	35,449.21	26,106	21,933	13,516	11.86	1,140
1981	32,661.12	23,712	19,922	12,739	12.33	1,033
1982	30,020.50	23,779	19,978	10,043	11.61	865
1983	30,902.85	24,191	20,324	10,579	12.00	882
1984	53,169.05	41,110	34,539	18,630	12.39	1,504
1985	58,242.45	44,445	37,341	20,902	12.81	1,632
1986	73,871.96	55,603	46,715	27,157	13.22	2,054
1987	56,576.18	41,748	35,075	21,502	13.94	1,542
1988	78,831.69	57,295	48,136	30,695	14.38	2,135
1989	82,939.85	59,319	49,837	33,103	14.83	2,232
1990	85,485.59	60,113	50,504	34,982	15.30	2,286
1991	69,626.09	48,105	40,416	29,211	15.77	1,852

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1992	76,010.01	51,550	43,310	32,700	16.25	2,012
1993	102,208.88	67,969	57,104	45,105	16.75	2,693
1994	110,609.47	72,051	60,534	50,076	17.26	2,901
1995	205,605.31	131,073	110,121	95,484	17.77	5,373
1996	302,707.08	188,647	158,492	144,215	18.29	7,885
1997	538,185.31	327,432	275,093	263,093	18.83	13,972
1998	382,465.81	226,879	190,613	191,853	19.37	9,905
1999	385,520.96	222,715	187,114	198,407	19.92	9,960
2000	324,540.44	182,327	153,182	171,358	20.48	8,367
2001	279,640.15	153,215	128,724	150,916	20.83	7,245
2002	342,927.87	182,129	153,016	189,912	21.41	8,870
2003	398,690.26	204,847	172,103	226,588	22.00	10,299
2004	369,543.38	183,367	154,056	215,487	22.59	9,539
2005	411,309.82	196,647	165,213	246,096	23.20	10,608
2006	675,593.10	311,921	262,061	413,532	23.61	17,515
2007	477,500.36	211,437	177,639	299,861	24.23	12,376
2008	838,993.96	360,096	302,535	536,459	24.60	21,807
2009	329,156.76	134,790	113,244	215,913	25.24	8,554
2010	398,012.61	154,986	130,212	267,801	25.87	10,352
2011	790,749.03	292,893	246,075	544,674	26.34	20,679
2012	630,863.73	220,424	185,190	445,674	27.00	16,506
2013	753,992.47	248,365	208,664	545,328	27.48	19,845
2014	1,061,483.35	327,786	275,390	786,093	27.98	28,095
2015	2,019,052.80	580,478	487,690	1,531,363	28.50	53,732
2016	653,749.63	173,636	145,881	507,869	29.03	17,495
2017	709,702.95	172,600	145,010	564,693	29.56	19,103
2018	1,266,564.31	279,911	235,168	1,031,397	29.96	34,426
2019	556,753.78	109,792	92,242	464,512	30.52	15,220
2020	18,810.66	3,266	2,744	16,067	30.95	519
2021	1,151,982.54	172,337	144,789	1,007,193	31.26	32,220
2022	759,883.95	94,682	79,547	680,337	31.60	21,530
2023	668,199.47	66,152	55,578	612,622	31.84	19,241
2024	1,071,253.01	78,201	65,701	1,005,552	31.75	31,671
2025	876,232.08	39,956	33,569	842,663	31.39	26,845
2026	436,555.74	7,247	6,089	430,467	29.62	14,533
	21,212,155.82	7,056,402	5,928,449	15,283,707		576,471
	147,330,758.74	46,806,851	50,079,255	97,251,504		3,546,966

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.4 2.41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1944	77.95	77	41	37	0.34	37
1957	117.06	107	57	60	3.92	15
1962	2,151.47	1,894	1,004	1,148	5.38	213
1964	17,920.86	15,543	8,239	9,682	5.97	1,622
1965	20,920.63	18,001	9,542	11,379	6.28	1,812
1966	29,758.73	25,401	13,464	16,295	6.59	2,473
1967	33,875.31	28,681	15,203	18,673	6.90	2,706
1968	27,894.47	23,419	12,413	15,481	7.22	2,144
1969	29,312.36	24,394	12,930	16,382	7.55	2,170
1970	46,449.79	38,306	20,304	26,145	7.89	3,314
1971	42,432.58	34,663	18,373	24,059	8.24	2,920
1972	30,600.18	24,759	13,124	17,476	8.59	2,034
1973	21,528.93	17,242	9,139	12,390	8.96	1,383
1974	24,295.63	19,253	10,205	14,090	9.34	1,509
1975	33,447.98	26,216	13,896	19,552	9.73	2,009
1976	7,088.04	5,492	2,911	4,177	10.13	412
1977	17,783.83	13,615	7,217	10,567	10.55	1,002
1978	23,253.21	17,585	9,321	13,932	10.97	1,270
1979	84,123.28	62,793	33,284	50,839	11.41	4,456
1980	175,119.76	128,965	68,359	106,761	11.86	9,002
1981	85,224.43	61,873	32,796	52,428	12.33	4,252
1982	129,428.81	102,521	54,342	75,086	11.61	6,467
1983	63,138.87	49,425	26,198	36,941	12.00	3,078
1984	58,876.10	45,523	24,130	34,746	12.39	2,804
1985	123,384.92	94,155	49,908	73,477	12.81	5,736
1986	140,377.12	105,662	56,007	84,370	13.22	6,382
1987	136,832.49	100,969	53,520	83,313	13.94	5,977
1988	175,491.48	127,547	67,608	107,884	14.38	7,502
1989	213,503.89	152,698	80,939	132,565	14.83	8,939
1990	214,130.92	150,577	79,815	134,316	15.30	8,779
1991	78,271.51	54,078	28,665	49,607	15.77	3,146
1992	96,689.87	65,575	34,759	61,931	16.25	3,811
1993	33,962.96	22,585	11,971	21,992	16.75	1,313
1994	111,740.54	72,788	38,582	73,158	17.26	4,239
1995	158,945.89	101,328	53,710	105,236	17.77	5,922
1996	44,731.50	27,877	14,776	29,955	18.29	1,638
1997	90,392.75	54,995	29,151	61,242	18.83	3,252
1998	55,905.23	33,163	17,578	38,327	19.37	1,979
1999	104,475.10	60,355	31,992	72,483	19.92	3,639
2000	92,875.32	52,177	27,657	65,218	20.48	3,184
2001	170,338.61	93,329	49,470	120,869	20.83	5,803

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2002	54,814.24	29,112	15,431	39,383	21.41	1,839
2003	133,190.26	68,433	36,274	96,917	22.00	4,405
2004	229,781.29	114,017	60,436	169,345	22.59	7,496
2005	221,319.48	105,813	56,087	165,232	23.20	7,122
2006	179,516.35	82,883	43,933	135,583	23.61	5,743
2008	542,890.68	233,009	123,509	419,382	24.60	17,048
2009	435,453.99	178,318	94,519	340,935	25.24	13,508
2010	540,142.20	210,331	111,488	428,654	25.87	16,570
2012	185,684.69	64,878	34,389	151,295	27.00	5,604
2013	64,891.21	21,375	11,330	53,561	27.48	1,949
2020	80,753.41	14,019	7,431	73,322	30.95	2,369
2022	23,952.58	2,984	1,582	22,371	31.60	708
2023	58,165.17	5,758	3,052	55,113	31.84	1,731
2024	30,384.42	2,218	1,176	29,209	31.75	920
2025	60,929.95	2,778	1,473	59,457	31.39	1,894
	5,888,740.28	3,291,532	1,744,711	4,144,029		229,251
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1950	211.54	203	212			
1952	22,872.17	21,612	22,872			
1953	3,324.65	3,120	3,325			
1954	3,638.77	3,392	3,639			
1956	2,288.98	2,104	2,289			
1957	4,312.96	3,937	4,313			
1958	523.27	474	523			
1959	5,076.98	4,569	5,077			
1960	13,576.34	12,131	13,576			
1961	9,266.15	8,218	9,266			
1962	28,692.16	25,262	28,692			
1963	14,471.10	12,648	14,471			
1964	37,803.93	32,788	37,804			
1965	38,378.73	33,023	38,379			
1966	31,246.60	26,671	31,247			
1967	24,202.13	20,491	24,202			
1968	19,889.94	16,699	19,890			
1969	19,954.10	16,606	19,954			
1970	22,762.73	18,772	22,763			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	20,289.92	16,575	20,290			
1972	17,294.88	13,993	17,295			
1973	11,492.55	9,204	11,493			
1974	24,418.58	19,350	24,419			
1975	16,319.18	12,791	16,319			
1976	25,023.29	19,390	25,023			
1977	43,118.59	33,010	43,119			
1978	25,979.99	19,647	25,980			
1979	50,315.47	37,557	49,985	331	11.41	29
1980	157,640.32	116,093	154,508	3,132	11.86	264
1981	85,258.09	61,897	82,379	2,880	12.33	234
1984	251.00	194	251			
1985	76,948.28	58,719	76,948			
1986	6,297.30	4,740	6,297			
1987	4,517.67	3,334	4,441	77	13.94	6
1988	436.80	317	422	15	14.38	1
1989	61,414.76	43,924	58,507	2,908	14.83	196
1990	113,229.49	79,623	106,058	7,171	15.30	469
1991	3,009.98	2,080	2,771	239	15.77	15
1992	70,156.42	47,580	63,377	6,780	16.25	417
1993	67,108.70	44,627	59,443	7,665	16.75	458
1994	82,593.19	53,801	71,663	10,930	17.26	633
1995	26,780.69	17,073	22,741	4,039	17.77	227
1996	1,225.32	764	1,018	208	18.29	11
1997	216,693.86	131,837	175,607	41,087	18.83	2,182
1998	256,742.97	152,300	202,864	53,879	19.37	2,782
1999	8,429.94	4,870	6,487	1,943	19.92	98
2000	84,587.64	47,521	63,298	21,290	20.48	1,040
2001	118,361.21	64,850	86,380	31,981	20.83	1,535
2002	169,552.53	90,049	119,946	49,607	21.41	2,317
2003	148,288.73	76,191	101,487	46,802	22.00	2,127
2004	220,104.20	109,216	145,476	74,628	22.59	3,304
2007	122,142.22	54,085	72,041	50,101	24.23	2,068
2009	114,064.35	46,709	62,217	51,848	25.24	2,054
2010	62,519.49	24,345	32,428	30,092	25.87	1,163
2018	45.98	10	13	33	29.96	1
2022	6,986.91	871	1,160	5,827	31.60	184

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2023	18,231.73	1,805	2,404	15,827	31.84	497
2024	57,581.69	4,203	5,598	51,983	31.75	1,637
2025	18,398.87	839	1,118	17,281	31.39	551
	2,916,346.01	1,788,704	2,325,763	590,583		26,500
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1970	5,001.66	4,125	5,002			
1971	12,065.77	9,856	12,066			
1972	16,158.21	13,074	16,158			
1973	23,610.65	18,910	23,611			
1974	11,934.41	9,457	11,934			
1975	6,620.80	5,189	6,615	6	9.73	1
1976	3,884.68	3,010	3,837	47	10.13	5
1977	5,230.27	4,004	5,105	126	10.55	12
1978	5,706.05	4,315	5,501	205	10.97	19
1979	25,223.43	18,828	24,003	1,220	11.41	107
1980	21,935.83	16,154	20,594	1,342	11.86	113
1981	13,794.39	10,015	12,768	1,027	12.33	83
1982	18,523.58	14,673	18,524			
1983	29,007.23	22,707	28,954	53	12.00	4
1984	25,172.95	19,464	24,819	354	12.39	29
1985	27,049.72	20,642	26,321	729	12.81	57
1986	27,469.49	20,676	26,364	1,105	13.22	84
1987	27,188.25	20,062	25,581	1,607	13.94	115
1988	33,227.77	24,150	30,794	2,434	14.38	169
1989	49,270.86	35,239	44,934	4,337	14.83	292
1990	52,753.58	37,096	47,302	5,452	15.30	356
1991	51,222.02	35,389	45,125	6,097	15.77	387
1992	54,594.81	37,026	47,212	7,382	16.25	454
1993	58,410.15	38,843	49,529	8,881	16.75	530
1994	72,041.99	46,928	59,839	12,203	17.26	707
1995	66,567.19	42,437	54,112	12,455	17.77	701
1996	69,627.81	43,392	55,330	14,298	18.29	782
1997	42,597.30	25,916	33,046	9,551	18.83	507
1998	67,630.64	40,118	51,155	16,476	19.37	851
1999	15,985.66	9,235	11,776	4,210	19.92	211
2000	19,079.45	10,719	13,668	5,411	20.48	264

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	14,019.42	7,681	9,794	4,225	20.83	203
2002	20,738.40	11,014	14,044	6,694	21.41	313
2003	16,488.67	8,472	10,803	5,686	22.00	258
2004	16,273.80	8,075	10,297	5,977	22.59	265
2005	8,074.49	3,860	4,922	3,153	23.20	136
2006	19,031.70	8,787	11,204	7,827	23.61	332
2007	18,179.90	8,050	10,265	7,915	24.23	327
2008	21,615.63	9,277	11,829	9,786	24.60	398
2009	25,708.61	10,528	13,424	12,284	25.24	487
2010	17,915.17	6,976	8,895	9,020	25.87	349
2011	25,078.47	9,289	11,845	13,234	26.34	502
2012	43,118.70	15,066	19,211	23,908	27.00	885
2013	31,965.64	10,529	13,426	18,540	27.48	675
2014	28,084.77	8,673	11,059	17,026	27.98	609
2015	17,007.06	4,890	6,235	10,772	28.50	378
2016	34,471.28	9,156	11,675	22,796	29.03	785
2017	118,289.24	28,768	36,683	81,607	29.56	2,761
2018	11,207.60	2,477	3,158	8,049	29.96	269
2019	341.14	67	85	256	30.52	8
2021	2,474.84	370	472	2,003	31.26	64
2022	3,340.12	416	530	2,810	31.60	89
2023	4,497.06	445	567	3,930	31.84	123
2024	3,946.39	288	367	3,579	31.75	113
2025	8,582.07	391	499	8,083	31.39	258
	1,469,036.77	835,194	1,062,869	406,168		17,427
	10,274,123.06	5,915,430	5,133,343	5,140,780		273,178

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8 2.66

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	32,099.03	26,221	29,695	2,404	8.24	292
1972	38,136.64	30,857	34,945	3,192	8.59	372
1973	46,699.12	37,401	42,356	4,344	8.96	485
1974	41,287.45	32,718	37,052	4,235	9.34	453
1975	28,525.71	22,358	25,320	3,206	9.73	329
1976	20,710.12	16,048	18,174	2,536	10.13	250
1977	30,396.78	23,271	26,354	4,043	10.55	383
1978	40,769.14	30,830	34,914	5,855	10.97	534
1979	68,832.87	51,380	58,186	10,646	11.41	933
1980	131,408.86	96,775	109,595	21,814	11.86	1,839
1981	110,631.00	80,318	90,958	19,673	12.33	1,596
1982	190,335.00	150,764	170,736	19,599	11.61	1,688
1983	141,533.91	110,793	125,470	16,064	12.00	1,339
1984	96,589.58	74,683	84,576	12,013	12.39	970
1985	157,339.96	120,066	135,971	21,369	12.81	1,668
1986	142,951.52	107,600	121,854	21,097	13.22	1,596
1987	168,313.63	124,199	140,652	27,662	13.94	1,984
1988	176,855.08	128,538	145,566	31,289	14.38	2,176
1989	245,809.88	175,803	199,092	46,718	14.83	3,150
1990	200,239.89	140,809	159,462	40,778	15.30	2,665
1991	127,914.76	88,376	100,083	27,831	15.77	1,765
1992	194,224.55	131,723	149,173	45,052	16.25	2,772
1993	110,374.14	73,399	83,122	27,252	16.75	1,627
1994	159,243.25	103,731	117,472	41,771	17.26	2,420
1995	225,556.84	143,792	162,840	62,716	17.77	3,529
1996	146,163.86	91,089	103,156	43,008	18.29	2,351
1997	183,670.61	111,745	126,548	57,122	18.83	3,034
1998	242,997.43	144,146	163,241	79,756	19.37	4,118
1999	163,009.46	94,171	106,646	56,363	19.92	2,829
2000	129,708.02	72,870	82,523	47,185	20.48	2,304
2001	175,354.91	96,077	108,805	66,550	20.83	3,195
2002	178,137.48	94,609	107,142	70,995	21.41	3,316
2003	463,652.54	238,225	269,783	193,869	22.00	8,812
2004	582,927.65	289,249	327,567	255,361	22.59	11,304
2005	461,613.81	220,698	249,934	211,679	23.20	9,124
2006	271,218.43	125,222	141,810	129,408	23.61	5,481
2008	801,363.82	343,945	389,508	411,856	24.60	16,742
2009	189,343.07	77,536	87,807	101,536	25.24	4,023
2010	213,698.43	83,214	94,238	119,461	25.87	4,618
2011	310,820.65	115,128	130,379	180,441	26.34	6,850
2012	514,236.52	179,674	203,476	310,761	27.00	11,510

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	418,060.32	137,709	155,952	262,109	27.48	9,538
2014	466,917.86	144,184	163,284	303,633	27.98	10,852
2015	456,957.65	131,375	148,779	308,179	28.50	10,813
2016	686,364.70	182,298	206,447	479,917	29.03	16,532
2017	746,787.10	181,619	205,679	541,109	29.56	18,305
2018	883,633.27	195,283	221,153	662,481	29.96	22,112
2019	540,738.04	106,634	120,760	419,978	30.52	13,761
2020	181,428.19	31,496	35,668	145,760	30.95	4,710
2021	270,428.66	40,456	45,815	224,613	31.26	7,185
2022	38,388.69	4,783	5,417	32,972	31.60	1,043
2023	2,635.29	261	296	2,340	31.84	73
2024	3,310.00	242	274	3,036	31.75	96
2025	219,866.82	10,026	11,354	208,513	31.39	6,643
	12,870,211.99	5,666,417	6,417,061	6,453,151		258,089
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1972	13,313.98	10,772	13,314			
1973	38,836.17	31,104	38,836			
1974	144,406.45	114,433	144,406			
1975	99,258.76	77,797	99,259			
1976	162,178.02	125,670	160,548	1,630	10.13	161
1977	227,638.93	174,271	222,638	5,001	10.55	474
1978	126,268.54	95,487	121,988	4,280	10.97	390
1979	78,656.93	58,713	75,008	3,649	11.41	320
1980	57,030.55	42,000	53,657	3,374	11.86	284
1981	109,907.92	79,793	101,939	7,969	12.33	646
1985	24,654.43	18,814	24,036	619	12.81	48
1986	27,447.15	20,659	26,393	1,054	13.22	80
1988	68,000.86	49,423	63,140	4,861	14.38	338
1989	58,448.77	41,803	53,405	5,044	14.83	340
1990	51,140.66	35,962	45,943	5,198	15.30	340
1991	39,011.61	26,953	34,434	4,578	15.77	290
1992	35,854.73	24,317	31,066	4,789	16.25	295
1993	51,676.44	34,365	43,903	7,774	16.75	464
1994	71,235.62	46,403	59,282	11,954	17.26	693
1995	49,500.84	31,557	40,315	9,186	17.77	517
1996	45,909.70	28,611	36,552	9,358	18.29	512

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1997	34,534.58	21,011	26,842	7,692	18.83	408
1998	49,970.37	29,642	37,869	12,102	19.37	625
1999	46,832.83	27,055	34,564	12,269	19.92	616
2000	39,699.21	22,303	28,493	11,206	20.48	547
2001	45,124.99	24,724	31,586	13,539	20.83	650
2002	66,517.98	35,328	45,133	21,385	21.41	999
2003	78,667.19	40,419	51,637	27,030	22.00	1,229
2004	165,793.01	82,266	105,098	60,695	22.59	2,687
2005	119,365.27	57,069	72,908	46,457	23.20	2,002
2006	70,424.87	32,515	41,539	28,886	23.61	1,223
2007	97,997.49	43,393	55,436	42,561	24.23	1,757
2008	109,845.80	47,146	60,231	49,615	24.60	2,017
2009	119,208.92	48,816	62,364	56,845	25.24	2,252
2010	90,572.74	35,269	45,058	45,515	25.87	1,759
2011	78,430.71	29,051	37,114	41,317	26.34	1,569
2012	113,394.32	39,620	50,616	62,778	27.00	2,325
2013	103,879.46	34,218	43,715	60,165	27.48	2,189
2014	114,396.21	35,326	45,130	69,266	27.98	2,476
2015	12,301.93	3,537	4,519	7,783	28.50	273
2016	95,701.05	25,418	32,472	63,229	29.03	2,178
2017	88,931.16	21,628	27,631	61,301	29.56	2,074
2018	56,220.18	12,425	15,873	40,347	29.96	1,347
2019	45,274.31	8,928	11,406	33,868	30.52	1,110
2020	38,662.29	6,712	8,575	30,087	30.95	972
2024	14,048.80	1,026	1,311	12,738	31.75	401
	3,476,172.73	1,933,752	2,467,180	1,008,993		41,877
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	5,439.90	4,444	5,051	389	8.24	47
1972	14,933.80	12,083	13,732	1,202	8.59	140
1973	7,861.73	6,296	7,155	706	8.96	79
1974	9,613.04	7,618	8,658	955	9.34	102
1975	4,932.44	3,866	4,394	539	9.73	55
1976	4,347.30	3,369	3,829	518	10.13	51
1977	3,525.43	2,699	3,067	458	10.55	43
1978	2,829.16	2,139	2,431	398	10.97	36
1979	3,571.30	2,666	3,030	541	11.41	47

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1980	10,155.76	7,479	8,500	1,656	11.86	140
1981	8,768.97	6,366	7,235	1,534	12.33	124
1982	7,863.13	6,228	7,078	785	11.61	68
1983	27,433.37	21,475	24,406	3,027	12.00	252
1984	14,612.72	11,299	12,841	1,771	12.39	143
1985	17,814.51	13,594	15,450	2,365	12.81	185
1986	8,715.77	6,560	7,455	1,260	13.22	95
1987	6,897.76	5,090	5,785	1,113	13.94	80
1988	18,499.00	13,445	15,280	3,219	14.38	224
1989	17,820.76	12,745	14,485	3,336	14.83	225
1990	13,760.77	9,677	10,998	2,763	15.30	181
1991	16,073.60	11,105	12,621	3,453	15.77	219
1992	6,559.93	4,449	5,056	1,504	16.25	93
1993	29,217.11	19,429	22,081	7,136	16.75	426
1994	25,165.33	16,393	18,631	6,535	17.26	379
1995	58,774.81	37,469	42,583	16,191	17.77	911
1996	115,510.48	71,986	81,812	33,699	18.29	1,842
1997	68,827.66	41,875	47,591	21,237	18.83	1,128
1998	53,919.97	31,985	36,351	17,569	19.37	907
1999	48,940.91	28,273	32,132	16,809	19.92	844
2000	55,190.97	31,006	35,238	19,953	20.48	974
2001	36,718.99	20,118	22,864	13,855	20.83	665
2002	75,211.94	39,945	45,397	29,815	21.41	1,393
2003	104,709.50	53,800	61,144	43,566	22.00	1,980
2004	98,717.26	48,984	55,670	43,047	22.59	1,906
2005	53,701.30	25,675	29,180	24,522	23.20	1,057
2006	64,103.29	29,596	33,636	30,468	23.61	1,290
2007	57,266.33	25,358	28,819	28,447	24.23	1,174
2008	105,754.48	45,390	51,586	54,169	24.60	2,202
2009	77,881.91	31,893	36,246	41,636	25.24	1,650
2010	36,000.84	14,019	15,933	20,068	25.87	776
2011	9,612.23	3,560	4,046	5,566	26.34	211
2012	1,472.30	514	584	888	27.00	33
2013	2,742.40	903	1,026	1,716	27.48	62
2014	4,238.77	1,309	1,488	2,751	27.98	98
2015	13,257.55	3,812	4,332	8,925	28.50	313
2016	6,407.77	1,702	1,934	4,473	29.03	154
2017	3,451.34	839	954	2,498	29.56	85
2018	17,977.88	3,973	4,515	13,463	29.96	449

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2019	421.75	83	94	327	30.52	11
2020	197.26	34	39	159	30.95	5
2024	25,549.95	1,865	2,120	23,430	31.75	738
	1,482,972.43	806,480	916,562	566,410		26,292
	17,829,357.15	8,406,649	9,800,803	8,028,554		326,258
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					24.6	1.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	649	692			
1956	2,239.85	2,059	2,240			
1957	4,785.87	4,369	4,786			
1960	16,750.58	14,968	16,751			
1961	12,800.59	11,353	12,801			
1962	22,033.72	19,399	22,034			
1963	24,186.10	21,139	24,186			
1964	21,937.83	19,027	21,930	8	5.97	1
1965	14,345.92	12,344	14,227	119	6.28	19
1966	22,819.15	19,478	22,449	370	6.59	56
1967	33,625.63	28,470	32,813	812	6.90	118
1968	78,227.64	65,677	75,696	2,532	7.22	351
1969	79,698.42	66,327	76,445	3,253	7.55	431
1970	56,628.40	46,700	53,824	2,804	7.89	355
1971	50,484.00	41,240	47,531	2,953	8.24	358
1972	74,487.40	60,269	69,463	5,024	8.59	585
1973	5,856.45	4,690	5,405	451	8.96	50
1974	2,435.60	1,930	2,224	211	9.34	23
1975	3,447.78	2,702	3,114	334	9.73	34
1976	1,925.80	1,492	1,720	206	10.13	20
1979	129,595.68	96,735	111,492	18,104	11.41	1,587
1980	273,942.52	201,742	232,518	41,424	11.86	3,493
1981	280,781.60	203,847	234,944	45,837	12.33	3,718
1982	232,089.47	183,838	211,883	20,207	11.61	1,740
1983	89,210.82	69,834	80,487	8,724	12.00	727
1984	47,248.78	36,533	42,106	5,143	12.39	415
1985	101,055.89	77,116	88,880	12,176	12.81	951
1986	78,585.49	59,151	68,175	10,411	13.22	788
1987	157,570.97	116,272	134,009	23,561	13.94	1,690
1988	283,620.35	206,135	237,581	46,039	14.38	3,202
1989	183,420.00	131,182	151,194	32,226	14.83	2,173
1990	203,975.86	143,436	165,317	38,658	15.30	2,527
1991	221,578.38	153,089	176,443	45,135	15.77	2,862
1992	121,714.83	82,547	95,140	26,575	16.25	1,635
1993	67,829.07	45,106	51,987	15,842	16.75	946
1994	215,739.93	140,533	161,972	53,768	17.26	3,115
1995	283,678.95	180,845	208,433	75,246	17.77	4,234
1996	638,322.65	397,803	458,489	179,834	18.29	9,832
1997	114,991.22	69,961	80,634	34,358	18.83	1,825
1998	89,135.98	52,875	60,941	28,195	19.37	1,456
1999	211,901.85	122,416	141,091	70,811	19.92	3,555

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2000	61,111.51	34,332	39,569	21,542	20.48	1,052
2001	5,688.76	3,117	3,593	2,096	20.83	101
2002	124,248.21	65,988	76,055	48,194	21.41	2,251
2005	16,976.59	8,117	9,355	7,621	23.20	328
2007	36,240.36	16,047	18,495	17,745	24.23	732
2008	123,273.33	52,909	60,980	62,293	24.60	2,532
2012	13,100.09	4,577	5,275	7,825	27.00	290
2014	217,660.91	67,214	77,468	140,193	27.98	5,010
2015	137,276.88	39,467	45,488	91,789	28.50	3,221
2016	122,361.10	32,499	37,457	84,904	29.03	2,925
2017	542,789.02	132,006	152,144	390,645	29.56	13,215
2018	224,701.21	49,659	57,235	167,467	29.96	5,590
2019	656,174.48	129,398	149,138	507,037	30.52	16,613
2020	2,116,662.54	367,453	423,509	1,693,154	30.95	54,706
2021	1,046,978.33	156,628	180,522	866,456	31.26	27,718
2023	75,522.95	7,477	8,618	66,905	31.84	2,101
2024	130,066.51	9,495	10,943	119,123	31.75	3,752
2025	120,110.28	5,477	6,313	113,798	31.39	3,625
	10,326,341.61	4,397,138	5,066,202	5,260,140		200,634
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	802	860			
1956	7,054.30	6,485	7,054			
1957	11,192.51	10,218	11,193			
1958	5,050.93	4,578	5,051			
1959	689.61	621	690			
1960	32,725.24	29,242	32,725			
1961	10,605.59	9,406	10,606			
1962	22,867.17	20,133	22,867			
1963	60,787.04	53,128	60,787			
1964	79,108.77	68,613	79,109			
1965	131,939.84	113,526	131,940			
1966	124,040.09	105,876	124,040			
1967	208,085.37	176,180	208,085			
1968	233,579.88	196,104	233,580			
1969	194,219.76	161,634	192,641	1,578	7.55	209
1970	271,294.84	223,729	266,648	4,646	7.89	589

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	229,764.59	187,692	223,698	6,066	8.24	736
1972	257,964.38	208,722	248,763	9,202	8.59	1,071
1973	108,983.37	87,284	104,028	4,955	8.96	553
1974	90,753.81	71,917	85,713	5,040	9.34	540
1975	52,275.40	40,972	48,832	3,443	9.73	354
1976	53,093.99	41,142	49,035	4,059	10.13	401
1977	29,803.40	22,816	27,193	2,610	10.55	247
1978	50,738.04	38,369	45,730	5,008	10.97	457
1979	92,133.69	68,772	81,965	10,169	11.41	891
1980	489,117.73	360,206	429,307	59,811	11.86	5,043
1981	230,826.16	167,580	199,728	31,098	12.33	2,522
1982	80,975.76	64,141	76,446	4,530	11.61	390
1983	42,099.09	32,955	39,277	2,822	12.00	235
1984	46,511.61	35,963	42,862	3,650	12.39	295
1985	72,222.02	55,113	65,686	6,536	12.81	510
1986	43,855.97	33,010	39,343	4,513	13.22	341
1987	107,897.65	79,618	94,892	13,006	13.94	933
1988	160,625.82	116,743	139,139	21,487	14.38	1,494
1989	30,425.01	21,760	25,934	4,491	14.83	303
1990	108,749.56	76,473	91,143	17,606	15.30	1,151
1991	127,229.75	87,903	104,766	22,464	15.77	1,424
1992	44,347.42	30,076	35,846	8,502	16.25	523
1993	29,918.28	19,896	23,713	6,205	16.75	370
1994	29,674.28	19,330	23,038	6,636	17.26	384
1995	34,913.41	22,257	26,527	8,387	17.77	472
1996	43,150.00	26,891	32,050	11,100	18.29	607
1997	147,679.42	89,848	107,084	40,595	18.83	2,156
1998	59,434.64	35,257	42,021	17,414	19.37	899
1999	115,364.91	66,646	79,431	35,934	19.92	1,804
2000	88,357.27	49,639	59,162	29,196	20.48	1,426
2001	81,293.19	44,541	53,086	28,208	20.83	1,354
2002	24,753.36	13,147	15,669	9,084	21.41	424
2003	6,572.47	3,377	4,025	2,548	22.00	116
2004	11,469.43	5,691	6,783	4,687	22.59	207
2005	8,155.02	3,899	4,647	3,508	23.20	151
2006	8,567.60	3,956	4,715	3,853	23.61	163
2007	26,075.02	11,546	13,761	12,314	24.23	508
2008	31,803.84	13,650	16,269	15,535	24.60	632
2009	68,220.04	27,936	33,295	34,925	25.24	1,384
2010	60,218.85	23,449	27,947	32,271	25.87	1,247
2011	489,447.99	181,292	216,070	273,377	26.34	10,379

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2012	154,849.37	54,104	64,483	90,366	27.00	3,347
2013	5,908.18	1,946	2,319	3,589	27.48	131
2014	69,835.34	21,565	25,702	44,133	27.98	1,577
2015	3,012,389.09	866,062	1,032,205	1,980,184	28.50	69,480
2016	2,481,717.48	659,144	785,592	1,696,125	29.03	58,427
2017	56,121.74	13,649	16,267	39,854	29.56	1,348
2019	397,651.78	78,417	93,460	304,192	30.52	9,967
2024	862,634.10	62,972	75,052	787,582	31.75	24,806
	12,350,671.41	5,529,609	6,571,573	5,779,098		214,978
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1939	89.71	90	90			
1941	89.92	90	90			
1942	132.55	133	133			
1943	519.50	517	520			
1944	66.27	66	66			
1945	197.76	195	198			
1946	210.81	207	211			
1947	189.78	185	190			
1948	87.19	85	87			
1949	87.37	84	87			
1950	87.21	83	87			
1952	1,264.04	1,194	1,264			
1954	1,295.64	1,208	1,296			
1955	1,459.28	1,351	1,459			
1956	7,989.37	7,345	7,989			
1957	2,882.94	2,632	2,883			
1958	2,621.93	2,377	2,622			
1959	13,155.57	11,840	13,156			
1960	21,791.82	19,472	21,792			
1961	5,140.94	4,559	5,137	4	5.09	1
1962	11,133.48	9,802	11,045	88	5.38	16
1963	27,205.19	23,777	26,792	413	5.67	73
1964	25,433.77	22,059	24,856	577	5.97	97
1965	44,705.41	38,466	43,344	1,362	6.28	217
1966	40,138.50	34,261	38,606	1,533	6.59	233
1967	46,496.82	39,367	44,359	2,138	6.90	310

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1968	40,693.47	34,165	38,497	2,196	7.22	304
1969	46,340.00	38,565	43,455	2,885	7.55	382
1970	37,730.12	31,115	35,061	2,669	7.89	338
1971	16,335.99	13,345	15,037	1,299	8.24	158
1972	17,271.21	13,974	15,746	1,525	8.59	178
1973	15,490.55	12,406	13,979	1,511	8.96	169
1974	23,342.04	18,497	20,843	2,499	9.34	268
1975	7,674.66	6,015	6,778	897	9.73	92
1976	8,287.28	6,422	7,236	1,051	10.13	104
1977	4,679.42	3,582	4,036	643	10.55	61
1978	8,786.99	6,645	7,488	1,299	10.97	118
1979	17,149.23	12,801	14,424	2,725	11.41	239
1980	98,806.16	72,765	81,992	16,814	11.86	1,418
1981	107,258.23	77,869	87,744	19,515	12.33	1,583
1982	82,009.44	64,960	73,198	8,812	11.61	759
1983	56,025.01	43,856	49,417	6,608	12.00	551
1984	108,908.02	84,208	94,886	14,022	12.39	1,132
1985	78,855.62	60,175	67,806	11,050	12.81	863
1986	100,593.75	75,717	85,319	15,275	13.22	1,155
1987	88,986.35	65,663	73,990	14,997	13.94	1,076
1988	201,473.49	146,431	165,000	36,473	14.38	2,536
1989	181,657.08	129,921	146,396	35,261	14.83	2,378
1990	168,603.03	118,562	133,597	35,006	15.30	2,288
1991	258,892.35	178,869	201,552	57,341	15.77	3,636
1992	306,930.57	208,160	234,557	72,374	16.25	4,454
1993	257,835.27	171,460	193,203	64,632	16.75	3,859
1994	299,323.68	194,979	219,704	79,619	17.26	4,613
1995	383,451.45	244,450	275,449	108,003	17.77	6,078
1996	263,499.16	164,213	185,037	78,462	18.29	4,290
1997	601,818.66	366,146	412,577	189,241	18.83	10,050
1998	655,734.79	388,982	438,309	217,426	19.37	11,225
1999	630,900.60	364,471	410,690	220,211	19.92	11,055
2000	507,768.74	285,264	321,439	186,330	20.48	9,098
2001	180,278.54	98,775	111,301	68,978	20.83	3,311
2002	500,252.10	265,684	299,376	200,877	21.41	9,382
2003	1,055,174.76	542,149	610,899	444,275	22.00	20,194
2004	899,852.63	446,507	503,129	396,724	22.59	17,562
2005	519,280.28	248,268	279,751	239,529	23.20	10,325
2006	908,500.49	419,455	472,646	435,854	23.61	18,461
2007	468,154.94	207,299	233,587	234,568	24.23	9,681
2008	725,718.64	311,478	350,977	374,742	24.60	15,233

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2009	490,438.50	200,835	226,303	264,135	25.24	10,465
2010	547,500.39	213,197	240,233	307,268	25.87	11,877
2011	967,264.36	358,275	403,708	563,556	26.34	21,395
2012	441,967.50	154,423	174,005	267,962	27.00	9,925
2013	339,653.10	111,882	126,070	213,583	27.48	7,772
2014	367,934.98	113,618	128,026	239,909	27.98	8,574
2015	393,017.07	112,992	127,321	265,696	28.50	9,323
2016	377,003.66	100,132	112,830	264,174	29.03	9,100
2017	892,787.90	217,126	244,660	648,128	29.56	21,926
2018	1,059,623.00	234,177	263,873	795,750	29.96	26,560
2019	554,539.13	109,355	123,222	431,317	30.52	14,132
2020	67,630.42	11,741	13,230	54,401	30.95	1,758
2021	1,282.89	192	216	1,067	31.26	34
2022	9,404.82	1,172	1,321	8,084	31.60	256
2023	741.88	73	82	660	31.84	21
2024	58,234.84	4,251	4,790	53,445	31.75	1,683
2025	801.75	37	42	760	31.39	24
2026	1,001,849.76	16,631	18,740	983,110	29.62	33,191
	18,766,473.51	8,425,822	9,493,138	9,273,336		379,620
	41,443,486.53	18,352,569	21,130,913	20,312,574		795,232

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.5 1.92

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,680	1,706	263	6.59	40
1967	207.34	176	179	29	6.90	4
1968	820.82	689	699	121	7.22	17
1969	4,348.68	3,619	3,674	675	7.55	89
1970	585.40	483	490	95	7.89	12
1971	1,925.29	1,573	1,597	328	8.24	40
1972	16,780.77	13,577	13,783	2,998	8.59	349
2004	19,260.94	9,557	9,702	9,559	22.59	423
2005	22,925.98	10,961	11,127	11,798	23.20	509
	68,823.91	42,315	42,958	25,866		1,483

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.4 2.15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1929	141.00	141	141			
1955	2,275.45	2,004	2,034	241	5.37	45
1956	989.22	865	878	111	5.63	20
1957	545.83	474	481	65	5.90	11
1958	236.59	204	207	29	6.18	5
1959	739.15	633	643	97	6.46	15
1960	6,231.82	5,298	5,379	853	6.74	127
1961	5,465.73	4,612	4,682	784	7.03	112
1962	1,776.66	1,487	1,510	267	7.33	36
1963	1,519.13	1,262	1,281	238	7.62	31
1964	1,895.48	1,561	1,585	311	7.93	39
1965	611.14	499	507	105	8.24	13
1966	1,500.19	1,215	1,233	267	8.56	31
1967	7,810.50	6,269	6,364	1,446	8.88	163
1968	5,156.86	4,101	4,163	993	9.21	108
1969	2,743.23	2,162	2,195	548	9.54	57
1970	1,104.82	862	875	230	9.89	23
1971	31,924.90	24,660	25,035	6,890	10.24	673
1972	2,029.09	1,551	1,575	454	10.61	43
1973	5,741.28	4,340	4,406	1,335	10.98	122
1974	677.56	507	515	163	11.36	14
1975	501.75	371	377	125	11.76	11
1976	3,733.18	2,724	2,765	968	12.16	80
1977	1,421.54	1,024	1,040	382	12.57	30
1978	182.88	130	132	51	13.00	4
1979	5,235.99	3,672	3,728	1,508	13.44	112
1980	17,091.10	11,816	11,996	5,095	13.89	367
1981	121,509.06	82,761	84,020	37,489	14.35	2,612
1982	95,200.74	73,305	74,420	20,780	13.22	1,572
1983	6,768.10	5,152	5,230	1,538	13.57	113
1984	6,649.28	5,000	5,076	1,573	13.93	113
1985	25,257.56	18,650	18,934	6,324	14.61	433
1986	23,743.92	17,297	17,560	6,184	15.00	412
1987	25,830.88	18,554	18,836	6,995	15.39	455
1988	26,270.40	18,589	18,872	7,399	15.81	468
1989	52,802.47	36,782	37,342	15,461	16.22	953
1990	55,497.04	38,021	38,600	16,897	16.66	1,014
1991	30,826.21	20,755	21,071	9,755	17.10	570
1992	56,752.96	37,514	38,085	18,668	17.56	1,063
1993	45,455.69	29,473	29,921	15,534	18.03	862
1994	30,338.27	19,274	19,567	10,771	18.51	582

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1995	22,678.63	14,104	14,319	8,360	19.00	440
1996	22,335.06	13,580	13,787	8,548	19.50	438
1997	8,544.26	5,074	5,151	3,393	20.01	170
1998	8,784.27	5,087	5,164	3,620	20.53	176
1999	13,041.26	7,392	7,504	5,537	20.83	266
2000	2,551.99	1,407	1,428	1,124	21.37	53
2004	347.18	169	172	176	23.41	8
2005	3,317.00	1,565	1,589	1,728	23.79	73
2006	3,670.43	1,665	1,690	1,980	24.39	81
2010	54.74	21	21	33	26.05	1
2012	115,202.00	40,252	40,864	74,338	27.00	2,753
2013	22,348.33	7,393	7,505	14,843	27.31	544
2014	10,178.04	3,155	3,203	6,975	27.82	251
2015	1,657.77	480	487	1,170	28.18	42
2017	320.08	79	80	240	28.81	8
2018	4,740.95	1,072	1,088	3,653	29.09	126
2019	1,261.22	257	261	1,000	29.26	34
2024	123,717.60	9,836	9,986	113,732	28.95	3,929
2025	103,838.99	5,275	5,355	98,484	28.00	3,517
	1,180,774.45	623,434	632,918	547,856		26,424

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.7 2.24

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	282	291			
1990	10,556.06	10,178	10,556			
1991	4,510.10	4,308	4,510			
1992	3,050.56	2,894	3,051			
1993	5,858.48	5,513	5,858			
1994	335.37	313	335			
1997	104.02	94	104			
	24,705.16	23,582	24,705			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,369	1,369			
1952	1,125.65	1,124	1,126			
1953	30,125.92	29,908	30,126			
1954	5,517.65	5,446	5,518			
1955	601.79	590	602			
1956	8,337.58	8,121	8,338			
1957	1,905.18	1,843	1,905			
1958	651.12	625	651			
1959	15,785.61	15,052	15,786			
1960	2,005.39	1,899	2,005			
1961	1,960.14	1,843	1,960			
1962	288.11	269	288			
1963	1,039.65	965	1,040			
1964	5,769.25	5,324	5,769			
1965	1,751.72	1,607	1,752			
1966	3,912.12	3,567	3,912			
1967	4,863.78	4,408	4,864			
1968	8,062.42	7,262	8,062			
1969	1,581.42	1,415	1,581			
1970	2,285.43	2,033	2,285			
1971	10,974.98	9,696	10,975			
1972	4,046.99	3,552	4,047			
1974	1,652.12	1,429	1,652			
1975	8,480.27	7,285	8,480			
1976	7,949.17	6,775	7,949			
1977	2,458.86	2,078	2,459			
1978	1,265.56	1,061	1,266			
1979	752.79	625	753			
1980	1,718.37	1,413	1,718			
1981	10,162.67	8,272	10,163			
1982	12,027.61	10,325	12,028			
1983	1,755.64	1,496	1,756			
1984	30,831.09	25,923	30,831			
1985	13,068.42	10,889	13,068			
1986	19,569.87	16,147	19,570			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1987	23,586.65	19,164	23,587			
1988	13,276.05	10,663	13,276			
1989	15,968.66	12,610	15,871	98	9.92	10
1990	33,323.13	25,972	32,688	635	10.26	62
1991	26,014.16	19,898	25,043	971	10.83	90
1992	15,045.39	11,286	14,204	841	11.41	74
1993	23,968.53	17,694	22,269	1,699	11.79	144
1994	51,100.60	36,915	46,461	4,640	12.39	374
1995	69,990.02	49,651	62,490	7,500	12.80	586
1996	45,414.72	31,459	39,594	5,821	13.42	434
1997	84,495.34	57,094	71,858	12,638	14.04	900
1998	75,399.07	49,839	62,727	12,672	14.49	875
1999	119,656.29	76,951	96,849	22,807	15.12	1,508
2000	199,968.82	124,941	157,249	42,720	15.76	2,711
2001	116,038.59	70,609	88,867	27,171	16.24	1,673
2002	42,457.03	25,020	31,490	10,967	16.90	649
2003	222,013.40	126,459	159,159	62,854	17.57	3,577
2004	109,705.10	60,535	76,188	33,517	18.07	1,855
2005	70,405.76	37,400	47,071	23,335	18.75	1,245
2006	85,043.37	43,398	54,620	30,423	19.43	1,566
2007	37,304.93	18,313	23,048	14,256	19.96	714
2008	97,908.80	46,546	58,582	39,327	20.41	1,927
2009	42,499.78	19,261	24,242	18,258	21.11	865
2011	14,980.73	6,130	7,715	7,266	22.38	325
2013	30,446.98	11,058	13,917	16,530	23.67	698
2018	12,429.20	2,979	3,749	8,680	26.96	322
2019	31,358.25	6,704	8,438	22,921	27.59	831
2020	191,812.76	35,907	45,192	146,621	28.22	5,196
2022	92,398.23	12,270	15,443	76,955	29.40	2,618
2023	200,050.99	21,005	26,437	173,614	29.83	5,820
2024	76,548.71	5,833	7,341	69,207	30.29	2,285
2025	66,450.74	3,130	3,939	62,511	30.35	2,060
	2,602,976.26	1,338,592	1,645,521	957,455		41,994
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	430	461			
1976	21,500.00	18,323	21,500			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1984	1,544.96	1,299	1,545			
1987	5,496.89	4,466	5,497			
1988	2,425.60	1,948	2,426			
1997	821.60	555	800	22	14.04	2
2008	85,066.24	40,440	58,265	26,801	20.41	1,313
	117,316.10	67,461	90,493	26,823		1,315
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1914	0.25		0			
1919	46.40	46	46			
1920	65.00	65	65			
1924	288.57	289	289			
1926	8.25	8	8			
1927	265.80	266	266			
1928	32.00	32	32			
1929	401.84	402	402			
1930	576.33	576	576			
1931	862.24	862	862			
1932	179.53	180	180			
1935	339.96	340	340			
1936	180.10	180	180			
1937	702.11	702	702			
1938	70.20	70	70			
1939	114.20	114	114			
1941	93.19	93	93			
1946	107.86	108	108			
1947	228.20	228	228			
1950	115.54	116	116			
1951	399.62	400	400			
1953	526.32	523	526			
1954	866.71	855	867			
1955	3,485.13	3,417	3,485			
1956	166.98	163	167			
1957	807.41	781	807			
1958	3,980.48	3,823	3,980			
1959	3,557.12	3,392	3,557			
1960	940.90	891	941			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1961	2,160.12	2,031	2,160			
1962	2,440.64	2,280	2,441			
1963	1,463.53	1,359	1,464			
1964	852.14	786	852			
1965	4,391.44	4,028	4,391			
1966	7,725.03	7,043	7,725			
1967	9,375.01	8,496	9,375			
1968	1,802.13	1,623	1,802			
1969	4,312.49	3,860	4,312			
1970	727.19	647	727			
1971	12,970.95	11,460	12,971			
1972	4,161.73	3,653	4,162			
1973	5,521.13	4,812	5,521			
1974	4,072.92	3,524	4,073			
1975	1,691.94	1,453	1,687	5	5.64	1
1976	2,859.26	2,437	2,829	31	5.91	5
1977	9,079.27	7,674	8,907	172	6.19	28
1978	8,076.46	6,768	7,856	221	6.48	34
1979	16,025.59	13,309	15,448	578	6.78	85
1980	16,463.34	13,541	15,717	746	7.10	105
1981	18,913.59	15,396	17,870	1,043	7.44	140
1982	17,303.36	14,853	17,240	63	7.30	9
1983	24,489.09	20,865	24,218	271	7.51	36
1984	30,607.35	25,735	29,871	736	8.00	92
1985	47,810.95	39,836	46,238	1,573	8.26	190
1986	41,095.26	33,908	39,357	1,738	8.53	204
1987	31,108.85	25,276	29,338	1,771	9.06	195
1988	67,276.33	54,036	62,720	4,556	9.37	486
1989	73,855.80	58,324	67,697	6,159	9.92	621
1990	72,040.64	56,148	65,172	6,869	10.26	669
1991	46,648.02	35,681	41,415	5,233	10.83	483
1992	72,629.85	54,480	63,235	9,394	11.41	823
1993	50,628.58	37,374	43,380	7,248	11.79	615
1994	79,302.27	57,288	66,495	12,808	12.39	1,034
1995	207,257.72	147,029	170,658	36,600	12.80	2,859
1996	83,557.81	57,880	67,182	16,376	13.42	1,220
1997	20,844.66	14,085	16,349	4,496	14.04	320
1998	283,838.00	187,617	217,769	66,069	14.49	4,560
1999	62,321.83	40,079	46,520	15,802	15.12	1,045
2000	24,248.93	15,151	17,586	6,663	15.76	423
2006	20,518.49	10,471	12,154	8,365	19.43	431

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
2010	4,783.98	2,060	2,391	2,393	21.82	110
2014	897.06	304	353	544	24.40	22
2016	116,605.62	33,792	39,223	77,383	25.73	3,008
2017	219,792.43	58,245	67,606	152,187	26.34	5,778
2018	159,592.89	38,254	44,402	115,191	26.96	4,273
2019	186,196.01	39,809	46,207	139,989	27.59	5,074
2020	386,652.62	72,381	84,013	302,639	28.22	10,724
2022	1,515.12	201	233	1,282	29.40	44
	2,587,913.66	1,366,264	1,580,720	1,007,194		45,746
	5,308,206.02	2,772,317	3,316,734	1,991,472		89,055

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.4 1.68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,727	10,727			
2001	13,978.74	13,979	13,979			
2002	7,564.41	7,337	7,435	129	0.75	129
2003	93,599.07	87,047	88,211	5,388	1.75	3,079
	1,490,664.11	1,483,885	1,485,147	5,517		3,208

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.7 0.22

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1949	209.87	164	157	53	17.01	3
1950	29,615.55	23,094	22,153	7,462	17.08	437
1951	10,670.71	8,298	7,960	2,711	17.14	158
1952	14,491.73	11,235	10,777	3,714	17.21	216
1953	16,328.83	12,623	12,109	4,220	17.27	244
1954	227,196.45	175,103	167,971	59,225	17.33	3,417
1955	886.62	681	653	233	17.39	13
1956	784.04	600	576	208	17.45	12
1957	3,091.23	2,360	2,264	827	17.51	47
1958	1,599.00	1,217	1,167	432	17.56	25
1959	2,174.45	1,649	1,582	593	17.62	34
1960	4,772.90	3,607	3,460	1,313	17.67	74
1961	15,133.22	11,395	10,931	4,202	17.72	237
1962	10,958.88	8,222	7,887	3,072	17.77	173
1963	7,734.79	5,781	5,546	2,189	17.82	123
1964	9,913.13	7,381	7,080	2,833	17.87	159
1965	5,141.61	3,813	3,658	1,484	17.92	83
1966	314.20	232	223	92	17.97	5
1967	439.04	323	310	129	18.01	7
1968	1,616.81	1,184	1,136	481	18.05	27
1969	6,816.59	4,969	4,767	2,050	18.10	113
1970	2,722.51	1,976	1,896	827	18.14	46
1971	1,337.29	966	927	411	18.18	23
1972	542.89	390	374	169	18.22	9
1973	2,930.42	2,096	2,011	920	18.26	50
1978	1,595.57	1,110	1,065	531	18.43	29
1980	5,855.25	4,023	3,859	1,996	18.50	108
1983	14,563.97	10,204	9,788	4,776	18.48	258
1985	12,075.10	8,368	8,027	4,048	18.27	222
1988	50,822.82	34,214	32,820	18,002	18.57	969
1989	8,134.16	5,424	5,203	2,931	18.61	157
1990	119,522.68	79,291	76,061	43,461	18.39	2,363
1992	46,482.22	30,088	28,863	17,620	18.66	944
1994	1,681,826.46	1,068,464	1,024,945	656,881	18.51	35,488
1995	21,647.41	13,597	13,043	8,604	18.50	465
1996	2,209.20	1,370	1,314	895	18.53	48
1998	25,290.28	15,217	14,597	10,693	18.70	572
2000	8,182.31	4,790	4,595	3,587	18.59	193
2001	23,695.01	13,641	13,085	10,610	18.61	570
2002	46,225.52	26,117	25,053	21,172	18.67	1,134

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
2003	134,655.85	74,519	71,484	63,172	18.76	3,367
2004	71,976.80	39,076	37,484	34,492	18.73	1,842
2005	59,215.05	31,455	30,174	29,041	18.75	1,549
2012	73,653.39	32,142	30,833	42,821	18.72	2,287
2014	122,390.14	48,956	46,962	75,428	18.75	4,023
2015	9,307.57	3,532	3,388	5,919	18.80	315
2016	79,928.58	28,702	27,533	52,396	18.74	2,796
2018	20,489.88	6,393	6,133	14,357	18.75	766
2021	3,894.85	887	851	3,044	18.65	163
2022	85,495.25	16,654	15,976	69,520	18.60	3,738
2023	1,252,978.93	199,098	190,989	1,061,990	18.53	57,312
2024	350,064.83	41,938	40,230	309,835	18.38	16,857
2025	106,077.33	8,104	7,774	98,303	18.15	5,416
2026	2,694,379.96	74,904	71,853	2,622,527	17.49	149,944
	7,510,059.13	2,211,637	2,121,556	5,388,503		299,630
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1950	610.12	592	568	42	1.97	21
1951	798.68	775	743	55	1.98	28
1955	781,371.90	757,306	726,461	54,911	1.98	27,733
1956	1,022.16	990	950	72	1.98	36
1957	10,010.93	9,696	9,301	710	1.98	359
1958	2,426.80	2,350	2,254	173	1.98	87
1959	5,071.16	4,908	4,708	363	1.98	183
1960	4,844.36	4,687	4,496	348	1.98	176
1961	528,480.43	511,051	490,236	38,245	1.98	19,316
1962	332.41	321	308	24	1.98	12
1963	272.69	263	252	20	1.98	10
1966	3,794.52	3,661	3,512	283	1.98	143
1967	2,745.32	2,647	2,539	206	1.98	104
1969	853.41	822	789	65	1.98	33
1970	7,914.53	7,619	7,309	606	1.99	305
1971	18,141.01	17,452	16,741	1,400	1.99	704
1972	3,341.95	3,213	3,082	260	1.99	131
1973	2,823.39	2,713	2,602	221	1.99	111

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1974	1,197,475.89	1,149,828	1,102,995	94,481	1.99	47,478
1975	22,472.16	21,563	20,685	1,787	1.99	898
1976	32,399.32	31,067	29,802	2,598	1.99	1,306
1977	34,823.49	33,366	32,007	2,816	1.99	1,415
1978	14,111.37	13,510	12,960	1,152	1.99	579
1979	146,636.85	140,277	134,563	12,073	1.99	6,067
1980	455,488.61	435,365	417,632	37,856	1.99	19,023
1981	56,841.26	54,282	52,071	4,770	1.99	2,397
1982	38,228.67	36,539	35,051	3,178	2.05	1,550
1983	2,887.71	2,760	2,648	240	2.00	120
1984	88,945.57	84,925	81,466	7,480	2.00	3,740
1985	30,381.98	28,951	27,772	2,610	2.04	1,279
1986	138,905.95	132,502	127,105	11,801	1.95	6,052
1987	3,303.33	3,138	3,010	293	2.07	142
1988	2,075.89	1,977	1,896	179	1.91	94
1989	956,867.30	908,928	871,907	84,960	1.96	43,347
1990	705,105.44	669,709	642,432	62,674	1.92	32,643
1991	54,931.83	52,086	49,965	4,967	1.93	2,574
1992	342,642.46	323,900	310,707	31,935	1.98	16,129
1993	36,768.29	34,720	33,306	3,462	1.96	1,766
1994	333,820.57	314,359	301,555	32,266	2.00	16,133
1995	34,350.86	32,310	30,994	3,357	1.97	1,704
1996	43,093.01	40,413	38,767	4,326	2.01	2,152
1997	10,160.87	9,511	9,124	1,037	2.00	518
1998	246,501.13	230,503	221,115	25,387	1.96	12,953
2000	1,451,492.70	1,348,727	1,293,793	157,700	2.00	78,850
2001	374,089.68	346,669	332,549	41,541	2.00	20,770
2002	172,808.53	159,658	153,155	19,653	2.00	9,826
2003	199,381.10	183,570	176,093	23,288	2.00	11,644
2004	199,439.57	182,826	175,379	24,060	2.02	11,911
2005	505,783.84	462,185	443,360	62,424	2.00	31,212
2006	72,390.46	65,962	63,275	9,115	1.97	4,627
2007	742,477.73	673,205	645,785	96,693	1.98	48,835
2008	545,431.06	492,415	472,359	73,072	1.99	36,720
2009	131,767.71	118,301	113,483	18,285	1.99	9,188
2010	91,858.54	81,993	78,653	13,205	1.99	6,636
2011	74,795.31	66,314	63,613	11,182	1.98	5,647
2012	248,536.67	218,389	209,494	39,043	2.00	19,522
2013	35,863.44	31,230	29,958	5,905	2.00	2,952
2014	290,090.29	250,203	240,012	50,078	1.99	25,165

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
2015	381,588.36	325,190	311,945	69,643	1.99	34,996
2016	806,498.45	677,459	649,866	156,633	2.00	78,316
2017	171,660.23	141,877	136,098	35,562	1.99	17,870
2018	1,009,650.14	817,817	784,507	225,143	1.99	113,137
2019	2,115,980.64	1,671,202	1,603,133	512,847	2.00	256,424
2020	9,658.70	7,389	7,088	2,571	2.00	1,286
2021	236,790.51	173,733	166,657	70,134	2.00	35,067
2022	1,973,286.58	1,367,488	1,311,790	661,497	1.99	332,411
2023	1,260,312.35	802,819	770,120	490,192	1.99	246,328
2024	482,886.44	268,726	257,781	225,106	1.99	113,119
2025	2,255,822.13	969,101	929,629	1,326,193	1.99	666,429
2026	1,370,155.70	275,538	264,315	1,105,840	1.99	555,698
	23,614,572.44	18,297,541	17,552,277	6,062,295		3,046,137
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
1969	6,798.01	3,731	3,579	3,219	36.86	87
1970	3,383.06	1,839	1,764	1,619	37.12	44
1989	25,957.50	12,859	12,335	13,622	37.94	359
1992	58,567.66	27,480	26,361	32,207	38.74	831
1994	10,549.87	4,797	4,602	5,948	38.67	154
2002	4,127.48	1,561	1,497	2,630	39.85	66
2005	2,644.58	922	884	1,760	39.73	44
2010	2,788.23	814	781	2,007	40.00	50
2011	36,615.99	10,216	9,800	26,816	40.06	669
2014	167,443.92	39,768	38,148	129,296	40.13	3,222
2015	204,441.65	45,611	43,753	160,688	40.05	4,012
2016	539,847.11	112,234	107,663	432,184	40.01	10,802
2018	842,885.66	148,348	142,306	700,580	39.81	17,598
2019	4,975.51	791	759	4,217	39.67	106
2021	103,857.62	12,733	12,214	91,643	39.35	2,329
2022	24,312.57	2,516	2,414	21,899	38.98	562

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
2023	14,599,888.58	1,216,171	1,166,636	13,433,253	38.52	348,735
2024	12,255,071.05	759,814	728,867	11,526,204	37.82	304,765
2025	1,920,001.92	75,264	72,198	1,847,803	36.81	50,198
	30,814,157.97	2,477,469	2,376,561	28,437,597		744,633
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1933	657.93	553	530	127	13.21	10
1992	1,969,044.37	1,369,077	1,313,314	655,730	15.01	43,686
1993	15,226.14	10,480	10,053	5,173	15.06	343
1994	10,056.65	6,844	6,565	3,491	15.14	231
2000	1,880.00	1,194	1,145	735	15.07	49
2001	34,203.52	21,418	20,546	13,658	15.07	906
2021	22,887.76	6,106	5,857	17,030	15.12	1,126
2022	3,729.30	858	823	2,906	15.07	193
2023	23,764.21	4,491	4,308	19,456	15.02	1,295
2024	18,478.82	2,646	2,538	15,941	14.95	1,066
2025	79,939.97	7,354	7,054	72,886	14.81	4,921
	2,179,868.67	1,431,021	1,372,735	807,134		53,826
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2009	4,797,873.14	1,788,647	1,715,795	3,082,078	29.45	104,655
2011	174,377.96	60,003	57,559	116,819	29.55	3,953
2021	84,360.17	13,413	12,867	71,493	29.10	2,457
2022	1,292,527.36	174,491	167,384	1,125,143	28.83	39,027
2023	118,404.34	12,882	12,357	106,047	28.66	3,700
2024	87,895.68	7,137	6,846	81,049	28.27	2,867
2025	116,849.61	5,994	5,750	111,100	27.74	4,005
	6,672,288.26	2,062,567	1,978,558	4,693,730		160,664

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - GAS TRAINING CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2021	31,183,853.56	4,013,362	3,849,897	27,333,957	37.24	733,995
2022	3,002,042.24	325,421	312,167	2,689,876	37.00	72,699
2023	29,706.91	2,599	2,493	27,214	36.50	746
2024	21,138.08	1,374	1,318	19,820	35.96	551
2025	30,709.16	1,262	1,211	29,499	35.00	843
	34,267,449.95	4,344,018	4,167,085	30,100,365		808,834
UGI-GAS - WELLSBORO						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2026	5,893,983.14	89,589	85,940	5,808,043	32.39	179,316
	5,893,983.14	89,589	85,940	5,808,043		179,316
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1938	143.77	144	144			
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	401	401			
1949	1,806.43	1,806	1,806			
1950	2,196.55	2,197	2,197			
1951	233.36	233	233			
1953	27,799.96	27,598	26,413	1,387	0.29	1,387
1954	20,454.90	20,189	19,322	1,133	0.52	1,133
1955	3,292.27	3,228	3,089	203	0.78	203
1957	1,355.54	1,311	1,255	101	1.31	77
1958	5,763.15	5,536	5,298	465	1.58	294
1959	1,958.52	1,867	1,787	172	1.86	92
1960	3,574.90	3,384	3,239	336	2.14	157
1961	649.28	610	584	65	2.42	27
1962	9,412.34	8,777	8,400	1,012	2.70	375
1963	12,936.88	11,970	11,456	1,481	2.99	495
1964	3,052.55	2,802	2,682	371	3.28	113
1966	2,516.15	2,273	2,175	341	3.86	88
1967	1,274.89	1,143	1,094	181	4.15	44
1968	419.83	373	357	63	4.45	14
1970	731.03	639	612	119	5.04	24
1971	10,643.95	9,223	8,827	1,817	5.34	340
1972	1,090.13	936	896	194	5.64	34
1975	164.27	137	131	33	6.59	5
1976	24,200.07	20,007	19,148	5,052	6.93	729
1977	7,165.00	5,863	5,611	1,554	7.27	214
1978	8,046.84	6,512	6,232	1,814	7.63	238
1979	4,081.97	3,266	3,126	956	8.00	120
1980	13,629.88	10,774	10,311	3,319	8.38	396
1983	369.74	307	294	76	8.83	9
1985	27,096.76	22,019	21,073	6,023	9.51	633
1986	5,526.05	4,426	4,236	1,290	10.00	129
1988	338.67	264	253	86	10.77	8
1989	19,959.70	15,317	14,659	5,300	11.29	469
1990	1,194.94	905	866	329	11.60	28
1991	5,163.03	3,840	3,675	1,488	12.14	123
1992	7,676.31	5,627	5,385	2,291	12.48	184
1994	38,494.90	27,189	26,021	12,473	13.41	930
1995	28,542.82	19,712	18,866	9,677	14.00	691

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1997	46,847.50	30,966	29,636	17,211	15.00	1,147
1998	39,421.11	25,502	24,407	15,014	15.42	974
1999	72,667.26	45,744	43,780	28,888	16.04	1,801
2000	38,962.96	23,931	22,903	16,060	16.49	974
2001	110,913.42	66,093	63,255	47,659	17.12	2,784
2002	39,331.76	22,797	21,818	17,514	17.59	996
2003	35,150.00	19,695	18,849	16,301	18.24	894
2004	52,683.27	28,602	27,374	25,309	18.73	1,351
2005	302,659.69	158,866	152,044	150,616	19.23	7,832
2006	139,043.00	70,384	67,362	71,681	19.75	3,629
2007	78,002.02	37,839	36,214	41,788	20.43	2,045
2011	148,951.37	60,713	58,106	90,845	22.52	4,034
2012	1,935.54	747	715	1,221	23.09	53
2013	5,265.73	1,919	1,837	3,429	23.54	146
2014	187,584.86	64,004	61,256	126,329	24.13	5,235
2015	20,002.66	6,349	6,076	13,926	24.73	563
2016	52,555.80	15,451	14,788	37,768	25.21	1,498
2017	28,421.86	7,668	7,339	21,083	25.71	820
2018	276,078.65	67,584	64,682	211,397	26.22	8,062
2019	737,164.05	161,439	154,507	582,657	26.75	21,782
2020	469,675.04	90,647	86,754	382,921	27.17	14,094
2021	305,923.54	50,814	48,632	257,292	27.61	9,319
2022	4,000.00	554	530	3,470	27.97	124
2023	4,502.00	498	477	4,025	28.15	143
2024	174,756.78	14,190	13,581	161,176	28.27	5,701
2025	11,517.54	585	560	10,958	28.00	391
	3,754,319.25	1,393,328	1,336,578	2,417,741		106,195
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	100,930.51	74,970	90,272	10,659	18.82	566
1961	86,871.16	64,268	77,385	9,486	18.89	502
1962	141,136.69	104,025	125,257	15,880	18.94	838
1963	9,480.45	6,959	8,379	1,101	19.00	58
1964	3,689.12	2,697	3,247	442	19.06	23
1965	479.00	349	420	59	19.11	3
1966	297.39	216	260	37	19.17	2

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1967	860.37	621	748	113	19.22	6
1968	3,570.31	2,564	3,087	483	19.27	25
1969	661.27	473	570	92	19.32	5
1970	2,325.05	1,654	1,992	333	19.37	17
1971	74,835.43	52,979	63,792	11,043	19.41	569
1972	5,279.41	3,718	4,477	803	19.46	41
1973	5,863.34	4,107	4,945	918	19.51	47
1974	1,077.54	751	904	173	19.55	9
1975	20,112.15	13,934	16,778	3,334	19.59	170
1976	98,397.02	67,777	81,610	16,787	19.63	855
1977	262,518.62	179,725	216,407	46,111	19.67	2,344
1978	14,862.88	10,113	12,177	2,686	19.71	136
1979	31,316.64	21,169	25,490	5,827	19.75	295
1980	50,253.77	33,742	40,629	9,625	19.79	486
1981	48,963.34	32,653	39,318	9,646	19.82	487
1982	16,098.09	11,183	13,465	2,633	19.45	135
1983	15,919.21	10,948	13,183	2,737	19.64	139
1984	47,604.50	32,581	39,231	8,374	19.48	430
1985	68,749.88	46,509	56,002	12,748	19.73	646
1986	220,372.23	148,134	178,369	42,004	19.63	2,140
1987	95,726.84	63,869	76,905	18,822	19.58	961
1988	78,940.78	52,235	62,896	16,044	19.55	821
1989	133,833.58	87,246	105,053	28,780	19.89	1,447
1990	1,474.46	957	1,152	322	19.61	16
1991	12,756.63	8,185	9,856	2,901	19.69	147
1992	108,291.24	68,613	82,617	25,674	19.81	1,296
1993	238,990.24	149,393	179,884	59,106	19.94	2,964
1994	9,228.65	5,714	6,880	2,348	19.83	118
1995	133,112.29	81,531	98,172	34,941	19.77	1,767
1996	77,622.54	46,729	56,267	21,356	20.00	1,068
1997	4,624,824.64	2,746,221	3,306,732	1,318,093	20.01	65,872
1998	280,621.46	164,107	197,602	83,020	20.06	4,139
1999	84,872.92	49,031	59,038	25,835	19.92	1,297
2000	89,743.66	50,885	61,271	28,473	20.05	1,420
2001	725,398.24	404,772	487,387	238,011	20.00	11,901
2002	42,268.05	23,163	27,891	14,377	20.00	719
2003	180,782.36	97,098	116,916	63,866	20.04	3,187
2004	146,160.24	76,749	92,414	53,747	20.12	2,671
2005	167,022.30	85,883	103,412	63,610	20.07	3,169
2006	140,015.92	70,316	84,668	55,348	20.07	2,758

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2007	877,150.17	428,926	516,471	360,679	20.12	17,926
2008	79,300.50	38,001	45,757	33,543	20.11	1,668
2009	54,131.55	25,198	30,341	23,791	20.09	1,184
2010	196,247.48	88,390	106,431	89,817	20.13	4,462
2011	314,990.40	137,210	165,215	149,775	20.09	7,455
2012	49,422.81	20,708	24,935	24,488	20.10	1,218
2013	122,684.15	49,356	59,430	63,254	20.06	3,153
2014	163,988.66	62,939	75,785	88,204	20.07	4,395
2015	94,908.17	34,604	41,667	53,241	20.04	2,657
2016	608,702.23	209,028	251,691	357,011	20.08	17,779
2017	14,886.51	4,780	5,756	9,131	20.09	455
2025	4,028.00	289	348	3,680	19.38	190
	11,284,653.04	6,360,945	7,659,230	3,625,423		181,254
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	25,060	27,375			
1961	2,250.14	2,058	2,250			
1962	11,395.40	10,408	11,395			
1964	212.41	194	212			
1965	479.69	437	480			
1972	4,846.95	4,367	4,847			
1973	59,338.04	53,371	59,338			
1976	674.99	604	675			
1977	9,114.69	8,139	9,115			
1978	24,124.85	21,494	24,125			
1979	540.75	481	541			
1980	8,726.53	7,742	8,727			
1981	52,430.77	46,414	52,431			
1982	22,292.87	19,827	22,293			
1984	11,417.15	10,129	11,417			
1986	31,130.64	27,442	31,131			
1987	11,362.33	9,990	11,362			
1988	15,773.37	13,816	15,773			
1989	8,654.63	7,543	8,655			
1990	94,337.02	82,073	94,337			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1992	6,049.58	5,221	6,050			
1993	1,598.34	1,376	1,598			
1994	38,859.45	33,209	38,859			
1995	4,586.75	3,913	4,587			
1996	1,532.27	1,298	1,532			
1997	1,129.92	952	1,130			
1998	3,483.10	2,922	3,483			
2001	6,551.41	5,393	6,551			
2002	8,685.69	7,098	8,686			
2003	26,975.97	21,888	26,976			
2004	262,708.52	211,007	262,709			
2005	28,203.02	22,475	28,164	39	5.42	7
2008	29,302.79	22,660	28,396	907	5.42	167
2010	189,349.18	142,466	178,527	10,823	5.43	1,993
2011	217,404.63	160,749	201,437	15,967	5.46	2,924
2014	19,697.18	13,713	17,184	2,513	5.45	461
2016	36,430.01	23,986	30,057	6,373	5.45	1,169
2020	4,772.90	2,596	3,253	1,520	5.45	279
	1,283,798.91	1,034,511	1,245,657	38,142		7,000
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2001	6,628.41	3,380	4,070	2,559	24.26	105
2002	3,783,335.80	1,890,155	2,275,940	1,507,395	24.29	62,058
2003	87,794.37	43,072	51,863	35,931	24.14	1,488
2004	116,222.01	55,601	66,949	49,273	24.26	2,031
2005	21,321.99	9,968	12,002	9,319	24.20	385
2006	70,501.63	32,121	38,677	31,825	24.20	1,315
2007	23,909.23	10,587	12,748	11,161	24.23	461
2008	36,082.96	15,620	18,808	17,275	24.24	713
2009	2,440.34	1,021	1,229	1,211	24.34	50
2010	44,187.56	17,861	21,506	22,681	24.32	933
2011	22,823.04	8,878	10,690	12,133	24.34	498
2012	5,700.89	2,133	2,568	3,133	24.26	129
2013	10,921.02	3,892	4,686	6,235	24.38	256
2014	82,583.84	28,079	33,810	48,774	24.26	2,010

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2015	2,300.95	738	889	1,412	24.34	58
2016	41,558.96	12,526	15,083	26,476	24.34	1,088
2021	94,830.25	17,629	21,227	73,603	24.09	3,055
2022	973,757.93	153,854	185,256	788,502	23.99	32,868
2023	81,823.98	10,482	12,621	69,203	23.82	2,905
2024	301,308.21	28,865	34,756	266,552	23.61	11,290
2025	136,691.16	8,311	10,007	126,684	23.19	5,463
	5,946,724.53	2,354,773	2,835,388	3,111,337		129,159
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
2014	780,161.32	230,148	277,121	503,040	29.87	16,841
2015	32,204.52	8,963	10,792	21,412	29.82	718
2016	12,899.16	3,359	4,045	8,855	29.82	297
2022	25,185.45	3,355	4,040	21,146	29.28	722
2023	69,633.76	7,507	9,039	60,595	28.97	2,092
2025	6,818.51	346	417	6,402	28.09	228
	926,902.72	253,678	305,454	621,449		20,898
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	277,375.43	240,346	277,375			
1972	810.87	697	811			
1973	1,434.30	1,221	1,434			
1974	13,712.41	11,563	13,712			
1975	145,445.34	121,483	145,445			
1976	281,929.40	233,085	281,719	211	6.93	30
1978	1,775.78	1,437	1,737	39	7.63	5
1983	1,771.86	1,471	1,772			
1984	8,465.79	6,939	8,387	79	9.30	8
1986	1,505.75	1,206	1,458	48	10.00	5
1987	64,760.94	51,342	62,055	2,706	10.26	264

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1988	168,597.14	131,556	159,006	9,591	10.77	891
1989	18,562.94	14,245	17,217	1,346	11.29	119
1990	3,332.27	2,525	3,052	280	11.60	24
1992	916.74	672	812	105	12.48	8
1994	8,578.71	6,059	7,323	1,255	13.41	94
1995	476.06	329	398	78	14.00	6
1996	2,292.46	1,553	1,877	415	14.39	29
1997	23,367.46	15,446	18,669	4,699	15.00	313
1998	20,830.73	13,475	16,287	4,544	15.42	295
1999	5,006.78	3,152	3,810	1,197	16.04	75
2000	410,430.38	252,086	304,685	105,745	16.49	6,413
2001	15,882.00	9,464	11,439	4,443	17.12	260
2002	131,970.21	76,490	92,450	39,520	17.59	2,247
2003	14,227.00	7,971	9,634	4,593	18.24	252
2004	40,853.63	22,179	26,807	14,047	18.73	750
2005	19,984.33	10,490	12,679	7,306	19.23	380
2007	63,158.66	30,638	37,031	26,128	20.43	1,279
2008	2,281.90	1,077	1,302	980	20.71	47
2009	9,274.10	4,171	5,041	4,233	21.41	198
2010	66,284.82	28,436	34,369	31,916	21.96	1,453
2011	413,084.05	168,373	203,505	209,579	22.52	9,306
2012	84,169.43	32,464	39,238	44,932	23.09	1,946
2014	114,113.87	38,936	47,060	67,054	24.13	2,779
2015	184,021.78	58,409	70,596	113,425	24.73	4,587
2016	68,436.37	20,120	24,318	44,118	25.21	1,750
2017	414,508.91	111,835	135,170	279,339	25.71	10,865
2018	669,488.04	163,891	198,088	471,400	26.22	17,979
2019	2,147,342.29	470,268	568,392	1,578,951	26.75	59,026
2020	717,532.95	138,484	167,379	550,154	27.17	20,249
2021	1,698,287.37	282,086	340,945	1,357,343	27.61	49,161
2022	2,087,632.04	289,346	349,719	1,737,913	27.97	62,135
2023	787,456.49	87,093	105,265	682,191	28.15	24,234
2024	858,356.26	69,699	84,242	774,114	28.27	27,383
2025	454,624.16	23,095	27,914	426,710	28.00	15,240
2026	279,618.45	5,201	6,286	273,332	26.45	10,334
	12,803,968.65	3,262,104	3,927,909	8,876,060		332,419

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1969	2,453.00	2,173	2,453			
1970	872.29	771	872			
1976	342.77	299	343			
1988	1,813.00	1,546	1,813			
1990	11,104.08	9,379	11,104			
1992	1,829.56	1,535	1,830			
1993	164,577.50	137,356	164,409	169	6.59	26
1994	8,948.74	7,417	8,878	71	6.66	11
1995	553.43	457	547	6	6.63	1
1996	6,824.90	5,595	6,697	128	6.65	19
1997	2,764.61	2,256	2,700	64	6.59	10
1999	58,743.84	47,224	56,525	2,219	6.65	334
2000	1,983.26	1,583	1,895	88	6.64	13
2005	3,338.96	2,540	3,040	299	6.68	45
2006	4,214.76	3,175	3,800	414	6.63	62
2008	49,021.21	36,001	43,092	5,930	6.69	886
2010	2,592.10	1,848	2,212	380	6.65	57
2011	12,791.22	8,941	10,702	2,089	6.67	313
2015	244,901.72	154,900	185,408	59,493	6.68	8,906
2016	106,882.55	65,316	78,180	28,702	6.68	4,297
2017	7,718.68	4,532	5,425	2,294	6.68	343
2018	17,640.50	9,882	11,828	5,812	6.67	871
2021	63,475.20	28,697	34,349	29,126	6.67	4,367
2022	2,400.00	968	1,159	1,241	6.66	186
2023	7,122.00	2,456	2,940	4,182	6.65	629
2025	3,950.00	729	873	3,077	6.62	465
	788,859.88	537,576	643,073	145,787		21,841
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1989	127.23	91	109	18	15.10	1
1992	758,027.04	527,056	630,488	127,539	15.01	8,497
1993	3,146.41	2,166	2,591	555	15.06	37
1994	8,657.45	5,891	7,047	1,610	15.14	106
1995	2,701.38	1,823	2,181	521	15.05	35
1996	9,933.05	6,640	7,943	1,990	15.00	133

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1998	1,738.51	1,135	1,358	381	15.04	25
2000	420,169.40	266,892	319,268	100,901	15.07	6,695
2002	79,118.01	48,737	58,301	20,817	15.12	1,377
2003	8,394.64	5,094	6,094	2,301	15.07	153
2004	30,839.56	18,322	21,918	8,922	15.20	587
2005	11,025.37	6,443	7,707	3,318	15.11	220
2006	34,349.48	19,614	23,463	10,886	15.21	716
2009	48,535.59	25,991	31,092	17,444	15.18	1,149
2010	16,891.81	8,807	10,535	6,356	15.15	420
2012	6,549.63	3,200	3,828	2,722	15.18	179
2014	117,924.70	53,208	63,650	54,275	15.20	3,571
2015	37,408.06	16,130	19,295	18,113	15.17	1,194
2016	10,340.67	4,235	5,066	5,275	15.14	348
2018	11,932.98	4,291	5,133	6,800	15.14	449
2019	5,810.76	1,926	2,304	3,507	15.12	232
2021	4,225.20	1,127	1,348	2,877	15.12	190
2022	126,600.86	29,118	34,832	91,769	15.07	6,090
2023	61,685.87	11,659	13,947	47,739	15.02	3,178
2024	53,568.54	7,671	9,176	44,392	14.95	2,969
2025	14,313.88	1,317	1,575	12,738	14.81	860
	1,884,016.08	1,078,584	1,290,251	593,765		39,411
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1936	1,234.84	974	1,165	70	17.79	4
1960	294.42	215	257	37	19.95	2
1969	377.45	265	317	60	20.52	3
1975	1,808.65	1,227	1,468	341	20.83	16
1981	26,509.40	17,278	20,669	5,841	21.10	277
1986	357.42	236	282	75	20.73	4
1987	95.00	62	74	21	20.99	1
1988	24.29	16	19	5	20.92	
1989	2,123.00	1,360	1,627	496	20.89	24
1991	4,760.80	2,987	3,573	1,188	20.93	57
1992	2,703.40	1,676	2,005	698	21.00	33
1994	18,973.34	11,443	13,689	5,285	21.22	249

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1995	4,307.22	2,571	3,076	1,232	21.10	58
1996	9,271.45	5,440	6,508	2,764	21.30	130
1997	11,191.78	6,482	7,754	3,438	21.25	162
1999	519,130.02	291,440	348,634	170,496	21.29	8,008
2000	12,387.00	6,828	8,168	4,219	21.37	197
2002	2,306.86	1,231	1,473	834	21.20	39
2003	6,184.42	3,221	3,853	2,331	21.39	109
2008	184,472.34	85,669	102,481	81,991	21.34	3,842
2014	17,931.59	6,613	7,911	10,021	21.40	468
2017	149,837.36	46,120	55,171	94,667	21.36	4,432
2022	15,322.66	2,689	3,217	12,106	21.14	573
	991,604.71	496,043	593,389	398,216		18,688
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1910	2,631.33	2,631	2,631			
1914	4,425.79	4,426	4,426			
1921	34.95	35	35			
1928	48,718.14	48,718	48,718			
1929	5,726.24	5,726	5,726			
1930	738.76	739	739			
1931	1,329.50	1,330	1,330			
1936	459.65	460	460			
1937	798.45	798	798			
1938	66.22	66	66			
1939	505.95	506	506			
1944	20.08	20	20			
1946	1,700.00	1,700	1,700			
1948	153.57	154	154			
1949	3,419.22	3,419	3,419			
1953	114.00	113	114			
1954	3,369.90	3,326	3,370			
1958	10,313.10	9,906	10,313			
1959	27,782.48	26,491	27,782			
1960	1,594.52	1,509	1,595			
1961	1,314.41	1,235	1,314			
1962	614.41	573	614			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1963	746.64	691	747			
1964	861.27	791	861			
1965	1,553.29	1,415	1,553			
1966	104,751.07	94,643	104,751			
1967	23,858.73	21,383	23,859			
1968	4,640.61	4,124	4,641			
1969	2,008.79	1,771	2,009			
1970	2,014.32	1,761	2,014			
1971	4,281.55	3,710	4,282			
1972	2,776.85	2,385	2,777			
1973	3,268.03	2,782	3,268			
1974	12,868.29	10,851	12,868			
1976	487.18	403	485	2	6.93	
1977	3,675.13	3,007	3,618	57	7.27	8
1978	423.97	343	413	11	7.63	1
1979	1,309.69	1,048	1,261	49	8.00	6
1980	4,025.99	3,183	3,830	196	8.38	23
1981	4,614.96	3,603	4,335	280	8.77	32
1982	11,408.95	9,593	11,409			
1983	500.00	415	499	1	8.83	
1984	12,832.20	10,517	12,653	179	9.30	19
1985	1,022.46	831	1,000	23	9.51	2
1987	1,781.17	1,412	1,699	82	10.26	8
1988	13,848.31	10,806	13,001	847	10.77	79
1989	1,502.94	1,153	1,387	116	11.29	10
1990	236,214.33	178,956	215,310	20,904	11.60	1,802
1991	44,551.84	33,138	39,870	4,682	12.14	386
1992	18,016.03	13,206	15,889	2,127	12.48	170
1993	112,769.99	80,991	97,444	15,326	13.05	1,174
1994	123,184.01	87,005	104,680	18,504	13.41	1,380
1995	39,025.60	26,951	32,426	6,600	14.00	471
1996	716,749.96	485,670	584,332	132,418	14.39	9,202
1997	241,538.51	159,657	192,091	49,448	15.00	3,297
1998	247,918.65	160,379	192,959	54,959	15.42	3,564
1999	79,405.90	49,986	60,140	19,265	16.04	1,201
2000	174,727.70	107,318	129,119	45,609	16.49	2,766
2001	48,581.99	28,950	34,831	13,751	17.12	803
2002	58,988.30	34,190	41,136	17,853	17.59	1,015
2003	627,003.27	351,310	422,677	204,326	18.24	11,202
2004	750,267.81	407,320	490,065	260,203	18.73	13,892
2005	265,792.85	139,515	167,857	97,936	19.23	5,093

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2006	119,100.02	60,288	72,535	46,565	19.75	2,358
2007	186,501.60	90,472	108,851	77,651	20.43	3,801
2008	816,679.27	385,309	463,583	353,097	20.71	17,050
2009	11,819.05	5,316	6,396	5,423	21.41	253
2010	134,277.17	57,605	69,307	64,970	21.96	2,959
2011	71,427.96	29,114	35,028	36,400	22.52	1,616
2012	72,706.86	28,043	33,740	38,967	23.09	1,688
2013	141,679.13	51,642	62,133	79,546	23.54	3,379
2014	264,648.26	90,298	108,642	156,007	24.13	6,465
2015	294,495.93	93,473	112,462	182,034	24.73	7,361
2016	193,954.73	57,023	68,607	125,348	25.21	4,972
2017	115,906.28	31,272	37,625	78,282	25.71	3,045
2018	290,104.93	71,018	85,445	204,660	26.22	7,805
2019	608,960.07	133,362	160,454	448,506	26.75	16,767
2020	519,803.19	100,322	120,702	399,101	27.17	14,689
2021	743,188.51	123,444	148,521	594,667	27.61	21,538
2022	1,585,043.09	219,687	264,315	1,320,728	27.97	47,219
2023	3,888,868.40	430,109	517,484	3,371,385	28.15	119,765
2024	473,610.79	38,457	46,269	427,341	28.27	15,116
2025	2,737,174.93	139,048	167,295	2,569,880	28.00	91,781
	17,391,579.97	4,886,346	5,845,267	11,546,313		447,233
	168,008,807.30	52,571,730	55,336,908	112,671,900		6,597,138

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.1 3.93

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.3 CNG STATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-S3						
NET SALVAGE PERCENT.. 0						
2026	7,022,613.60	251,410	251,058	6,771,556	13.49	501,969
	7,022,613.60	251,410	251,058	6,771,556		501,969
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					13.5	7.15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	98,862.25	95,155	82,080	16,782	0.75	16,782
2008	10,904.48	10,087	8,701	2,203	1.50	1,469
2009	196,763.79	172,168	148,511	48,252	2.50	19,301
2010	29,674.64	24,482	21,118	8,557	3.50	2,445
2013	49,177.44	33,195	28,634	20,544	6.50	3,161
2014	164,928.32	103,080	88,916	76,012	7.50	10,135
2015	142,233.63	81,784	70,546	71,687	8.50	8,434
2016	156,448.43	82,135	70,849	85,599	9.50	9,010
2017	694,772.06	330,017	284,671	410,101	10.50	39,057
2018	365,293.03	155,250	133,918	231,375	11.50	20,120
2019	260,157.81	97,559	84,154	176,004	12.50	14,080
2020	246,448.03	80,096	69,090	177,358	13.50	13,138
2021	1,078,784.33	296,666	255,903	822,882	14.50	56,750
2022	104,987.55	23,622	20,376	84,611	15.50	5,459
2023	12,578.55	2,201	1,899	10,680	16.50	647
2024	849.08	106	91	758	17.50	43
2026	50,000.00	1,250	1,078	48,922	19.50	2,509
	3,662,863.42	1,588,853	1,370,537	2,292,326		222,540
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	1,312.22	1,263	1,312			
2008	24,417.03	22,586	24,088	329	1.50	219
2010	2,239.24	1,847	1,970	269	3.50	77
2011	20,678.25	16,026	17,092	3,587	4.50	797
2014	33,759.66	21,100	22,503	11,257	7.50	1,501
2015	35,177.20	20,227	21,572	13,605	8.50	1,601
2016	233,275.70	122,470	130,613	102,662	9.50	10,807
2017	400,100.57	190,048	202,685	197,416	10.50	18,802
2018	31,187.62	13,255	14,136	17,051	11.50	1,483
2019	69,735.23	26,151	27,890	41,845	12.50	3,348
2020	115,739.37	37,615	40,116	75,623	13.50	5,602
2021	147,329.19	40,516	43,210	104,119	14.50	7,181
2022	100,538.69	22,621	24,125	76,414	15.50	4,930
2023	16,822.55	2,944	3,140	13,683	16.50	829

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2024	4,362.42	545	581	3,781	17.50	216
2025	7,898.56	592	631	7,267	18.50	393
2026	50,000.00	1,250	1,333	48,667	19.50	2,496
	1,294,573.50	541,056	576,998	717,576		60,282
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	4,828.41	4,647	4,400	428	0.75	428
2009	1,926.82	1,686	1,596	330	2.50	132
2013	4,225.61	2,852	2,700	1,525	6.50	235
2014	54,667.08	34,167	32,352	22,315	7.50	2,975
2015	9,361.71	5,383	5,097	4,265	8.50	502
2016	22,950.78	12,049	11,409	11,542	9.50	1,215
2017	31,887.57	15,147	14,342	17,545	10.50	1,671
2018	64,576.87	27,445	25,987	38,590	11.50	3,356
2019	9,728.37	3,648	3,454	6,274	12.50	502
2020	395,875.29	128,659	121,824	274,051	13.50	20,300
2021	6,256.54	1,721	1,630	4,627	14.50	319
2022	279,971.38	62,994	59,648	220,324	15.50	14,214
	886,256.43	300,398	284,440	601,816		45,849
	5,843,693.35	2,430,307	2,231,975	3,611,718		328,671

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.0 5.62

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	3,747.59	3,560	2,991	756	0.50	756
2020	18,196.00	11,827	9,938	8,258	3.50	2,359
2021	41,085.52	22,597	18,988	22,097	4.50	4,910
	63,029.11	37,984	31,918	31,111		8,025
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	8,554.22	8,127	7,643	911	0.50	911
2018	2,800.72	2,381	2,239	562	1.50	375
2019	4,541.15	3,406	3,203	1,338	2.50	535
2021	79,835.69	43,910	41,294	38,542	4.50	8,565
2023	2,910.37	1,019	958	1,952	6.50	300
2026	50,000.00	2,500	2,351	47,649	9.50	5,016
	148,642.15	61,343	57,688	90,954		15,702
	211,671.26	99,327	89,606	122,065		23,727

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1 11.21

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	385,091.78	346,583	334,923	50,169	0.50	50,169
2023	8,449,684.03	5,914,779	5,715,787	2,733,897	1.50	1,822,598
2024	105,727.22	52,864	51,085	54,642	2.50	21,857
2025	2,608,891.49	782,667	756,336	1,852,556	3.50	529,302
2026	2,467,186.26	246,719	238,419	2,228,768	4.50	495,282
	14,016,580.78	7,343,612	7,096,550	6,920,031		2,919,208
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					2.4	20.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.41 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	49,440.00	46,968	49,440			
2019	985,498.08	739,124	817,233	168,265	2.50	67,306
2020	17,620.50	11,453	12,663	4,957	3.50	1,416
2021	44,109.42	24,260	26,824	17,286	4.50	3,841
2022	240,887.73	108,399	119,854	121,033	5.50	22,006
2023	1,660,917.30	581,321	642,754	1,018,163	6.50	156,640
2024	2,425,842.93	606,461	670,551	1,755,292	7.50	234,039
2025	22,628.43	3,394	3,753	18,876	8.50	2,221
	5,446,944.39	2,121,380	2,343,072	3,103,872		487,469

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4 8.95

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.42 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	365,169.50	352,998	357,656	7,514	0.50	7,514
2013	142,364.69	128,128	129,819	12,546	1.50	8,364
2014	495,556.48	412,962	418,411	77,146	2.50	30,858
2022	1,468,239.56	440,472	446,284	1,021,956	10.50	97,329
2023	33,630,977.05	7,847,116	7,950,655	25,680,322	11.50	2,233,071
2024	8,239,887.66	1,373,342	1,391,463	6,848,425	12.50	547,874
	44,342,194.94	10,555,018	10,694,286	33,647,909		2,925,010

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.5 6.60

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	794,926.72	572,029	720,521	74,406	2.53	29,409
2021	1,291,033.02	853,502	1,075,061	215,972	2.82	76,586
2022	422,631.37	245,126	308,758	113,874	3.26	34,931
2023	231,386.91	110,372	139,023	92,364	3.84	24,053
2024	218,051.69	77,452	97,558	120,494	4.54	26,541
	2,958,029.71	1,858,481	2,340,920	617,110		191,520
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	304,523.53	240,726	252,613	51,911	2.25	23,072
2020	137,856.36	99,201	104,099	33,757	2.53	13,343
2021	29,132.71	19,260	20,211	8,922	2.82	3,164
2022	136,054.57	78,912	82,809	53,246	3.26	16,333
2023	103,840.99	49,532	51,978	51,863	3.84	13,506
2024	72,933.86	25,906	27,185	45,749	4.54	10,077
2025	110,022.28	24,205	25,400	84,622	5.32	15,906
2026	134,000.29	10,023	10,518	123,482	6.18	19,981
	1,028,364.59	547,765	574,813	453,552		115,382
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2019	58,753.80	44,682	49,231	9,523	2.36	4,035
2020	78,115.18	56,212	61,935	16,181	2.53	6,396
2021	64,848.27	42,871	47,235	17,613	2.82	6,246
2023	32,141.55	15,332	16,893	15,249	3.84	3,971
2024	70,345.77	24,987	27,531	42,815	4.54	9,431
2026	357,364.15	26,731	29,452	327,912	6.18	53,060
	661,568.72	210,815	232,277	429,292		83,139
	4,647,963.02	2,617,061	3,148,010	1,499,954		390,041

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.8 8.39

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	206,697.03	162,547	178,623	28,074	2.85	9,851
2018	1,391,827.54	1,019,792	1,120,648	271,180	3.10	87,477
2019	535,513.16	371,111	407,813	127,700	3.32	38,464
2020	3,018,536.19	1,930,656	2,121,595	896,942	3.66	245,066
2021	750,652.30	428,547	470,930	279,723	4.13	67,730
2022	1,578,781.13	770,761	846,988	731,793	4.72	155,041
2023	2,378,819.12	935,827	1,028,379	1,350,440	5.40	250,081
2024	3,960,987.23	1,145,518	1,258,808	2,702,179	6.14	440,094
2025	3,139,598.54	556,651	611,703	2,527,896	6.96	363,203
2026	4,070,364.05	243,408	267,481	3,802,883	7.85	484,444
	21,031,776.29	7,564,818	8,312,966	12,718,810		2,141,451
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	840,756.62	661,171	677,166	163,591	2.85	57,400
2018	613,979.49	449,863	460,746	153,233	3.10	49,430
2019	1,702,432.05	1,179,785	1,208,326	494,106	3.32	148,827
2020	2,660,378.22	1,701,578	1,742,742	917,636	3.66	250,720
2021	988,999.52	564,620	578,279	410,720	4.13	99,448
2022	1,715,459.97	837,488	857,748	857,712	4.72	181,719
2023	1,442,903.01	567,638	581,370	861,533	5.40	159,543
2024	2,005,431.93	579,971	594,002	1,411,430	6.14	229,875
2025	1,998,270.66	354,293	362,864	1,635,407	6.96	234,972
2026	1,360,133.21	81,336	83,304	1,276,830	7.85	162,654
	15,328,744.68	6,977,743	7,146,548	8,182,197		1,574,588
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2019	1,355,363.22	939,267	1,071,371	283,992	3.32	85,540
2020	2,003,353.34	1,281,345	1,461,561	541,792	3.66	148,031
2021	1,739,612.08	993,145	1,132,827	606,785	4.13	146,921
2022	1,522,755.39	743,409	847,967	674,789	4.72	142,964
2023	592,754.09	233,189	265,986	326,768	5.40	60,513

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2024	636,195.54	183,988	209,865	426,330	6.14	69,435
2025	1,524,658.17	270,322	308,342	1,216,316	6.96	174,758
2026	5,105,975.85	305,337	348,281	4,757,694	7.85	606,076
	14,480,667.68	4,950,002	5,646,200	8,834,468		1,434,238
	50,841,188.65	19,492,563	21,105,714	29,735,475		5,150,277
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.8	10.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	151,470.08	96,108	119,552	31,918	4.32	7,388
2020	1,825,853.39	1,038,545	1,291,883	533,971	4.93	108,311
2022	155,830.23	64,233	79,902	75,929	6.42	11,827
2025	415,782.24	58,792	73,133	342,649	9.10	37,654
	2,548,935.94	1,257,678	1,564,470	984,466		165,180
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	454,332.62	312,808	312,880	141,453	3.85	36,741
2020	770,171.79	438,074	438,175	331,997	4.93	67,342
2021	72,484.22	35,800	35,808	36,676	5.64	6,503
2022	225,437.99	92,926	92,947	132,491	6.42	20,637
2024	435,546.23	102,266	102,290	333,257	8.15	40,890
2025	145,862.66	20,625	20,630	125,233	9.10	13,762
2026	218,968.70	10,335	10,337	208,631	10.09	20,677
	2,322,804.21	1,012,834	1,013,067	1,309,737		206,552
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	571,135.22	362,385	392,884	178,252	4.32	41,262
2020	477,207.40	271,436	294,280	182,927	4.93	37,105
2021	159,371.81	78,714	85,339	74,033	5.64	13,126
2022	234,459.29	96,644	104,778	129,682	6.42	20,200
2023	171,839.19	55,934	60,641	111,198	7.25	15,338
2024	311,597.02	73,163	79,320	232,277	8.15	28,500
2025	273,740.09	38,707	41,965	231,775	9.10	25,470
2026	524,028.77	24,734	26,816	497,213	10.09	49,278
	2,723,378.79	1,001,717	1,086,022	1,637,357		230,279
	7,595,118.94	3,272,229	3,663,559	3,931,560		602,011

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 7.93

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	535,638.12	368,787	455,250	80,388	3.85	20,880
2019	381,787.38	242,244	299,039	82,749	4.32	19,155
2020	414,682.49	235,871	291,172	123,511	4.93	25,053
2021	310,179.53	153,198	189,116	121,064	5.64	21,465
2022	1,307,895.60	539,115	665,512	642,384	6.42	100,060
2023	547,886.82	178,337	220,149	327,738	7.25	45,205
2025	889,618.07	125,792	155,284	734,334	9.10	80,696
	4,387,688.01	1,843,344	2,275,521	2,112,167		312,514
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	407,965.65	280,884	280,100	127,866	3.85	33,212
2019	306,754.61	194,636	194,093	112,662	4.32	26,079
2020	341,279.16	194,120	193,578	147,701	4.93	29,960
2023	814,018.32	264,963	264,223	549,795	7.25	75,834
2025	813,570.98	115,039	114,718	698,853	9.10	76,797
2026	317,534.33	14,988	14,946	302,588	10.09	29,989
	3,001,123.05	1,064,630	1,061,658	1,939,465		271,871
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2002	64,657.75	62,718	64,658			
2005	234,486.07	220,229	234,486			
2019	301,872.38	191,538	212,599	89,274	4.32	20,665
2020	510,673.88	290,471	322,410	188,264	4.93	38,187
2023	267,890.81	87,198	96,786	171,105	7.25	23,601

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2024	1,374,619.01	322,761	358,250	1,016,369	8.15	124,708
2025	14,484.75	2,048	2,273	12,212	9.10	1,342
2026	856,457.41	40,425	44,870	811,587	10.09	80,435
	3,625,142.06	1,217,388	1,336,331	2,288,811		288,938
	11,013,953.12	4,125,362	4,673,510	6,340,443		873,323
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.3	7.93

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	16,490.72	12,266	15,829	662	4.99	133
2014	38,491.58	27,040	34,894	3,598	5.29	680
2016	325,609.19	211,646	273,121	52,488	5.65	9,290
2018	36,897.65	21,297	27,483	9,415	6.23	1,511
2019	26,522.13	14,083	18,174	8,349	6.62	1,261
2020	69,273.71	33,050	42,650	26,624	7.12	3,739
2021	21,143.06	8,815	11,375	9,768	7.69	1,270
2025	26,522.47	3,315	4,278	22,245	10.50	2,119
	560,950.51	331,512	427,803	133,148		20,003
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1998	6,033.11	5,539	5,555	478	2.52	190
2004	1,113.67	956	959	155	3.66	42
2010	43,130.65	33,521	33,620	9,511	4.73	2,011
2011	46,407.77	35,316	35,420	10,988	4.87	2,256
2018	75,946.02	43,836	43,965	31,981	6.23	5,133
2020	57,970.24	27,658	27,739	30,231	7.12	4,246
2021	77,135.14	32,158	32,253	44,883	7.69	5,837
2022	19,869.70	6,966	6,986	12,883	8.34	1,545
2023	69,514.19	19,436	19,493	50,021	9.02	5,546
2025	192,893.70	24,112	24,183	168,711	10.50	16,068
2026	84,538.66	3,559	3,569	80,969	11.38	7,115
	674,552.85	233,057	233,742	440,811		49,989
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1993	1,651.82	1,576	1,652			
2000	30,976.92	27,892	30,811	165	2.90	57
2001	5,792.76	5,163	5,703	89	3.08	29
2002	16,245.60	14,301	15,798	448	3.30	136
2003	15,284.09	13,291	14,682	602	3.49	172
2004	84,957.51	72,962	80,599	4,358	3.66	1,191
2005	97,134.57	82,156	90,755	6,379	3.87	1,648

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2006	19,722.25	16,415	18,133	1,589	4.08	389
2008	12,522.34	10,123	11,183	1,340	4.38	306
2010	8,864.62	6,890	7,611	1,253	4.73	265
2017	7,046.36	4,345	4,800	2,247	5.91	380
2019	69,224.39	36,758	40,606	28,619	6.62	4,323
2020	107,418.09	51,249	56,613	50,805	7.12	7,136
2021	239,940.91	100,031	110,501	129,440	7.69	16,832
2022	214,479.59	75,197	83,068	131,412	8.34	15,757
2024	201,759.41	41,260	45,579	156,181	9.72	16,068
2025	361,480.97	45,185	49,915	311,566	10.50	29,673
2026	202,315.77	8,517	9,408	192,907	11.38	16,951
	1,696,817.97	613,311	677,418	1,019,400		111,313
	2,932,321.33	1,177,880	1,338,963	1,593,359		181,305

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.8 6.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,589.99	3,494	3,494	2,096	7.50	279
2018	10,248.45	4,356	4,355	5,893	11.50	512
	15,838.44	7,850	7,849	7,989		791

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.1 4.99

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	637,237.38	613,341	630,345	6,892	0.75	6,892
2008	236,121.16	218,412	224,467	11,654	1.50	7,769
2009	314,488.38	275,177	282,806	31,682	2.50	12,673
2010	162,964.81	134,446	138,173	24,791	3.50	7,083
2011	451,363.00	349,806	359,504	91,859	4.50	20,413
2012	368,654.37	267,274	274,684	93,970	5.50	17,085
2013	792,113.30	534,676	549,500	242,614	6.50	37,325
2014	476,076.46	297,548	305,797	170,279	7.50	22,704
2015	1,648,297.12	947,771	974,047	674,250	8.50	79,324
2016	1,270,294.92	666,905	685,394	584,900	9.50	61,568
2017	1,830,420.92	869,450	893,555	936,866	10.50	89,225
2018	915,728.07	389,184	399,974	515,754	11.50	44,848
2019	1,013,925.51	380,222	390,763	623,162	12.50	49,853
2020	1,214,941.27	394,856	405,803	809,138	13.50	59,936
2021	2,421,094.90	665,801	684,260	1,736,835	14.50	119,782
2022	2,950,748.68	663,918	682,325	2,268,424	15.50	146,350
2023	2,303,400.56	403,095	414,271	1,889,130	16.50	114,493
2024	1,538,342.77	192,293	197,624	1,340,719	17.50	76,613
2025	1,186,024.58	88,952	91,418	1,094,606	18.50	59,168
2026	866,467.20	21,662	22,263	844,205	19.50	43,293
	22,598,705.36	8,374,789	8,606,974	13,991,731		1,076,397
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	397,958.98	383,036	389,609	8,350	0.75	8,350
2008	194,881.81	180,266	183,360	11,522	1.50	7,681
2009	386,652.36	338,321	344,127	42,525	2.50	17,010
2010	528,508.76	436,020	443,502	85,006	3.50	24,287
2011	46,412.17	35,969	36,586	9,826	4.50	2,184
2012	106,370.79	77,119	78,442	27,928	5.50	5,078
2013	245,409.98	165,652	168,495	76,915	6.50	11,833
2014	495,061.18	309,413	314,723	180,338	7.50	24,045
2015	960,119.93	552,069	561,543	398,577	8.50	46,891
2016	523,955.99	275,077	279,798	244,158	9.50	25,701
2017	608,859.13	289,208	294,171	314,688	10.50	29,970
2018	1,012,779.35	430,431	437,818	574,962	11.50	49,997
2019	553,146.33	207,430	210,990	342,157	12.50	27,373
2020	1,269,985.14	412,745	419,828	850,157	13.50	62,975

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,323,741.79	364,029	370,276	953,466	14.50	65,756
2022	786,517.05	176,966	180,003	606,514	15.50	39,130
2023	1,635,510.95	286,214	291,126	1,344,385	16.50	81,478
2024	938,712.15	117,339	119,353	819,360	17.50	46,821
2025	778,594.88	58,395	59,397	719,198	18.50	38,876
2026	488,309.08	12,208	12,417	475,892	19.50	24,405
	13,281,487.80	5,107,907	5,195,563	8,085,925		639,841
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	491,013.65	472,601	421,301	69,713	0.75	69,713
2008	601,711.46	556,583	496,167	105,545	1.50	70,363
2009	555,234.09	485,830	433,094	122,140	2.50	48,856
2010	130,973.00	108,053	96,324	34,649	3.50	9,900
2011	37,493.92	29,058	25,904	11,590	4.50	2,576
2012	293,686.51	212,923	189,811	103,876	5.50	18,887
2013	299,610.27	202,237	180,285	119,326	6.50	18,358
2014	509,913.33	318,696	284,102	225,811	7.50	30,108
2015	265,009.96	152,381	135,840	129,170	8.50	15,196
2016	645,329.65	338,798	302,022	343,308	9.50	36,138
2017	190,998.54	90,724	80,876	110,122	10.50	10,488
2018	723,680.35	307,564	274,178	449,502	11.50	39,087
2019	612,456.17	229,671	204,741	407,716	12.50	32,617
2020	522,174.71	169,707	151,286	370,889	13.50	27,473
2021	1,106,649.73	304,329	271,295	835,355	14.50	57,611
2022	842,166.59	189,487	168,919	673,248	15.50	43,435
2023	351,898.78	61,582	54,897	297,001	16.50	18,000
2024	213,446.62	26,681	23,785	189,662	17.50	10,838
2025	658,104.88	49,358	44,000	614,105	18.50	33,195
2026	479,218.69	11,980	10,680	468,539	19.50	24,028
	9,530,770.90	4,318,243	3,849,505	5,681,266		616,867
	45,410,964.06	17,800,939	17,652,042	27,758,922		2,333,105

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.9 5.14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	318	309	244	8.50	29
2016	295.77	155	151	145	9.50	15
2017	411,182.60	195,312	189,834	221,348	10.50	21,081
2018	25,747.54	10,943	10,636	15,111	11.50	1,314
	437,778.64	206,728	200,930	236,849		22,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6 5.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,748	6,030	468	3.42	137
2001	27,339.91	23,884	25,057	2,283	3.65	625
2002	3,719.59	3,211	3,369	351	3.84	91
2003	30,828.76	26,306	27,598	3,231	4.00	808
2004	11,906.59	10,013	10,505	1,402	4.21	333
2005	9,418.96	7,806	8,189	1,230	4.39	280
2006	22,392.50	18,275	19,172	3,220	4.56	706
2007	37,931.66	30,376	31,867	6,064	4.79	1,266
2009	17,602.56	13,646	14,316	3,287	5.07	648
2013	15,373.86	10,854	11,387	3,987	5.62	709
2018	220,480.47	122,014	128,005	92,476	6.86	13,480
2019	308,929.87	156,380	164,058	144,872	7.32	19,791
2020	2,155,616.89	978,003	1,026,020	1,129,597	7.83	144,265
2021	384,329.95	151,580	159,022	225,308	8.45	26,664
2022	684,283.11	226,635	237,762	446,521	9.09	49,122
2023	216,868.00	57,166	59,973	156,895	9.78	16,042
2024	255,991.05	49,201	51,617	204,374	10.50	19,464
2025	755,399.83	88,608	92,958	662,441	11.29	58,675
	5,164,911.92	1,979,706	2,076,904	3,088,008		353,106
PNG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	58,118	68,110			
2004	167,248.57	140,656	167,249			
2007	13,369.18	10,706	12,876	493	4.79	103
2008	35,075.31	27,709	33,326	1,750	4.92	356
2009	48,114.46	37,298	44,859	3,256	5.07	642
2010	12,089.03	9,195	11,059	1,030	5.19	198
2016	8,023.37	5,038	6,059	1,964	6.22	316
2018	1,346,981.57	745,420	896,521	450,461	6.86	65,665
2020	1,330,094.12	603,464	725,790	604,305	7.83	77,178
2021	407,333.02	160,652	193,217	214,116	8.45	25,339
2022	764,277.51	253,129	304,440	459,838	9.09	50,587
2024	118,030.40	22,685	27,283	90,747	10.50	8,643
2025	305,022.18	35,779	43,032	261,991	11.29	23,206
	4,623,768.46	2,109,849	2,533,819	2,089,949		252,233

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2001	29,034.66	25,365	26,140	2,895	3.65	793
2003	58,019.67	49,508	51,021	6,999	4.00	1,750
2004	98,699.95	83,007	85,543	13,157	4.21	3,125
2005	80,413.99	66,647	68,683	11,731	4.39	2,672
2006	32,646.90	26,643	27,457	5,190	4.56	1,138
2008	69,039.30	54,541	56,208	12,832	4.92	2,608
2019	106,125.88	53,721	55,362	50,763	7.32	6,935
2020	920,993.58	417,855	430,623	490,371	7.83	62,627
2021	727,173.36	286,797	295,560	431,613	8.45	51,078
2022	603,777.04	199,971	206,081	397,696	9.09	43,751
2023	338,548.00	89,241	91,968	246,580	9.78	25,213
2024	162,408.89	31,215	32,169	130,240	10.50	12,404
2025	366,261.18	42,962	44,275	321,986	11.29	28,520
2026	416,339.73	16,445	16,947	399,392	12.16	32,845
	4,009,482.13	1,443,918	1,488,037	2,521,445		275,459
	13,798,162.51	5,533,473	6,098,760	7,699,402		880,798

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.7 6.38

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	67,288.99	37,009	35,359	31,930	4.50	7,096
2023	23,301.32	8,155	7,791	15,510	6.50	2,386
2024	328,750.94	82,188	78,523	250,228	7.50	33,364
2025	102,352.01	15,353	14,668	87,684	8.50	10,316
	521,693.26	142,705	136,341	385,352		53,162
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	713,351.62	677,684	641,361	71,991	0.50	71,991
2019	33,841.70	25,381	24,021	9,821	2.50	3,928
2020	50,424.62	32,776	31,019	19,405	3.50	5,544
2021	75,819.30	41,701	39,466	36,353	4.50	8,078
2022	80,244.45	36,110	34,175	46,070	5.50	8,376
2023	99,558.60	34,846	32,978	66,580	6.50	10,243
2025	208,029.43	31,204	29,532	178,498	8.50	21,000
	1,261,269.72	879,702	832,551	428,719		129,160
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	17,961.49	17,063	13,814	4,147	0.50	4,147
2020	45,131.19	29,335	23,749	21,382	3.50	6,109
2021	21,890.53	12,040	9,748	12,143	4.50	2,698
2022	73,558.62	33,101	26,798	46,760	5.50	8,502
2024	407,805.20	101,951	82,539	325,266	7.50	43,369
2025	746,140.09	111,921	90,611	655,529	8.50	77,121
	1,312,487.12	305,411	247,259	1,065,228		141,946
	3,095,450.10	1,327,818	1,216,151	1,879,299		324,268

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.8 10.48

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	102,456.20	99,041	102,456			
2013	68,350.42	61,515	68,350			
2014	140,132.49	116,777	140,132			
2015	39,471.49	30,262	37,708	1,764	3.50	504
2016	32,235.43	22,565	28,117	4,119	4.50	915
2017	165,977.94	105,119	130,982	34,996	5.50	6,363
2018	8,884.33	5,034	6,273	2,612	6.50	402
2020	89,054.88	38,590	48,085	40,970	8.50	4,820
2024	3,226.50	538	670	2,556	12.50	204
2026	138,749.73	4,625	5,763	132,987	14.50	9,172
	788,539.41	484,066	568,536	220,003		22,380
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	6,969.59	6,737	6,970			
2014	262,109.02	218,423	262,109			
2016	44,259.57	30,982	44,260			
2017	64,069.97	40,577	64,070			
2018	1,869.95	1,060	1,870			
2020	61,699.27	26,736	54,976	6,723	8.50	791
2022	43,216.83	12,965	26,659	16,557	10.50	1,577
2023	41,520.68	9,688	19,921	21,600	11.50	1,878
2024	35,482.97	5,914	12,161	23,322	12.50	1,866
2025	15,929.11	1,593	3,276	12,653	13.50	937
2026	139,058.27	4,635	9,531	129,527	14.50	8,933
	716,185.23	359,310	505,802	210,383		15,982
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	14,758.99	14,267	14,759			
2013	2,414.03	2,173	2,414			
2015	4,085.64	3,132	4,086			
2017	81,771.73	51,788	69,036	12,735	5.50	2,315
2018	4,477.95	2,538	3,383	1,095	6.50	168

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	5,471.06	2,736	3,647	1,824	7.50	243
2022	30,914.09	9,274	12,363	18,551	10.50	1,767
2023	42,498.56	9,916	13,219	29,280	11.50	2,546
2026	245,853.70	8,194	10,923	234,931	14.50	16,202
	432,245.75	104,018	133,830	298,416		23,241
	1,936,970.39	947,394	1,208,168	728,802		61,603

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8 3.18

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING - DENVER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 1-2069						
NET SALVAGE PERCENT.. 0						
2019	29,987,923.48	5,712,699	6,016,098	23,971,825	31.87	752,175
2020	1,918,595.10	326,737	344,090	1,574,505	31.67	49,716
2021	647,293.08	96,447	101,569	545,724	31.40	17,380
2022	2,012,444.98	255,379	268,942	1,743,503	30.96	56,315
2023	104,904.91	10,795	11,368	93,537	30.51	3,066
2024	34,006.49	2,636	2,776	31,230	29.76	1,049
2025	56,251.31	2,813	2,962	53,289	28.53	1,868
2026	354,752.12	6,847	7,211	347,541	25.41	13,677
	35,116,171.47	6,414,353	6,755,017	28,361,154		895,246
READING DATA CENTER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2073						
NET SALVAGE PERCENT.. 0						
2023	11,744,977.98	1,146,310	1,207,190	10,537,788	32.34	325,844
2024	8,669,490.58	639,808	673,788	7,995,703	31.40	254,640
	20,414,468.56	1,786,118	1,880,978	18,533,491		580,484
KNITTING MILLS OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. 0						
2022	1,382,240.38	248,250	261,435	1,120,805	20.56	54,514
	1,382,240.38	248,250	261,435	1,120,805		54,514
	56,912,880.41	8,448,721	8,897,430	48,015,450		1,530,244

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.4 2.69

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	3,525,373.71	1,322,015	1,255,487	2,269,887	12.50	181,591
2020	39,198.12	12,739	12,098	27,100	13.50	2,007
2021	10,994.97	3,024	2,872	8,123	14.50	560
2022	823,953.90	185,390	176,060	647,894	15.50	41,800
2024	1,250.26	156	148	1,102	17.50	63
2025	475,773.40	35,683	33,888	441,885	18.50	23,886
2026	50,000.00	1,250	1,187	48,813	19.50	2,503
	4,926,544.36	1,560,257	1,481,740	3,444,804		252,410

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.6 5.12

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	2,352,543.96	2,117,290	2,065,791	286,753	0.50	286,753
2023	4,553,142.98	3,187,200	3,109,677	1,443,466	1.50	962,311
2024	6,182,441.02	3,091,221	3,016,033	3,166,408	2.50	1,266,563
2025	4,789,195.97	1,436,759	1,401,812	3,387,384	3.50	967,824
	17,877,323.93	9,832,470	9,593,313	8,284,011		3,483,451

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.4 19.49

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2024						
NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,803,866	2,803,866			
	2,803,866.07	2,803,866	2,803,866			
UNITE ERP						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2034						
NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	5,175,385	4,583,616	6,112,200	8.00	764,025
	10,695,816.43	5,175,385	4,583,616	6,112,200		764,025
	13,499,682.50	7,979,251	7,387,482	6,112,200		764,025
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.0	5.66

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	2,045,175.15	1,942,916	1,944,017	101,158	0.50	101,158
2018	1,342,824.54	1,141,401	1,142,048	200,777	1.50	133,851
2019	5,856,940.93	4,392,706	4,395,196	1,461,745	2.50	584,698
2020	12,398,870.46	8,059,266	8,063,834	4,335,036	3.50	1,238,582
2021	7,484,201.44	4,116,311	4,118,644	3,365,557	4.50	747,902
2022	8,108,350.38	3,648,758	3,650,827	4,457,523	5.50	810,459
2023	4,635,166.80	1,622,308	1,623,228	3,011,939	6.50	463,375
2024	3,642,835.09	910,709	911,225	2,731,610	7.50	364,215
2025	4,367,835.83	655,175	655,546	3,712,290	8.50	436,740
2026	48,545,652.15	2,427,283	2,428,659	46,116,993	9.50	4,854,420
	98,427,852.77	28,916,833	28,933,224	69,494,629		9,735,400

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1 9.89

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2026

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	1,993,990.05	1,395,793	1,373,263	620,727	4.50	137,939
2017	75,949,954.16	48,101,384	47,324,954	28,625,000	5.50	5,204,545
2018	171,214.09	97,022	95,456	75,758	6.50	11,655
2019	43,488,813.59	21,744,407	21,393,419	22,095,395	7.50	2,946,053
2021	7,013,315.14	2,571,572	2,530,063	4,483,252	9.50	471,921
2022	1,548,319.97	464,496	456,998	1,091,322	10.50	103,935
2023	2,728,425.32	636,623	626,347	2,102,078	11.50	182,789
2024	871,670.44	145,281	142,936	728,734	12.50	58,299
2025	267,380.05	26,738	26,307	241,073	13.50	17,857
	134,033,082.81	75,183,316	73,969,743	60,063,340		9,134,993

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.6 6.82

PART VIII. EXPERIENCED AND ESTIMATED NET SALVAGE

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
367.00		463.82		463.82-
369.00		4,906.28		4,906.28-
375.00		345.87		345.87-
376.10	2,225,032.94	749,916.61		749,916.61-
376.20	213,665.66	270,874.29		270,874.29-
376.30	3,569,860.81	1,130,258.76		1,130,258.76-
376.50	99.53			
378.00	412,657.26	278,820.57		278,820.57-
379.00	144,233.30	98,843.74		98,843.74-
380.00	12,730,509.62	4,547,450.60		4,547,450.60-
381.00	1,556,577.90	711.28		711.28-
382.00	1,859,075.73	164,128.06		164,128.06-
384.00	719,951.43	2,202.00		2,202.00-
385.00		154.19-		154.19
390.10		969.10		969.10-
391.00	6,694.08			
391.10	136,398.30			
391.20	6,467.49			
391.30	347,005.99			
391.92	165,870.51			
392.00	929,504.65			
392.20			1,548,910.16	1,548,910.16
394.00	684,358.29	21,727.71		21,727.71-
396.00	142,855.69			
397.00	82,937.84			
398.00	143,551.53	150,544.57		150,544.57-
	26,077,308.55	7,422,009.07	1,548,910.16	5,873,098.91-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2023 TRANSACTION YEAR				
325.10	9,986.53			
325.20	35,825.88			
328.00	1,263.20			
329.00	44,784.66			
330.00	18,208.60			
331.00	24,440.72			
332.00	308,348.25			
334.00	89,724.69			
335.00	49,603.72			
337.00	11,062.15			
367.00	13.90	411.88		411.88-
369.00		231.13		231.13-
375.00	4,361.80	1,876.12		1,876.12-
376.10	1,911,104.74	1,693,881.68		1,693,881.68-
376.20	231,008.33	633,299.14		633,299.14-
376.30	3,015,781.26	311,402.09		311,402.09-
376.50	147.85			
378.00	125,958.48	206,791.94		206,791.94-
379.00	87,005.59	85,311.85		85,311.85-
380.00	14,014,376.89	5,345,562.48		5,345,562.48-
381.00	1,365,599.25	35,495.28		35,495.28-
381.10	1,591,780.95	2,076.27		2,076.27-
382.00	147,042.47	117,423.95		117,423.95-
383.00		805.84		805.84-
384.00	73,967.50	82.38		82.38-
390.10	2,990,794.20	395.27		395.27-
392.00	363,110.57			
392.20			887,269.86	887,269.86
394.00		167.21		167.21-
397.00		11.22		11.22-
398.00		79,441.38		79,441.38-
	26,515,302.18	8,514,667.11	887,269.86	7,627,397.25-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2024 TRANSACTION YEAR				
367.00	15,789.19-	5,800.82		5,800.82-
375.00		.25		.25-
376.10	3,278,709.32	1,190,708.39		1,190,708.39-
376.20	340,704.97	682,407.68		682,407.68-
376.30	3,202,277.34	819,607.41		819,607.41-
376.50	9.47			
378.00	1,310.54	165,132.29		165,132.29-
379.00		43,038.20		43,038.20-
380.00	11,321,460.10	4,613,723.58		4,613,723.58-
381.00	1,560,893.83	48,410.73		48,410.73-
381.10		9,684.81		9,684.81-
382.00	168,066.15	65,380.33		65,380.33-
383.00		3,328,106.96		3,328,106.96-
384.00	56,498.06	281.79		281.79-
385.00		984.10		984.10-
386.10		207.86		207.86-
390.10	3,960,071.14	552,199.64		552,199.64-
391.00	28,382.78			
391.10	10,004,713.85			
391.20	1,637.58			
391.30	6,310,627.32			
392.00	22,224.80			
392.20			645,657.43	645,657.43
393.00	1,768.11			
394.00	1,697,038.69			
397.00	31,989.83	2,888.76		2,888.76-
398.00	139,478.08	74,235.76		74,235.76-
	42,112,072.77	11,602,799.36	645,657.43	10,957,141.93-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2025 TRANSACTION YEAR				
367.00		9,570.67		9,570.67-
375.00		12,062.12		12,062.12-
376.10		2,102,594.83		2,102,594.83-
376.20		899,143.51		899,143.51-
376.30		508,772.12		508,772.12-
378.00		313,280.97		313,280.97-
379.00		196,337.52		196,337.52-
380.00		5,022,669.19		5,022,669.19-
381.00		74,865.17		74,865.17-
381.10		18,782.17		18,782.17-
382.00		94,529.64		94,529.64-
383.00		1,028,703.39		1,028,703.39-
384.00		2,577.96		2,577.96-
385.00		87,207.33		87,207.33-
386.00		774.21		774.21-
386.10		1,025.40		1,025.40-
390.10		105,143.54		105,143.54-
392.20			749,272.22	749,272.22
397.00		9,703.27		9,703.27-
398.00		86,622.06		86,622.06-
		10,574,365.07	749,272.22	9,825,092.85-
2026 TRANSACTION YEAR				
375.00		7,249.59		7,249.59-
376.10		1,182,057.76		1,182,057.76-
376.30		757,434.79		757,434.79-
378.00		53,422.45		53,422.45-
380.00		7,271,309.73		7,271,309.73-
382.00		341,280.10		341,280.10-
385.00		326,137.90-		326,137.90
390.10		30,951.26		30,951.26-
392.10			4,546.90	4,546.90
392.20			86,856.48	86,856.48
392.30			7,429.97	7,429.97
392.40			10,774.47	10,774.47
392.50			2,868.56	2,868.56
		9,317,567.78	112,476.38	9,205,091.40-
TOTAL	94,704,683.50	47,431,408.39	3,943,586.05	43,487,822.34-

BOOK VIII

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C
(HISTORIC)
2025 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF SEPTEMBER 30, 2025

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI Gas Exhibit C (Historic)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2025

Prepared by:

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT SEPTEMBER 30, 2025

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming Valuation and Rate Consultants, LLC
(a GFT Company)

300 Sterling Parkway, Suite 200
Mechanicsburg, PA 17050
717.763.7211

January 14, 2026

Jessica R. Rogers
Vice President – Rates and Regulatory Affairs
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant at September 30, 2025 for the consolidated UGI gas company. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 and 2 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Gas Exhibit C (Future), "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2026".

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

JOHN F. WIEDMAYER, C.D.P.
Senior Project Manager - Depreciation Studies

085304.100

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PART I. INTRODUCTION

UGI UTILITIES, INC. – GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. – Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2025.

BASIS OF STUDY

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2025, are set forth in Table 1 and are based on data through 2022 for the consolidated UGI gas company. The service life estimates are the same estimates as submitted to the Pennsylvania Public Utility Commission (PA PUC) in the most recent service life study report in May 2023.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2025, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2025, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 and 2 presented on pages II-3 through II-7 summarize the results of the depreciation study as of September 30, 2025 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve as of September 30, 2025, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the annual amortization of experienced net salvage based on the period 2021 through 2025.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 2 which presents the five-year amortization.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2025

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION			-	23,039	(23,039)	-	-
329	OTHER STRUCTURES			-	-	-	-	-
332	FIELD LINES			-	-	-	-	-
335	DRILLING AND CLEANING EQUIPMENT			-	-	-	-	-
TOTAL PRODUCTION PLANT				**-**	**23,039**	**(23,039)**	**-**	**-**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	571,904	296,256	1.31	11,331
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	156,695	5,521	0.18	295
367	MAINS		75 - R2.5	39,468,181	23,115,954	16,352,227	1.03	407,659
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2.5	6,172,834	4,255,146	1,917,688	1.47	90,682
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,505,204	2,462,642	1,042,562	2.47	86,448
371	OTHER EQUIPMENT		35 - R2.5	140,637	133,053	7,584	0.67	944
371.1	TESTING EQUIPMENT		20 - R3	210,011	167,850	42,161	2.18	4,573
TOTAL TRANSMISSION PLANT				**50,527,243**	**30,863,244**	**19,663,999**	**1.19**	**601,932**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,374,004	1,508,064	1,865,940	1.28	43,210
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	7,180,945	3,577,081	3,603,864	1.80	129,180
376.1	MAINS - PRIMARILY STEEL		75 - R2.5	761,490,737	202,628,288	558,862,449	1.52	11,571,103
376.2	MAINS - CAST IRON	09-2027	65 - R1	664,766	605,269	59,497	4.64	30,836
376.3	MAINS - PLASTIC		68 - R3	1,988,393,622	359,244,271	1,629,149,351	1.64	32,642,348
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	305,201	255,480	49,721	1.82	5,553
376.7	REG AFUDC		40 - SQ	1,322,088	267,172	1,054,916	2.50	33,052
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		48 - S0	164,220,812	41,528,725	122,692,087	2.65	4,357,618
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R1.5	81,779,825	13,438,274	68,341,551	3.06	2,505,535
380	SERVICES		45 - R2	1,684,480,735	460,225,389	1,224,255,346	2.64	44,479,781
381	METERS		36 - R2	152,199,760	64,992,744	87,207,016	2.70	4,103,462
381.1	METERS - ERTS		17 - S3	40,639,561	17,039,782	23,599,779	7.45	3,028,398
382	METER INSTALLATIONS		45 - R2	141,911,982	47,684,946	94,227,036	2.41	3,417,739
383	HOUSE REGULATORS		45 - R2	10,274,123	3,921,107	6,353,016	3.32	340,722
384	HOUSE REGULATOR INSTALLATIONS		45 - R2	17,829,357	9,463,445	8,365,912	1.87	333,968
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	40,449,313	19,978,680	20,470,633	1.97	798,803
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		45 - R2	267,063	(55,879)	322,942	5.87	15,687
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R1.5	982,535	706,337	276,198	1.40	13,716
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,720	(15)	-	-
387	OTHER EQUIPMENT		40 - R2.5	5,308,206	3,225,607	2,082,599	1.71	90,977
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,481,718	8,946	0.23	3,408
TOTAL DISTRIBUTION PLANT				**5,104,590,004**	**1,251,741,220**	**3,852,848,784**	**2.11**	**107,945,096**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS*	159,009,347	49,470,174	109,539,174	3.80	6,044,845
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY			-	-	-	-	-
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,762,063	1,973,088	3,788,975	5.55	320,037
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	209,716	122,642	87,074	9.14	19,163
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	11,611,467	4,391,081	7,220,386	21.56	2,503,732
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE		10 - SQ	4,378,298	4,333,192	45,106	-	-
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	7,187,173	3,667,639	3,519,534	6.58	472,629
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	52,700,181	16,378,755	36,321,426	5.51	2,905,396
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,238,742	2,777,810	1,460,932	9.14	387,289
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	43,024,106	18,137,557	24,886,549	9.87	4,245,367
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLE		12 - L3	6,926,421	3,144,919	3,781,502	8.04	556,799
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	10,044,251	3,935,541	6,108,710	7.92	795,406
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,674,151	1,191,005	1,483,146	6.17	165,046
393	STORES EQUIPMENT		20 - SQ	15,838	7,057	8,781	5.00	792
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	44,808,230	16,560,440	28,247,790	5.14	2,304,165
395	LABORATORY EQUIPMENT		20 - SQ	437,779	178,472	259,307	5.13	22,440
396	POWER OPERATED EQUIPMENT		16 - L2	13,798,162	5,174,132	8,624,030	6.70	925,056
397	COMMUNICATION EQUIPMENT		10 - SQ	3,095,450	825,767	2,269,683	12.53	387,935
398	MISCELLANEOUS EQUIPMENT		15 - SQ	1,510,050	1,055,236	454,814	5.50	83,112
399	OTHER TANGIBLE PROPERTY			16,032	16,032	-	-	-
TOTAL GENERAL PLANT				**371,447,457**	**133,340,539**	**238,106,919**	**5.96**	**22,139,209**
TOTAL DEPRECIABLE GAS PLANT				**5,526,564,704**	**1,415,968,042**	**4,110,596,663**	**2.36**	**130,686,237**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2025

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
NONDEPRECIABLE PLANT							
301 ORGANIZATION			166,478				
302 FRANCHISES AND CONSENTS			193,597				
303 MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1 LAND AND LAND RIGHTS - LAND			-				
304.2 LAND AND LAND RIGHTS - LAND RIGHTS			-				
325.1 PRODUCING LANDS			-				
325.5 OTHER LAND			-				
365.1 LAND			47,323				
374.1 LAND AND LAND RIGHTS - LAND			803,858				
374.2 LAND AND LAND RIGHTS - LAND RIGHTS			7,459,999				
389.1 LAND AND LAND RIGHTS - LAND			7,330,889				
389.2 LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT			**16,293,325**				
TOTAL GAS PLANT			**5,542,858,029**				
OTHER UTILITY PLANT							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS							
UGI HEADQUARTERS BUILDING - DENVER	01-2069	70 - R1	34,761,419	5,809,287	28,952,132	2.60	905,488
READING DATA CENTER	09-2073	70 - R1	20,414,469	1,306,157	19,108,312	3.01	613,820
KNITTING MILLS OFFICE	06-2050	70 - R1	1,382,240	203,120	1,179,120	4.05	55,962
TOTAL ACCOUNT 390.1			*56,558,128*	*7,318,564*	*49,239,564*	*2.79*	*1,575,270*
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,876,544	1,407,352	3,469,192	4.86	237,161
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,076,376	748,671	327,705	30.45	327,705
TOTAL COMMON PLANT			**69,597,120**	**9,474,587**	**53,036,461**	**3.42**	**2,140,136**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%			**62,017,994**	**8,442,804**	**47,260,790**		**1,907,075**
INFORMATION SERVICES (IS)							
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,877,324	5,819,410	12,057,914	21.11	3,773,588
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE							
SUCCESS FACTORS	09-2024	SQUARE	2,803,866	2,803,866	-	-	-
UNITE ERP	09-2034	SQUARE	10,695,816	3,819,935	6,875,881	7.14	763,987
TOTAL ACCOUNT 391.2			*13,499,682*	*6,623,801*	*6,875,881*	*5.66*	*763,987*
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	63,317,686	35,342,141	27,975,545	7.64	4,838,371
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,581,308	65,398,509	69,182,799	6.79	9,131,645
TOTAL INFORMATION SERVICES			**229,276,000**	**113,183,861**	**116,092,139**	**8.07**	**18,507,591**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%			**194,471,903**	**96,002,551**	**98,469,352**		**15,698,139**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS			12,568,452	8,652,881	3,915,571	1.57	197,050
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,642,697**	**1,130,932**	**511,765**		**25,754**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**254,847,200**	**103,314,423**	**145,218,377**		**17,579,460**
TOTAL PLANT IN SERVICE			**5,797,705,229**	**1,519,282,465**	**4,255,815,040**		**148,265,697**
AMORTIZATION OF NEGATIVE NET SALVAGE							**8,240,620**
GRAND TOTAL			**5,797,705,229**	**1,519,282,465**	**4,255,815,040**		**156,506,317**

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

ACCOUNT	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	(115,195)	0	0	0	0	0	0	0	0	0	(115,195)	(23,039)
329	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
335	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**(115,195)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(115,195)**	**(23,039)**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	1,660	0	464	0	412	0	5,801	0	9,571	17,907	3,581
369	0	3,386	0	4,906	0	231	0	0	0	0	8,523	1,705
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**5,046**	**0**	**5,370**	**0**	**643**	**0**	**5,801**	**0**	**9,571**	**26,431**	**5,286**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	0	0	346	0	1,876	0	0	0	12,062	14,284	2,857
376.1	0	1,712,927	0	749,917	0	1,693,882	0	1,190,708	0	2,102,595	7,450,029	1,490,006
376.2	0	92,247	0	270,874	0	633,299	0	682,408	0	899,144	2,577,972	515,594
376.3	0	728,986	0	1,130,259	0	311,402	0	819,607	0	508,772	3,499,026	699,805
376.5	0	0	0	0	0	0	0	0	0	0	0	0
378	0	168,692	0	278,821	0	206,792	0	165,132	0	313,281	1,132,718	226,544
379	0	15,105	0	98,844	0	85,312	0	43,038	0	196,338	438,636	87,727
380	0	4,191,361	0	4,547,451	0	5,345,562	0	4,613,724	0	5,022,669	23,720,767	4,744,153
381	(19,201)	1,237	0	711	0	35,495	0	48,411	0	74,865	141,518	28,304
381.1	0	0	0	0	0	2,076	0	9,685	0	18,782	30,543	6,109
382	0	224,823	0	164,128	0	117,424	0	65,380	0	94,530	666,285	133,257
383	0	269	0	0	0	806	0	3,328,107	0	1,028,703	4,357,885	871,577
384	0	13,720	0	2,202	0	82	0	282	0	2,578	18,864	3,773
385	0	35,290	0	(154)	0	0	0	984	0	87,207	123,327	24,665
386.0	0	0	0	0	0	0	0	0	0	774	774	155
386.1	0	0	0	0	0	0	0	208	0	1,025	1,233	247
386.2	0	0	0	0	0	0	0	0	0	0	0	0
386.3	0	0	0	0	0	0	0	0	0	0	0	0
387	0	0	0	0	0	0	0	0	0	0	0	0
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**(19,201)**	**7,184,657**	**0**	**7,243,398**	**0**	**8,434,009**	**0**	**10,967,674**	**0**	**10,363,326**	**44,173,863**	**8,834,773**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

ACCOUNT	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	2025 GROSS SALVAGE	2025 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	135	0	969	0	395	0	552,200	0	105,144	658,843	131,769
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
392.2	(526,894)	0	(1,548,910)	0	(887,270)	0	(645,657)	0	(749,272)	0	(4,358,004)	(871,601)
392.3	0	0	0	0	0	0	0	0	0	0	0	0
392.4	0	0	0	0	0	0	0	0	0	0	0	0
392.5	0	0	0	0	0	0	0	0	0	0	0	0
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	21,728	0	167	0	0	0	0	21,895	4,379
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	0	0	11	0	2,889	0	9,703	12,603	2,521
398	0	391,820	0	150,545	0	79,441	0	74,236	0	86,622	782,664	156,533
TOTAL	**(526,894)**	**391,955**	**(1,548,910)**	**173,241**	**(887,270)**	**80,015**	**(645,657)**	**629,324**	**(749,272)**	**201,469**	**(2,881,999)**	**(576,400)**
TOTAL GAS PLANT	**(661,290)**	**7,581,658**	**(1,548,910)**	**7,422,009**	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**41,203,099**	**8,240,620**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(661,290)**	**7,581,658**	**(1,548,910)**	**7,422,009**	**(887,270)**	**8,514,667**	**(645,657)**	**11,602,799**	**(749,272)**	**10,574,365**	**41,203,099**	**8,240,620**

* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1900	71,237	71,237			0.0
1901	5,184	4,859	325	325	0.0
1902	35,079	34,886	193	518	0.0
1903	43,148	42,757	391	909	0.0
1904	13,711	12,691	1,020	1,929	0.0
1905	8,837	8,063	774	2,703	0.0
1906	19,177	18,110	1,067	3,770	0.0
1907	26,246	24,737	1,509	5,279	0.0
1908	37,743	35,123	2,620	7,899	0.0
1909	10,033	8,949	1,084	8,983	0.0
1910	27,828	26,243	1,585	10,568	0.0
1911	37,310	34,093	3,217	13,785	0.0
1912	27,002	24,268	2,734	16,519	0.0
1913	26,451	23,300	3,151	19,670	0.0
1914	61,358	53,308	8,050	27,720	0.0
1915	34,026	29,637	4,389	32,109	0.0
1916	23,198	20,041	3,157	35,266	0.0
1917	16,749	16,009	740	36,006	0.0
1918	19,585	17,152	2,433	38,439	0.0
1919	18,719	17,532	1,187	39,626	0.0
1920	23,170	21,315	1,855	41,481	0.0
1921	72,339	66,517	5,822	47,303	0.0
1922	98,453	89,771	8,682	55,985	0.0
1923	86,521	78,697	7,824	63,809	0.0
1924	315,417	283,890	31,527	95,336	0.0
1925	112,620	104,165	8,455	103,791	0.0
1926	408,750	358,778	49,972	153,763	0.0
1927	135,580	126,618	8,962	162,725	0.0
1928	279,149	257,075	22,074	184,799	0.0
1929	216,508	192,712	23,796	208,595	0.0
1930	431,011	367,006	64,005	272,600	0.0
1931	477,030	410,549	66,481	339,081	0.0
1932	219,866	212,270	7,596	346,677	0.0
1933	37,623	34,759	2,864	349,541	0.0
1934	35,962	33,770	2,192	351,733	0.0
1935	26,889	25,037	1,852	353,585	0.0
1936	59,062	55,129	3,933	357,518	0.0
1937	40,971	38,363	2,608	360,126	0.0
1938	28,022	25,905	2,117	362,243	0.0
1939	51,849	47,454	4,395	366,638	0.0
1940	67,821	61,914	5,907	372,545	0.0
1941	108,399	97,399	11,000	383,545	0.0
1942	44,899	38,098	6,801	390,346	0.0
1943	25,304	23,745	1,559	391,905	0.0
1944	25,409	22,700	2,709	394,614	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1945	34,831	31,903	2,928	397,542	0.0
1946	496,080	394,253	101,827	499,369	0.0
1947	158,187	136,460	21,727	521,096	0.0
1948	291,399	254,033	37,366	558,462	0.0
1949	496,141	437,691	58,450	616,912	0.0
1950	2,127,171	1,661,605	465,566	1,082,478	0.0
1951	795,900	665,514	130,386	1,212,864	0.0
1952	2,739,331	2,386,742	352,589	1,565,453	0.0
1953	1,512,037	1,187,089	324,948	1,890,401	0.0
1954	2,777,238	2,196,747	580,491	2,470,892	0.1
1955	2,399,375	1,909,341	490,034	2,960,926	0.1
1956	4,359,507	3,453,917	905,590	3,866,516	0.1
1957	3,910,193	2,908,390	1,001,803	4,868,319	0.1
1958	3,901,651	2,819,360	1,082,291	5,950,610	0.1
1959	4,092,305	3,045,276	1,047,029	6,997,639	0.2
1960	5,115,871	3,770,535	1,345,336	8,342,975	0.2
1961	4,443,709	3,285,657	1,158,052	9,501,027	0.2
1962	4,318,664	3,155,204	1,163,460	10,664,487	0.3
1963	5,730,979	4,075,762	1,655,217	12,319,704	0.3
1964	7,273,139	5,133,535	2,139,604	14,459,308	0.4
1965	7,898,871	5,629,333	2,269,538	16,728,846	0.4
1966	8,804,558	6,304,115	2,500,443	19,229,289	0.5
1967	8,212,097	5,743,398	2,468,699	21,697,988	0.5
1968	10,645,702	7,360,543	3,285,159	24,983,147	0.6
1969	11,349,682	7,810,478	3,539,204	28,522,351	0.7
1970	10,418,547	7,198,696	3,219,851	31,742,202	0.8
1971	9,473,315	6,489,276	2,984,039	34,726,241	0.8
1972	10,965,341	7,329,637	3,635,704	38,361,945	0.9
1973	9,126,638	6,191,785	2,934,853	41,296,798	1.0
1974	10,598,733	7,393,150	3,205,583	44,502,381	1.1
1975	8,512,622	5,701,637	2,810,985	47,313,366	1.2
1976	8,200,207	5,554,315	2,645,892	49,959,258	1.2
1977	10,399,837	6,857,047	3,542,790	53,502,048	1.3
1978	9,984,716	6,400,048	3,584,668	57,086,716	1.4
1979	15,095,812	9,481,597	5,614,215	62,700,931	1.5
1980	25,365,870	15,955,865	9,410,005	72,110,936	1.8
1981	26,126,040	16,312,145	9,813,895	81,924,831	2.0
1982	25,559,746	16,624,176	8,935,570	90,860,401	2.2
1983	13,409,855	9,057,857	4,351,998	95,212,399	2.3
1984	18,121,560	11,927,352	6,194,208	101,406,607	2.5
1985	21,889,170	14,363,978	7,525,192	108,931,799	2.7
1986	26,630,871	16,873,278	9,757,593	118,689,392	2.9
1987	29,653,117	18,607,049	11,046,068	129,735,460	3.2
1988	42,268,322	25,757,923	16,510,399	146,245,859	3.6
1989	45,421,560	27,403,648	18,017,912	164,263,771	4.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
1990	49,123,293	29,204,325	19,918,968	184,182,739	4.5
1991	39,966,479	23,643,431	16,323,048	200,505,787	4.9
1992	42,774,637	25,256,803	17,517,834	218,023,621	5.3
1993	32,874,163	19,357,433	13,516,730	231,540,351	5.6
1994	50,164,973	28,678,369	21,486,604	253,026,955	6.2
1995	58,408,326	30,930,518	27,477,808	280,504,763	6.8
1996	61,775,379	31,675,588	30,099,791	310,604,554	7.6
1997	75,264,212	38,479,199	36,785,013	347,389,567	8.5
1998	58,745,842	29,464,035	29,281,807	376,671,374	9.2
1999	45,021,416	22,079,907	22,941,509	399,612,883	9.7
2000	61,876,477	28,957,496	32,918,981	432,531,864	10.5
2001	57,224,800	26,204,645	31,020,155	463,552,019	11.3
2002	56,390,884	26,162,865	30,228,019	493,780,038	12.0
2003	56,610,071	24,501,981	32,108,090	525,888,128	12.8
2004	73,629,297	31,891,695	41,737,602	567,625,730	13.8
2005	66,463,838	27,192,448	39,271,390	606,897,120	14.8
2006	66,120,126	27,635,225	38,484,901	645,382,021	15.7
2007	68,659,529	29,333,902	39,325,627	684,707,648	16.7
2008	70,611,115	28,517,438	42,093,677	726,801,325	17.7
2009	70,373,063	27,361,722	43,011,341	769,812,666	18.7
2010	59,012,487	19,264,949	39,747,538	809,560,204	19.7
2011	87,196,452	27,488,728	59,707,724	869,267,928	21.1
2012	107,956,646	31,674,143	76,282,503	945,550,431	23.0
2013	122,650,373	32,981,325	89,669,048	1,035,219,479	25.2
2014	156,522,225	39,088,948	117,433,277	1,152,652,756	28.0
2015	181,056,799	41,195,732	139,861,067	1,292,513,823	31.4
2016	200,093,267	41,241,168	158,852,099	1,451,365,922	35.3
2017	202,935,211	37,447,361	165,487,850	1,616,853,772	39.3
2018	290,999,840	48,766,150	242,233,690	1,859,087,462	45.2
2019	265,649,007	42,452,443	223,196,564	2,082,284,026	50.7
2020	269,438,574	40,515,188	228,923,386	2,311,207,412	56.2
2021	353,765,948	39,576,334	314,189,614	2,625,397,026	63.9
2022	415,517,991	38,543,181	376,974,810	3,002,371,836	73.0
2023	482,253,127	38,120,340	444,132,787	3,446,504,623	83.8
2024	340,069,610	14,693,560	325,376,050	3,771,880,673	91.8
2025	344,271,484	5,532,464	338,739,020	4,110,619,693	100.0
TOTAL	5,526,564,703	1,415,945,010	4,110,619,693		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1952					0.0
1953					0.0
2017					0.0
2019	33,513,297	6,437,362	27,075,935	27,075,935	51.1
2020	1,957,793	303,371	1,654,422	28,730,357	54.2
2021	1,734,664	834,881	899,783	29,630,140	55.9
2022	4,218,639	568,832	3,649,807	33,279,947	62.7
2023	11,849,883	893,092	10,956,791	44,236,738	83.4
2024	8,704,747	423,214	8,281,533	52,518,271	99.0
2025	532,025	13,835	518,190	53,036,461	100.0
SUBTOTAL	62,511,048	9,474,587	53,036,461		
NONDEPRECIABLE	7,086,071		7,086,071		
TOTAL	69,597,119	9,474,587	60,122,532		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST PCT OF COL 4 TOTAL (6)
2000	802,206	802,206			0.0
2001	18,800	18,800			0.0
2002	447,659	447,659			0.0
2004	1,403,265	1,403,265			0.0
2005	122,880	122,880			0.0
2006	2,693,931	2,693,931			0.0
2007	3,259,581	3,259,581			0.0
2009	440,869	440,869			0.0
2011	169,184	160,270	8,914	8,914	0.0
2012	2,739,344	2,735,081	4,263	13,177	0.0
2013	259,178	259,178		13,177	0.0
2014	740,529	740,529		13,177	0.0
2015	220,826	220,826		13,177	0.0
2016	2,224,484	1,669,247	555,237	568,414	0.5
2017	77,572,379	43,494,690	34,077,689	34,646,103	29.8
2018	1,545,759	1,146,175	399,584	35,045,687	30.2
2019	63,153,771	29,186,959	33,966,812	69,012,499	59.4
2020	12,600,895	7,142,743	5,458,152	74,470,651	64.1
2021	15,472,364	6,277,141	9,195,223	83,665,874	72.1
2022	11,236,969	4,251,843	6,985,126	90,651,000	78.1
2023	11,969,768	3,711,274	8,258,494	98,909,494	85.2
2024	10,728,182	2,330,375	8,397,807	107,307,301	92.4
2025	9,453,180	668,340	8,784,840	116,092,141	100.0
TOTAL	229,276,003	113,183,862	116,092,141		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1902	3,610.27	3,610	3,610			
1903	4,110.54	4,111	4,111			
1908	44.05	44	44			
1910	85.13	85	85			
1912	835.22	835	835			
1913	222.36	222	222			
1914	14.50	14	15			
1915	224.10	224	224			
1916	117.50	118	118			
1917	64.30	64	64			
1926	6,471.58	6,327	6,472			
1929	1,806.23	1,749	1,793	14	2.23	6
1930	2,041.31	1,969	2,018	23	2.47	9
1931	27,123.22	26,077	26,726	397	2.70	147
1932	2,640.53	2,529	2,592	49	2.95	17
1933	538.99	514	527	12	3.20	4
1934	812.94	773	792	21	3.45	6
1935	12.64	12	12			
1937	203.24	191	196	7	4.22	2
1938	375.47	351	360	16	4.49	4
1939	962.92	898	920	43	4.75	9
1940	6,450.60	5,988	6,137	314	5.02	63
1941	592.71	548	562	31	5.30	6
1942	337.44	311	319	19	5.58	3
1943	60.01	55	56	4	5.86	1
1944	422.25	385	395	28	6.15	5
1945	631.09	573	587	44	6.44	7
1946	3,351.10	3,028	3,103	248	6.75	37
1947	2,508.33	2,255	2,311	197	7.07	28
1948	4,635.54	4,146	4,249	386	7.39	52
1949	1,157.34	1,030	1,056	102	7.73	13
1950	190.65	169	173	17	8.09	2
1951	4,042.41	3,554	3,642	400	8.46	47
1952	198.20	173	177	21	8.85	2
1953	5,400.53	4,687	4,804	597	9.25	65
1954	14,353.89	12,369	12,677	1,677	9.68	173
1955	8,390.67	7,176	7,355	1,036	10.13	102
1956	78,471.52	66,589	68,247	10,225	10.60	965
1957	2,231.51	1,878	1,925	307	11.10	28
1958	3,854.85	3,215	3,295	560	11.61	48
1959	3,405.26	2,814	2,884	521	12.15	43

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	11,197.19	9,163	9,391	1,806	12.72	142
1961	2,660.99	2,155	2,209	452	13.30	34
1962	3,222.41	2,582	2,646	576	13.91	41
1963	3,157.03	2,501	2,563	594	14.54	41
1964	5,365.41	4,202	4,307	1,059	15.18	70
1965	6,572.95	5,087	5,214	1,359	15.83	86
1966	36,334.10	27,770	28,461	7,873	16.50	477
1967	22,318.73	16,841	17,260	5,058	17.18	294
1968	3,796.90	2,828	2,898	898	17.87	50
1969	12,470.57	9,162	9,390	3,080	18.57	166
1970	18,015.96	13,054	13,379	4,637	19.28	241
1971	1,199.64	857	878	321	20.00	16
1972	11,935.28	8,402	8,611	3,324	20.72	160
1973	5,080.37	3,523	3,611	1,470	21.46	68
1974	8,346.12	5,698	5,840	2,506	22.21	113
1975	11,480.98	7,712	7,904	3,577	22.98	156
1976	7,995.15	5,282	5,413	2,582	23.75	109
1977	11,905.30	7,733	7,926	3,980	24.53	162
1978	12,918.41	8,246	8,451	4,467	25.32	176
1979	7,570.24	4,744	4,862	2,708	26.13	104
1980	4,856.13	2,987	3,061	1,795	26.94	67
1981	73,749.17	44,492	45,600	28,150	27.77	1,014
1982	10,050.64	6,260	6,416	3,635	26.19	139
1983	9,041.47	5,501	5,638	3,404	27.19	125
1984	15,250.78	9,121	9,348	5,903	27.72	213
1985	26,754.50	15,614	16,003	10,752	28.72	374
1986	14,112.19	8,031	8,231	5,881	29.72	198
1987	3,342.10	1,866	1,912	1,430	30.25	47
1988	11,301.63	6,146	6,299	5,003	31.25	160
1989	1,090.00	581	595	495	31.78	16
1990	8,000.14	4,146	4,249	3,751	32.78	114
1991	117,309.04	59,065	60,535	56,774	33.78	1,681
1992	25,030.74	12,318	12,625	12,406	34.32	361
1993	12,460.42	5,947	6,095	6,365	35.32	180
1994	6,889.97	3,187	3,266	3,624	36.32	100
1995	12,673.77	5,712	5,854	6,820	36.87	185
1996	12,902.15	5,623	5,763	7,139	37.87	189
1997	66,170.17	27,851	28,544	37,626	38.87	968
1998	16,023.55	6,506	6,668	9,356	39.87	235
1999	3,898.06	1,525	1,563	2,335	40.87	57
2000	5,089.04	1,928	1,976	3,113	41.41	75

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2001	2,659.41	967	991	1,668	42.41	39
2002	551.45	192	197	355	43.41	8
2003	1,306.89	436	447	860	44.41	19
2004	373.65	119	122	252	45.41	6
2007	10,611.38	2,924	2,997	7,615	47.97	159
2024	114.45	3	3	111	64.29	2
	868,159.56	558,250	571,904	296,256		11,331

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.1 1.31

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
1915	44.03	44	44			
1931	22.41	22	22			
1936	428.90	429	429			
1939	2,662.19	2,662	2,662			
1940	342.66	343	343			
1946	195.14	195	195			
1953	97.16	97	97			
1954	398.72	399	399			
1955	1,082.26	1,082	1,082			
1956	2,295.78	2,296	2,296			
1957	310.18	310	310			
1958	2,058.46	2,058	2,058			
1959	300.33	300	300			
1960	6,541.37	6,541	6,541			
1961	4,353.35	4,353	4,353			
1962	2,282.71	2,283	2,283			
1963	736.08	736	736			
1964	190.55	191	191			
1965	2,343.06	2,341	2,343			
1966	2,250.24	2,224	2,250			
1967	9,977.71	9,752	9,978			
1968	2,151.32	2,079	2,151			
1969	544.69	520	545			
1970	40.03	38	40			
1971	1,214.19	1,134	1,214			
1973	700.59	640	701			
1974	4,750.87	4,295	4,751			
1977	193.66	169	194			
1978	2,207.46	1,904	2,207			
1979	2,203.60	1,877	2,204			
1983	5,281.99	4,664	5,282			
1984	369.17	323	369			
1985	9,821.44	8,499	9,821			
1986	241.46	208	241			
1987	1,014.54	862	1,015			
1988	31,015.80	25,994	31,016			
1989	44,844.88	37,064	44,845			
1994	601.90	463	602			
1996	1,215.58	903	1,216			
1998	1,575.63	1,125	1,576			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	1,077	1,760			
2019	11,416.29	2,945	5,970	5,446	18.69	291
2020	138.01	31	63	75	18.77	4
	162,216.47	135,472	156,695	5,521		295

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.7 0.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1900	71,113.66	67,586	71,114			
1902	24,056.23	22,693	24,056			
1903	33,197.34	31,201	33,197			
1904	1,964.62	1,840	1,965			
1906	2,420.69	2,252	2,421			
1907	8,730.25	8,095	8,730			
1910	749.15	688	749			
1913	1,738.46	1,582	1,738			
1915	63.32	57	63			
1922	35.55	31	36			
1925	1,356.81	1,184	1,357			
1926	46,464.38	40,405	46,464			
1927	2,171.63	1,881	2,172			
1928	180.25	156	180			
1929	27,529.19	23,661	27,529			
1930	2,522.76	2,159	2,523			
1931	296.56	253	297			
1932	122,819.26	104,233	122,819			
1933	4,897.35	4,138	4,897			
1934	10,855.44	9,130	10,855			
1935	1,410.95	1,181	1,411			
1936	16,622.35	13,848	16,622			
1937	2,388.88	1,980	2,389			
1938	2,797.65	2,307	2,798			
1939	797.65	654	798			
1940	11,364.66	9,270	11,365			
1941	11,633.51	9,436	11,634			
1942	1,215.69	980	1,211	4	14.53	
1943	5,838.88	4,679	5,784	55	14.90	4
1944	48.34	38	47	1	15.28	
1945	1,498.10	1,185	1,465	33	15.67	2
1946	4,905.03	3,853	4,763	142	16.08	9
1947	24,941.60	19,458	24,052	889	16.49	54
1948	98,837.20	76,540	94,612	4,225	16.92	250
1949	28,199.11	21,672	26,789	1,410	17.36	81
1950	2,735.68	2,086	2,579	157	17.81	9
1951	202,177.37	152,927	189,036	13,142	18.27	719
1952	22,207.66	16,659	20,592	1,615	18.74	86
1953	200,020.82	148,735	183,854	16,167	19.23	841
1954	797,823.90	588,052	726,901	70,922	19.72	3,596
1955	81,749.31	59,699	73,795	7,954	20.23	393

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1956	1,473,781.22	1,066,030	1,317,739	156,043	20.75	7,520
1957	311,182.44	222,891	275,520	35,663	21.28	1,676
1958	299,804.72	212,583	262,778	37,027	21.82	1,697
1959	613,382.04	430,349	531,962	81,420	22.38	3,638
1960	674,919.59	468,482	579,099	95,821	22.94	4,177
1961	47,891.52	32,879	40,642	7,249	23.51	308
1962	190,718.09	129,435	159,997	30,721	24.10	1,275
1963	122,060.87	81,878	101,211	20,850	24.69	844
1964	290,969.66	192,855	238,391	52,578	25.29	2,079
1965	701,420.51	459,101	567,503	133,918	25.91	5,169
1966	742,304.44	479,729	593,002	149,303	26.53	5,628
1967	215,827.53	137,670	170,176	45,651	27.16	1,681
1968	370,389.64	233,097	288,135	82,254	27.80	2,959
1969	640,487.71	397,532	491,396	149,091	28.45	5,240
1970	874,219.01	534,908	661,209	213,010	29.11	7,317
1971	453,818.02	273,620	338,227	115,591	29.78	3,881
1972	966,536.05	574,122	709,682	256,854	30.45	8,435
1973	372,161.96	217,640	269,029	103,133	31.14	3,312
1974	485,847.07	279,654	345,685	140,162	31.83	4,403
1975	297,092.08	168,273	208,005	89,087	32.52	2,739
1976	137,471.87	76,562	94,640	42,832	33.23	1,289
1977	134,299.99	73,525	90,886	43,414	33.94	1,279
1978	287,058.05	154,400	190,857	96,201	34.66	2,776
1979	501,981.46	265,111	327,708	174,273	35.39	4,924
1980	243,613.68	126,258	156,070	87,544	36.13	2,423
1981	283,711.51	144,239	178,296	105,415	36.87	2,859
1982	319,398.12	180,971	223,701	95,697	33.08	2,893
1983	524,887.81	292,730	361,849	163,039	33.51	4,865
1984	749,802.45	408,267	504,666	245,136	34.51	7,103
1985	455,843.70	244,013	301,629	154,215	34.94	4,414
1986	565,064.08	297,224	367,404	197,660	35.37	5,588
1987	414,536.27	212,491	262,664	151,872	36.37	4,176
1988	491,903.15	247,378	305,788	186,115	36.82	5,055
1989	207,476.32	102,286	126,438	81,039	37.28	2,174
1990	360,151.18	172,656	213,423	146,728	38.28	3,833
1991	2,298,208.76	1,078,320	1,332,930	965,278	38.74	24,917
1992	1,177,930.89	540,435	668,041	509,890	39.22	13,001
1993	1,136,543.85	505,762	625,181	511,362	40.22	12,714
1994	971,986.45	422,231	521,927	450,059	40.69	11,061
1995	571,362.11	241,972	299,106	272,256	41.18	6,611
1996	804,324.21	329,371	407,141	397,183	42.18	9,416

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1997	1,997,584.37	795,638	983,502	1,014,082	42.67	23,766
1998	1,718,962.57	665,239	822,314	896,649	43.17	20,770
1999	1,080,765.90	405,720	501,518	579,248	43.68	13,261
2000	2,093,639.95	756,013	934,521	1,159,119	44.68	25,943
2001	940,486.78	328,418	405,963	534,523	45.19	11,828
2002	1,450,386.34	488,925	604,369	846,017	45.72	18,504
2003	537,154.95	173,286	214,202	322,953	46.72	6,913
2004	239,158.46	74,187	91,704	147,455	47.25	3,121
2005	237,738.75	70,775	87,486	150,253	47.78	3,145
2006	169,927.36	48,412	59,843	110,084	48.32	2,278
2007	509,991.81	137,749	170,274	339,718	49.32	6,888
2008	103,422.99	26,973	33,342	70,081	49.61	1,413
2009	74,105.67	18,341	22,672	51,434	50.17	1,025
2010	158,384.81	37,062	45,813	112,572	50.73	2,219
2011	140,623.77	30,797	38,069	102,555	51.72	1,983
2012	2,357,530.59	483,765	597,990	1,759,540	52.29	33,650
2013	41,989.81	8,028	9,924	32,066	52.86	607
2024	307,730.46	7,939	9,814	297,917	56.64	5,260
2025	643,848.72	5,859	7,242	636,606	54.45	11,692
	39,468,181.38	18,730,520	23,115,954	16,352,228		407,659

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.1 1.03

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1927	43.41	43	43			
1935	1.00	1	1			
1937	63.36	62	63			
1938	130.20	128	130			
1939	199.99	195	200			
1940	188.95	183	189			
1942	115.52	111	116			
1943	207.70	198	208			
1944	83.77	79	84			
1945	174.42	164	174			
1946	163.63	153	164			
1947	277.29	258	277			
1948	89.09	83	89			
1950	7.97	7	8			
1952	18.79	17	19			
1953	5,944.35	5,379	5,944			
1954	8,508.82	7,660	8,509			
1955	7,542.08	6,756	7,542			
1956	39,702.37	35,376	39,702			
1957	13,574.54	12,032	13,575			
1958	6,469.06	5,702	6,469			
1959	9,801.88	8,594	9,802			
1960	24,067.26	20,978	24,067			
1961	5,498.45	4,765	5,468	30	6.54	5
1962	12,455.03	10,729	12,313	142	6.79	21
1963	5,203.12	4,454	5,112	92	7.05	13
1964	19,172.75	16,309	18,717	456	7.32	62
1965	16,408.17	13,863	15,909	499	7.60	66
1966	43,116.46	36,174	41,514	1,602	7.89	203
1967	18,626.28	15,513	17,803	823	8.19	100
1968	18,055.59	14,920	17,123	933	8.51	110
1969	32,278.33	26,455	30,360	1,918	8.84	217
1970	15,250.12	12,393	14,222	1,028	9.18	112
1971	26,308.31	21,186	24,314	1,995	9.54	209
1972	26,694.33	21,290	24,433	2,261	9.92	228
1973	12,036.90	9,504	10,907	1,130	10.31	110
1974	18,632.52	14,556	16,705	1,928	10.72	180
1975	30,467.80	23,535	27,009	3,459	11.15	310
1976	138,678.97	105,877	121,507	17,172	11.59	1,482
1977	14,832.80	11,182	12,833	2,000	12.06	166
1978	22,161.07	16,490	18,924	3,237	12.54	258

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2.5						
NET SALVAGE PERCENT.. 0						
1979	41,008.38	30,095	34,538	6,471	13.04	496
1980	13,577.55	9,823	11,273	2,304	13.55	170
1981	82,437.31	58,732	67,402	15,035	14.09	1,067
1982	156,832.69	120,055	137,778	19,055	13.25	1,438
1983	24,048.18	18,188	20,873	3,175	13.61	233
1984	50,677.87	37,628	43,183	7,495	14.31	524
1985	86,879.75	63,648	73,044	13,836	14.69	942
1986	86,985.91	62,821	72,095	14,891	15.10	986
1987	52,185.49	36,926	42,377	9,808	15.81	620
1988	411,643.09	286,751	329,082	82,561	16.22	5,090
1989	41,658.60	28,390	32,581	9,078	16.94	536
1990	297,917.74	199,545	229,002	68,915	17.38	3,965
1991	147,610.27	96,567	110,822	36,788	18.10	2,032
1992	264,883.76	169,976	195,068	69,816	18.56	3,762
1993	163,266.69	102,678	117,836	45,431	19.03	2,387
1994	349,935.44	214,335	245,976	103,960	19.77	5,258
1995	117,235.62	70,224	80,591	36,645	20.25	1,810
1996	215,121.50	125,222	143,708	71,414	21.00	3,401
1997	728,580.35	413,688	474,758	253,823	21.50	11,806
1998	560,594.04	308,551	354,100	206,494	22.26	9,276
1999	16,725.51	8,957	10,279	6,446	22.77	283
2000	174,732.10	90,441	103,792	70,940	23.53	3,015
2001	495,273.00	248,627	285,330	209,943	24.06	8,726
2002	154,135.03	74,540	85,544	68,591	24.83	2,762
2003	301,200.83	140,721	161,495	139,706	25.37	5,507
2004	59,852.58	26,964	30,944	28,908	25.92	1,115
2005	86,161.34	37,161	42,647	43,515	26.70	1,630
2006	82,235.60	34,037	39,062	43,174	27.26	1,584
2007	11,729.27	4,624	5,307	6,423	28.05	229
2008	249,781.89	95,292	109,359	140,423	28.37	4,950
2012	21,662.45	6,551	7,518	14,144	31.14	454
2013	8,571.24	2,421	2,778	5,793	31.75	182
2021	1,310.54	144	165	1,145	36.48	31
2022	23,129.77	1,998	2,293	20,837	36.99	563
	6,172,833.83	3,709,675	4,255,146	1,917,688		90,682

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.1 1.47

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1955	5,466.25	5,466	5,466			
1965	7,727.57	7,728	7,728			
1966	1,743.15	1,743	1,743			
1967	249.76	250	250			
1968	2,500.34	2,500	2,500			
1972	1,946.45	1,946	1,946			
1979	706.12	706	706			
1982	5,572.11	5,422	5,572			
1983	1,354.71	1,299	1,355			
1984	2,338.50	2,219	2,339			
1985	8,363.40	7,877	8,363			
1986	1,865.01	1,735	1,865			
1987	8,236.27	7,561	8,236			
1988	56,812.32	51,637	56,812			
1989	6,202.17	5,576	6,202			
1990	81,477.96	72,377	81,478			
1991	19,398.63	17,009	19,399			
1992	11,826.34	10,224	11,826			
1993	4,988.84	4,263	4,989			
1994	24,237.82	20,452	24,238			
1995	53,971.10	44,731	53,971			
1996	2,814.71	2,297	2,815			
1997	270.53	218	271			
2000	83,012.05	63,089	78,563	4,449	7.97	558
2001	21,876.59	16,287	20,282	1,595	8.32	192
2004	19,336.59	13,396	16,682	2,655	9.42	282
2009	679,443.48	405,832	505,369	174,074	11.12	15,654
2010	158,522.71	90,913	113,211	45,312	11.53	3,930
2011	574,467.00	316,531	394,166	180,301	11.82	15,254
2012	649,682.90	341,213	424,901	224,782	12.21	18,410
2013	552,258.31	276,129	343,854	208,404	12.50	16,672
2014	229,452.61	108,715	135,379	94,073	12.77	7,367
2015	208,014.12	92,608	115,322	92,692	13.08	7,087
2022	19,067.98	3,890	4,844	14,224	13.65	1,042
	3,505,204.40	2,003,839	2,462,642	1,042,562		86,448

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 2.47

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1931	73.41	73	73			
1932	22.79	23	23			
1934	159.65	160	160			
1935	148.67	149	149			
1937	75.60	76	76			
1938	348.00	348	348			
1952	193.45	193	193			
1956	802.14	802	802			
1958	54.05	54	54			
1959	1,630.62	1,631	1,631			
1962	268.78	265	269			
1964	542.39	527	542			
1965	237.71	229	238			
1966	1,610.42	1,541	1,610			
1967	1,046.31	993	1,046			
1968	8,185.23	7,706	8,185			
1969	1,294.81	1,210	1,295			
1970	2,302.48	2,136	2,302			
1971	4,402.26	4,055	4,402			
1972	6,378.34	5,837	6,378			
1973	2,116.13	1,923	2,116			
1974	772.96	698	773			
1975	728.51	653	729			
1976	666.84	593	667			
1977	2,372.22	2,094	2,356	16	4.10	4
1978	395.78	347	390	5	4.34	1
1979	1,489.70	1,295	1,457	32	4.58	7
1980	1,156.83	997	1,122	35	4.83	7
1981	1,410.00	1,205	1,356	54	5.09	11
1982	4,310.08	3,859	4,310			
1983	3,348.16	2,970	3,343	5	5.37	1
1984	3,634.15	3,208	3,611	23	5.48	4
1985	5,292.73	4,623	5,204	88	5.83	15
1986	1,466.52	1,266	1,425	41	6.20	7
1987	1,617.48	1,386	1,560	57	6.39	9
1988	7,215.84	6,102	6,869	347	6.80	51
1989	11,462.74	9,558	10,760	703	7.23	97
1990	14,888.28	12,280	13,824	1,064	7.49	142
1991	14,350.24	11,648	13,113	1,238	7.95	156
1992	10,561.54	8,428	9,488	1,074	8.42	128

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1993	9,905.10	7,794	8,774	1,131	8.73	130
1994	3,879.74	2,995	3,372	508	9.23	55
1995	7,818.56	5,912	6,655	1,163	9.75	119
	140,637.24	119,842	133,053	7,584		944

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 0.67

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1982	15,664.23	15,664	15,664			
1983	11,125.29	11,125	11,125			
1985	4,384.63	4,385	4,385			
1986	38,021.86	38,022	38,022			
1990	11,962.90	11,963	11,963			
1991	2,199.99	2,125	2,200			
1992	1,383.30	1,383	1,383			
1995	24,385.78	23,827	24,386			
1996	494.25	477	494			
2015	100,388.74	53,447	58,228	42,161	9.22	4,573
	210,010.97	162,418	167,850	42,161		4,573

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.2 2.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1903	298.00	294	298			
1904	222.17	218	222			
1929	410.41	369	410			
1930	548.08	490	548			
1931	10,677.87	9,513	10,651	27	8.18	3
1932	38.71	34	38	1	8.46	
1933	55.00	49	55			
1934	123.52	109	122	1	9.04	
1935	533.10	467	523	10	9.34	1
1936	100.54	88	99	2	9.65	
1937	223.29	194	217	6	9.96	1
1938	178.56	154	172	6	10.28	1
1939	285.78	245	274	11	10.62	1
1940	249.96	213	238	11	10.96	1
1941	57.82	49	55	3	11.31	
1942	19.44	16	18	2	11.68	
1944	36.92	31	35	2	12.44	
1945	59.80	50	56	4	12.84	
1946	160.11	132	148	12	13.25	1
1947	235.63	193	216	20	13.67	1
1948	51.03	41	46	5	14.11	
1949	2,077.70	1,675	1,875	202	14.55	14
1950	1,726.56	1,381	1,546	180	15.01	12
1951	360.18	286	320	40	15.49	3
1952	287.05	226	253	34	15.97	2
1953	1,145.40	894	1,001	144	16.47	9
1954	877.98	679	760	118	16.98	7
1955	3,133.21	2,402	2,689	444	17.51	25
1956	1,794.30	1,363	1,526	268	18.04	15
1957	5,277.55	3,969	4,444	834	18.59	45
1958	1,136.57	846	947	189	19.15	10
1959	1,431.64	1,055	1,181	250	19.72	13
1960	1,139.60	831	930	209	20.31	10
1961	1,739.80	1,255	1,405	335	20.91	16
1962	534.64	381	427	108	21.51	5
1963	1,024.78	722	808	216	22.13	10
1964	2,424.42	1,689	1,891	533	22.76	23
1965	1,904.74	1,310	1,467	438	23.40	19
1966	14,200.26	9,647	10,801	3,399	24.05	141
1967	36,083.66	24,195	27,089	8,995	24.71	364
1968	18,362.30	12,148	13,601	4,761	25.38	188

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1969	11,282.03	7,362	8,243	3,040	26.06	117
1970	6,080.40	3,912	4,380	1,701	26.75	64
1971	15,534.05	9,849	11,027	4,507	27.45	164
1972	18,498.57	11,553	12,935	5,564	28.16	198
1973	38,364.70	23,592	26,414	11,951	28.88	414
1974	49,272.90	29,826	33,393	15,880	29.60	536
1975	37,863.68	22,552	25,249	12,614	30.33	416
1976	13,898.67	8,139	9,112	4,786	31.08	154
1977	19,181.60	11,043	12,364	6,818	31.82	214
1978	24,833.70	14,046	15,726	9,108	32.58	280
1979	27,735.34	15,402	17,244	10,491	33.35	315
1980	38,526.40	21,000	23,512	15,015	34.12	440
1981	41,644.61	22,266	24,929	16,716	34.90	479
1982	29,660.39	17,061	19,102	10,559	31.94	331
1983	47,020.30	26,623	29,807	17,213	32.37	532
1984	51,245.11	28,328	31,716	19,529	33.37	585
1985	70,214.20	38,154	42,717	27,497	33.82	813
1986	74,675.20	39,570	44,303	30,372	34.82	872
1987	61,590.79	32,040	35,872	25,719	35.28	729
1988	64,488.00	32,670	36,577	27,911	36.28	769
1989	63,293.80	31,432	35,191	28,102	36.74	765
1990	76,971.45	37,439	41,917	35,055	37.22	942
1991	69,790.71	32,983	36,928	32,863	38.22	860
1992	74,877.76	34,609	38,748	36,129	38.69	934
1993	94,389.03	42,315	47,376	47,013	39.69	1,185
1994	63,758.76	27,894	31,230	32,529	40.18	810
1995	64,141.55	27,164	30,413	33,729	41.18	819
1996	101,676.17	41,931	46,946	54,730	41.67	1,313
1997	147,067.21	58,577	65,583	81,484	42.67	1,910
1998	219,807.88	85,066	95,240	124,568	43.17	2,886
1999	109,098.49	40,672	45,537	63,562	44.17	1,439
2000	148,695.59	53,694	60,116	88,580	44.68	1,983
2001	49,857.74	17,291	19,359	30,499	45.68	668
2002	51,469.65	17,232	19,293	32,177	46.19	697
2003	48,988.25	15,696	17,573	31,415	47.19	666
2004	503,472.20	155,120	173,673	329,799	47.72	6,911
2005	99,247.65	29,139	32,624	66,624	48.72	1,367
2006	21,099.30	5,889	6,593	14,506	49.72	292
2007	21,366.27	5,692	6,373	14,993	50.25	298
2008	132,857.20	33,945	38,005	94,852	50.99	1,860
2009	5,977.08	1,450	1,623	4,354	51.52	85

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2010	18,300.47	4,169	4,668	13,633	52.53	260
2011	20,776.70	4,459	4,992	15,784	53.07	297
2012	7,943.52	1,587	1,777	6,167	54.07	114
2013	93,193.26	17,353	19,428	73,765	54.62	1,351
2014	11,063.41	1,896	2,123	8,941	55.61	161
2015	2,375.70	372	416	1,959	56.62	35
2016	108,946.54	15,525	17,382	91,565	57.17	1,602
2017	88,797.46	11,322	12,676	76,121	58.17	1,309
2018	1,675.04	190	213	1,462	58.73	25
2019	189.14	19	21	168	59.72	3
	3,374,003.70	1,347,013	1,508,064	1,865,940		43,210

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.2 1.28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	770.06	770	770			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,545	1,545			
1923	444.90	445	445			
1924	49,481.98	49,482	49,482			
1925	9,550.78	9,551	9,551			
1926	1,437.54	1,429	1,438			
1927	12,577.28	12,416	12,577			
1928	169.18	166	169			
1929	1,786.94	1,739	1,787			
1930	5,907.90	5,708	5,908			
1931	886.67	851	887			
1932	690.68	658	691			
1933	4,845.58	4,583	4,846			
1934	599.15	563	599			
1937	206.12	189	206			
1939	941.28	852	941			
1941	1,497.83	1,336	1,498			
1942	1,321.59	1,170	1,322			
1943	3,799.03	3,338	3,799			
1944	480.46	419	480			
1945	7,388.06	6,392	7,375	13	6.74	2
1946	24,241.93	20,809	24,010	232	7.08	33
1947	1,212.46	1,033	1,192	21	7.42	3
1948	11,813.70	9,980	11,515	299	7.76	39
1949	155,416.10	130,239	150,271	5,145	8.10	635
1950	314,103.69	261,083	301,241	12,863	8.44	1,524
1951	117,565.93	96,898	111,802	5,764	8.79	656
1952	14,011.46	11,450	13,211	800	9.14	88
1953	64,035.02	51,894	59,876	4,159	9.48	439

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1954	82,747.60	66,479	76,704	6,043	9.83	615
1955	21,708.32	17,284	19,942	1,766	10.19	173
1956	33,265.27	26,253	30,291	2,974	10.54	282
1957	16,795.88	13,134	15,154	1,642	10.90	151
1958	16,398.95	12,706	14,660	1,739	11.26	154
1959	32,555.72	24,990	28,834	3,722	11.62	320
1960	28,812.28	21,909	25,279	3,533	11.98	295
1961	30,404.90	22,895	26,417	3,988	12.35	323
1962	27,753.65	20,693	23,876	3,878	12.72	305
1963	14,913.85	11,009	12,702	2,212	13.09	169
1964	4,880.13	3,565	4,113	767	13.47	57
1965	18,536.25	13,402	15,463	3,073	13.85	222
1966	5,038.93	3,605	4,159	879	14.23	62
1967	4,718.58	3,339	3,853	866	14.62	59
1968	4,278.86	2,994	3,455	824	15.01	55
1969	8,771.59	6,068	7,001	1,770	15.41	115
1970	5,741.53	3,927	4,531	1,211	15.80	77
1971	25,767.69	17,414	20,092	5,675	16.21	350
1973	11,871.49	7,830	9,034	2,837	17.02	167
1974	25,525.37	16,622	19,179	6,347	17.44	364
1975	87,663.74	56,350	65,017	22,646	17.86	1,268
1976	4,598.73	2,917	3,366	1,233	18.29	67
1977	8,040.17	5,030	5,804	2,236	18.72	119
1978	13,389.00	8,261	9,532	3,857	19.15	201
1979	6,024.51	3,664	4,228	1,797	19.59	92
1980	2,625.97	1,573	1,815	811	20.04	40
1981	3,896.41	2,300	2,654	1,243	20.49	61
1982	4,195.18	2,958	3,413	782	18.10	43
1984	107,312.77	73,488	84,791	22,521	18.99	1,186
1985	3,250.91	2,198	2,536	715	19.27	37
1987	11,800.00	7,763	8,957	2,843	19.89	143
1989	18,115.32	11,558	13,336	4,780	20.57	232
1993	4,421.64	2,624	3,028	1,394	22.10	63
1995	3,605.96	2,062	2,379	1,227	22.66	54
1996	28,053.64	15,674	18,085	9,969	23.10	432
1998	37,254.30	19,898	22,959	14,296	23.77	601
1999	24,770.91	12,876	14,856	9,914	24.25	409
2000	23,959.75	12,160	14,030	9,929	24.50	405
2001	34,304.98	16,888	19,486	14,819	25.01	593
2002	6,262.15	3,000	3,461	2,801	25.29	111
2003	8,507.00	3,956	4,564	3,943	25.60	154

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2004	14,150.50	6,345	7,321	6,830	26.14	261
2005	14,063.28	6,095	7,032	7,031	26.48	266
2006	17,523.06	7,319	8,445	9,078	26.83	338
2007	55,195.64	22,161	25,570	29,626	27.20	1,089
2008	20,558.92	7,987	9,215	11,343	27.55	412
2011	27,987.49	9,376	10,818	17,169	28.79	596
2013	103,921.61	30,917	35,672	68,249	29.52	2,312
2014	188,343.09	52,209	60,239	128,104	29.99	4,272
2019	56,478.77	9,545	11,013	45,466	31.96	1,423
2020	20,252.13	2,941	3,393	16,859	32.38	521
2021	3,292.94	397	458	2,835	32.81	86
2022	36,972.61	3,535	4,079	32,894	33.13	993
2024	446,028.38	18,912	21,821	424,207	33.84	12,536
2025	65,974.61	950	1,096	64,878	34.10	1,903
	2,781,411.12	1,488,392	1,698,044	1,083,367		41,053
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,142	4,142			
1927	2,693.18	2,659	2,693			
1930	189.29	183	189			
1933	847.72	802	848			
1936	544.45	504	544			
1938	32.84	30	33			
1952	9,309.40	7,608	8,976	334	9.14	37
1956	5,775.22	4,558	5,377	398	10.54	38
1957	65,555.21	51,264	60,479	5,076	10.90	466
1958	3,928.05	3,043	3,590	338	11.26	30
1959	1,740.26	1,336	1,576	164	11.62	14
1960	10,837.04	8,240	9,721	1,116	11.98	93
1961	15,060.14	11,340	13,378	1,682	12.35	136
1962	44,412.35	33,114	39,066	5,346	12.72	420
1963	61,579.91	45,458	53,629	7,951	13.09	607
1964	33,613.04	24,558	28,972	4,641	13.47	345
1965	24,411.66	17,650	20,823	3,589	13.85	259
1966	17,104.75	12,237	14,437	2,668	14.23	187

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1967	43,814.66	31,003	36,576	7,239	14.62	495
1968	31,758.04	22,224	26,219	5,539	15.01	369
1969	35,461.98	24,533	28,943	6,519	15.41	423
1970	109,477.63	74,883	88,343	21,134	15.80	1,338
1971	28,682.10	19,383	22,867	5,815	16.21	359
1972	14,929.02	9,970	11,762	3,167	16.61	191
1973	43,388.65	28,619	33,763	9,625	17.02	566
1974	6,679.10	4,349	5,131	1,548	17.44	89
1975	2,388.78	1,536	1,812	577	17.86	32
1976	325.75	207	244	82	18.29	4
1977	310.42	194	229	82	18.72	4
1978	5,350.19	3,301	3,894	1,456	19.15	76
1980	6,000.02	3,595	4,241	1,759	20.04	88
1981	66,216.28	39,081	46,106	20,110	20.49	981
1982	55,560.11	39,170	46,211	9,349	18.10	517
1983	28,861.79	20,120	23,737	5,125	18.36	279
1984	5,806.34	3,976	4,691	1,116	18.99	59
1985	10,388.00	7,024	8,287	2,101	19.27	109
1986	10,162.46	6,780	7,999	2,164	19.58	111
1987	21,773.61	14,325	16,900	4,874	19.89	245
1988	9,500.30	6,158	7,265	2,235	20.22	111
1989	21,764.75	13,886	16,382	5,383	20.57	262
1990	17,697.49	11,103	13,099	4,599	20.93	220
1991	2,527.62	1,558	1,838	690	21.31	32
1993	14,187.04	8,419	9,932	4,255	22.10	193
1994	31,906.90	18,646	21,998	9,909	22.22	446
1995	24,723.97	14,135	16,676	8,048	22.66	355
1996	64,217.36	35,878	42,327	21,890	23.10	948
1997	106,890.33	58,576	69,105	37,785	23.30	1,622
1998	90,466.61	48,318	57,003	33,463	23.77	1,408
1999	26,987.42	14,028	16,550	10,438	24.25	430
2000	20,094.65	10,198	12,031	8,064	24.50	329
2001	27,792.71	13,682	16,141	11,651	25.01	466
2002	74,704.50	35,783	42,215	32,489	25.29	1,285
2003	35,723.93	16,612	19,598	16,126	25.60	630
2004	12,600.58	5,650	6,666	5,935	26.14	227
2005	1,094.30	474	559	535	26.48	20
2006	2,275.29	950	1,121	1,155	26.83	43
2007	50,329.62	20,207	23,839	26,490	27.20	974
2008	4,380.00	1,702	2,008	2,372	27.55	86
2009	6,511.91	2,417	2,851	3,660	27.95	131

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2010	2,023.74	715	844	1,180	28.36	42
2014	1,151,949.73	319,320	376,718	775,232	29.99	25,850
2017	18,705.63	4,007	4,727	13,978	31.18	448
2019	630,236.94	106,510	125,655	504,582	31.96	15,788
2020	35,373.19	5,136	6,059	29,314	32.38	905
2023	6,264.54	435	513	5,751	33.47	172
2024	2,560.25	109	129	2,432	33.84	72
	3,323,085.84	1,358,093	1,600,760	1,722,326		62,462
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1900	123.38	123	123			
1902	2,860.00	2,860	2,860			
1908	2,901.80	2,902	2,902			
1910	7,556.70	7,557	7,557			
1915	161.12	161	161			
1923	266.11	266	266			
1925	212.80	213	213			
1927	13,724.13	13,548	13,724			
1928	894.16	876	894			
1930	38.28	37	38			
1936	572.62	530	573			
1937	4,600.60	4,227	4,569	32	4.06	8
1945	12.36	11	12			
1947	432.79	369	399	34	7.42	5
1948	6,857.71	5,793	6,262	596	7.76	77
1949	1,464.38	1,227	1,326	138	8.10	17
1950	23,781.96	19,768	21,367	2,415	8.44	286
1952	8.07	7	8	1	9.14	
1953	1,809.10	1,466	1,585	225	9.48	24
1954	0.60			1	9.83	
1955	768.66	612	662	107	10.19	11
1956	123.78	98	106	18	10.54	2
1957	1,865.14	1,459	1,577	288	10.90	26
1959	2,255.90	1,732	1,872	384	11.62	33
1960	2,692.32	2,047	2,213	480	11.98	40
1961	2,889.36	2,176	2,352	537	12.35	43
1962	2,147.00	1,601	1,730	417	12.72	33

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1963	1,552.28	1,146	1,239	314	13.09	24
1964	251.74	184	199	53	13.47	4
1965	898.68	650	703	196	13.85	14
1966	2,957.44	2,116	2,287	670	14.23	47
1967	6,310.72	4,465	4,826	1,485	14.62	102
1968	8,455.01	5,917	6,396	2,059	15.01	137
1969	1,245.94	862	932	314	15.41	20
1970	15,473.04	10,584	11,440	4,033	15.80	255
1971	1,369.67	926	1,001	369	16.21	23
1972	1,726.18	1,153	1,246	480	16.61	29
1973	486.52	321	347	140	17.02	8
1974	909.12	592	640	269	17.44	15
1975	1,641.93	1,055	1,140	502	17.86	28
1977	1,522.09	952	1,029	493	18.72	26
1980	1,579.82	947	1,024	556	20.04	28
1984	1,166.22	799	864	303	18.99	16
1985	57,181.74	38,666	41,794	15,388	19.27	799
1986	5,760.94	3,844	4,155	1,606	19.58	82
1988	3,798.31	2,462	2,661	1,137	20.22	56
1989	1,768.35	1,128	1,219	549	20.57	27
1990	2,041.00	1,281	1,385	656	20.93	31
1991	2,626.45	1,619	1,750	876	21.31	41
1994	422.40	247	267	155	22.22	7
1995	825.00	472	510	315	22.66	14
1996	2,848.85	1,592	1,721	1,128	23.10	49
1997	2,075.00	1,137	1,229	846	23.30	36
2003	2,542.54	1,182	1,278	1,265	25.60	49
2004	5,268.60	2,362	2,553	2,716	26.14	104
2006	3,944.55	1,648	1,781	2,163	26.83	81
2007	1,852.48	744	804	1,048	27.20	39
2011	2,856.60	957	1,034	1,822	28.79	63
2012	17,301.02	5,488	5,932	11,369	29.06	391
2015	14,100.64	3,627	3,920	10,180	30.32	336
2016	24,876.66	5,861	6,335	18,542	30.82	602
2017	102,422.10	21,939	23,714	78,709	31.18	2,524
2018	151,278.96	29,046	31,395	119,884	31.56	3,799
2019	53,035.35	8,963	9,688	43,347	31.96	1,356
2020	8,630.89	1,253	1,354	7,277	32.38	225

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2023	79,513.69	5,526	5,973	73,541	33.47	2,197
2024	294,849.51	12,502	13,513	281,336	33.84	8,314
2025	106,059.63	1,527	1,651	104,409	34.10	3,062
	1,076,448.49	259,408	278,277	798,171		25,665
	7,180,945.45	3,105,893	3,577,081	3,603,864		129,180
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.9	1.80

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1924	105,072.26	92,057	89,238	15,834	9.29	1,704
1925	16,078.22	14,035	13,605	2,473	9.53	259
1926	296,126.75	257,512	249,627	46,500	9.78	4,755
1927	22,548.31	19,533	18,935	3,613	10.03	360
1928	114,037.09	98,406	95,393	18,644	10.28	1,814
1929	133,799.34	114,997	111,476	22,324	10.54	2,118
1930	311,240.08	266,422	258,264	52,976	10.80	4,905
1931	161,660.76	137,800	133,581	28,080	11.07	2,537
1932	16,425.46	13,940	13,513	2,912	11.35	257
1933	5,702.07	4,818	4,670	1,032	11.63	89
1934	10,275.01	8,642	8,377	1,898	11.92	159
1935	7,275.96	6,091	5,904	1,371	12.21	112
1936	4,523.96	3,769	3,654	870	12.52	69
1937	9,372.98	7,770	7,532	1,841	12.83	143
1938	6,706.05	5,530	5,361	1,345	13.15	102
1939	15,778.35	12,943	12,547	3,232	13.48	240
1940	15,321.43	12,498	12,115	3,206	13.82	232
1941	28,581.36	23,181	22,471	6,110	14.17	431
1942	28,640.15	23,092	22,385	6,255	14.53	430
1943	4,086.55	3,275	3,175	912	14.90	61
1944	5,466.19	4,353	4,220	1,246	15.28	82
1945	9,459.21	7,483	7,254	2,205	15.67	141
1946	349,795.67	274,799	266,385	83,411	16.08	5,187
1947	56,220.97	43,860	42,517	13,704	16.49	831
1948	105,675.94	81,835	79,329	26,347	16.92	1,557
1949	121,980.78	93,746	90,876	31,105	17.36	1,792
1950	1,641,297.81	1,251,539	1,213,217	428,080	17.81	24,036
1951	356,012.23	269,288	261,043	94,970	18.27	5,198
1952	613,470.27	460,182	446,091	167,379	18.74	8,932
1953	708,423.35	526,784	510,654	197,769	19.23	10,284
1954	1,370,123.69	1,009,877	978,955	391,169	19.72	19,836
1955	1,174,541.09	857,732	831,469	343,073	20.23	16,959
1956	1,762,616.14	1,274,953	1,235,914	526,702	20.75	25,383
1957	1,501,549.82	1,075,515	1,042,583	458,967	21.28	21,568
1958	2,997,830.29	2,125,672	2,060,585	937,246	21.82	42,954
1959	1,764,715.08	1,238,124	1,200,213	564,502	22.38	25,224
1960	2,872,448.35	1,993,853	1,932,802	939,646	22.94	40,961
1961	1,676,944.17	1,151,272	1,116,020	560,924	23.51	23,859
1962	1,787,461.53	1,213,097	1,175,952	611,509	24.10	25,374
1963	2,236,108.47	1,499,982	1,454,053	782,055	24.69	31,675
1964	2,223,248.89	1,473,569	1,428,449	794,800	25.29	31,427

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1965	2,797,514.13	1,831,057	1,774,991	1,022,523	25.91	39,464
1966	2,974,334.23	1,922,223	1,863,365	1,110,969	26.53	41,876
1967	3,095,712.85	1,974,662	1,914,199	1,181,514	27.16	43,502
1968	3,477,602.46	2,188,560	2,121,547	1,356,055	27.80	48,779
1969	3,885,431.29	2,411,571	2,337,730	1,547,702	28.45	54,401
1970	3,273,314.65	2,002,843	1,941,517	1,331,798	29.11	45,751
1971	3,152,236.35	1,900,578	1,842,383	1,309,853	29.78	43,984
1972	3,033,976.31	1,802,182	1,747,000	1,286,976	30.45	42,265
1973	2,756,115.16	1,611,776	1,562,424	1,193,691	31.14	38,333
1974	3,062,174.01	1,762,587	1,708,617	1,353,557	31.83	42,525
1975	2,208,922.47	1,251,134	1,212,825	996,098	32.52	30,630
1976	1,942,498.17	1,081,836	1,048,711	893,788	33.23	26,897
1977	2,346,256.83	1,284,505	1,245,174	1,101,083	33.94	32,442
1978	2,057,923.24	1,106,895	1,073,002	984,921	34.66	28,417
1979	4,174,942.80	2,204,913	2,137,399	2,037,543	35.39	57,574
1980	8,504,909.80	4,407,840	4,272,874	4,232,036	36.13	117,134
1981	6,187,587.87	3,145,770	3,049,448	3,138,140	36.87	85,114
1982	6,752,567.44	3,826,005	3,708,854	3,043,713	33.08	92,011
1983	1,526,982.31	851,598	825,522	701,460	33.51	20,933
1984	2,221,241.47	1,209,466	1,172,433	1,048,809	34.51	30,391
1985	2,941,994.97	1,574,850	1,526,629	1,415,366	34.94	40,508
1986	4,744,328.34	2,495,517	2,419,105	2,325,223	35.37	65,740
1987	2,049,943.19	1,050,801	1,018,626	1,031,317	36.37	28,356
1988	4,133,865.39	2,078,921	2,015,265	2,118,600	36.82	57,539
1989	3,554,308.11	1,752,274	1,698,620	1,855,688	37.28	49,777
1990	3,292,738.12	1,578,539	1,530,205	1,762,533	38.28	46,043
1991	3,116,681.32	1,462,347	1,417,570	1,699,111	38.74	43,859
1992	2,412,605.72	1,106,904	1,073,011	1,339,595	39.22	34,156
1993	1,063,940.34	473,453	458,956	604,984	40.22	15,042
1994	868,141.87	377,121	365,574	502,568	40.69	12,351
1995	5,072,614.45	2,148,252	2,082,473	2,990,141	41.18	72,611
1996	4,909,090.15	2,010,272	1,948,718	2,960,372	42.18	70,184
1997	1,908,175.14	760,026	736,754	1,171,421	42.67	27,453
1998	2,317,905.41	897,029	869,562	1,448,343	43.17	33,550
1999	1,116,075.83	418,975	406,146	709,930	43.68	16,253
2000	2,556,980.59	923,326	895,054	1,661,926	44.68	37,196
2001	5,870,466.65	2,049,967	1,987,198	3,883,269	45.19	85,932
2002	1,049,992.56	353,952	343,114	706,878	45.72	15,461
2003	3,324,305.34	1,072,421	1,039,584	2,284,721	46.72	48,902
2004	1,751,054.17	543,177	526,545	1,224,509	47.25	25,916
2005	1,018,982.53	303,351	294,063	724,920	47.78	15,172

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2006	2,676,633.92	762,573	739,223	1,937,411	48.32	40,095
2007	882,469.49	238,355	231,057	651,413	49.32	13,208
2008	2,142,692.29	558,814	541,703	1,600,989	49.61	32,271
2009	2,496,256.14	617,823	598,905	1,897,351	50.17	37,818
2010	2,047,428.93	479,098	464,428	1,583,001	50.73	31,204
2011	1,838,964.34	402,733	390,401	1,448,563	51.72	28,008
2012	2,345,422.42	481,281	466,544	1,878,878	52.29	35,932
2013	3,396,529.84	649,417	629,532	2,766,998	52.86	52,346
2014	4,897,290.75	867,310	840,753	4,056,537	53.44	75,908
2015	9,548,185.76	1,554,445	1,506,848	8,041,337	54.01	148,886
2016	12,543,639.26	1,858,967	1,802,046	10,741,593	54.60	196,732
2017	23,573,103.17	3,144,652	3,048,364	20,524,739	55.20	371,825
2018	19,048,888.55	2,270,628	2,201,102	16,847,786	55.40	304,112
2019	10,579,885.38	1,100,308	1,066,617	9,513,268	56.00	169,880
2020	10,788,910.20	955,897	926,628	9,862,282	56.61	174,214
2021	24,375,021.21	1,789,127	1,734,345	22,640,677	56.85	398,253
2022	23,050,342.38	1,332,310	1,291,515	21,758,827	57.10	381,065
2023	26,753,261.60	1,123,637	1,089,232	25,664,030	57.02	450,088
2024	15,455,531.27	398,753	386,543	15,068,988	56.64	266,049
2025	21,644,324.90	196,963	190,932	21,453,393	54.45	394,002
	375,239,857.91	105,046,393	101,829,911	273,409,947		5,790,357
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1901	2,228.05	2,110	2,128	100	3.98	25
1903	551.10	518	522	29	4.51	6
1904	358.50	336	339	20	4.75	4
1905	1,654.35	1,544	1,557	97	5.00	19
1906	4,409.08	4,102	4,137	272	5.23	52
1907	11,153.26	10,341	10,430	724	5.46	133
1908	22,399.21	20,703	20,881	1,519	5.68	267
1909	460.40	424	428	33	5.91	6
1910	3,046.25	2,798	2,822	224	6.12	37
1911	5.83	5	5	1	6.34	
1913	2,389.75	2,174	2,193	197	6.77	29
1914	343.18	311	314	30	6.99	4
1916	14.29	13	13	1	7.44	
1920	4,915.09	4,369	4,406	509	8.34	61

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1921	37,757.51	33,438	33,725	4,033	8.58	470
1922	26,299.27	23,210	23,409	2,890	8.81	328
1923	35,985.14	31,643	31,914	4,071	9.05	450
1924	42,895.65	37,582	37,904	4,991	9.29	537
1925	44,602.85	38,935	39,269	5,334	9.53	560
1926	11,674.21	10,152	10,239	1,435	9.78	147
1927	30,400.95	26,335	26,561	3,840	10.03	383
1928	9,884.85	8,530	8,603	1,282	10.28	125
1929	835.02	718	724	111	10.54	11
1930	75,623.54	64,734	65,289	10,334	10.80	957
1931	213,212.82	181,743	183,302	29,911	11.07	2,702
1932	6,429.65	5,457	5,504	926	11.35	82
1933	11,189.08	9,454	9,535	1,654	11.63	142
1934	1,709.23	1,438	1,450	259	11.92	22
1935	2,433.53	2,037	2,054	379	12.21	31
1936	17,605.61	14,667	14,793	2,813	12.52	225
1937	3,851.45	3,193	3,220	631	12.83	49
1938	3,437.92	2,835	2,859	579	13.15	44
1939	1,769.83	1,452	1,464	305	13.48	23
1940	10,400.55	8,484	8,557	1,844	13.82	133
1941	1,412.00	1,145	1,155	257	14.17	18
1942	811.48	654	660	152	14.53	10
1944	463.83	369	372	92	15.28	6
1946	73,844.45	58,012	58,510	15,335	16.08	954
1947	15,125.48	11,800	11,901	3,224	16.49	196
1948	8,584.41	6,648	6,705	1,879	16.92	111
1949	12,988.45	9,982	10,068	2,921	17.36	168
1950	8,783.43	6,698	6,755	2,028	17.81	114
1951	13,305.34	10,064	10,150	3,155	18.27	173
1952	153,901.08	115,446	116,436	37,465	18.74	1,999
1953	341,194.90	253,713	255,889	85,306	19.23	4,436
1954	7,558.01	5,571	5,619	1,939	19.72	98
1955	105,235.77	76,851	77,510	27,726	20.23	1,371
1956	613,852.08	444,018	447,827	166,025	20.75	8,001
1957	1,594,496.20	1,142,090	1,151,887	442,610	21.28	20,799
1958	174,294.09	123,587	124,647	49,647	21.82	2,275
1959	1,095,276.95	768,446	775,038	320,239	22.38	14,309
1960	614,802.64	426,753	430,414	184,389	22.94	8,038
1961	1,232,965.25	846,468	853,729	379,236	23.51	16,131
1962	984,401.62	668,084	673,815	310,587	24.10	12,887
1963	1,754,555.09	1,176,956	1,187,052	567,503	24.69	22,985

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1964	2,916,715.53	1,933,199	1,949,781	966,934	25.29	38,234
1965	2,223,823.28	1,455,559	1,468,044	755,779	25.91	29,169
1966	1,956,094.36	1,264,165	1,275,009	681,086	26.53	25,672
1967	2,187,764.11	1,395,509	1,407,479	780,285	27.16	28,729
1968	3,304,609.17	2,079,690	2,097,529	1,207,080	27.80	43,420
1969	2,943,830.15	1,827,147	1,842,820	1,101,010	28.45	38,700
1970	2,430,248.10	1,486,996	1,499,751	930,497	29.11	31,965
1971	2,205,588.05	1,329,815	1,341,222	864,366	29.78	29,025
1972	3,245,868.41	1,928,046	1,944,584	1,301,284	30.45	42,735
1973	1,178,282.83	689,060	694,971	483,312	31.14	15,521
1974	544,897.57	313,643	316,333	228,564	31.83	7,181
1975	607,131.78	343,879	346,829	260,303	32.52	8,004
1976	409,665.88	228,155	230,112	179,554	33.23	5,403
1977	611,909.55	335,002	337,876	274,034	33.94	8,074
1978	580,670.27	312,325	315,004	265,666	34.66	7,665
1979	1,015,825.10	536,488	541,090	474,735	35.39	13,414
1980	962,976.53	499,082	503,363	459,614	36.13	12,721
1981	2,989,830.03	1,520,030	1,533,068	1,456,762	36.87	39,511
1982	4,664,574.41	2,642,948	2,665,618	1,998,956	33.08	60,428
1983	447,750.15	249,710	251,852	195,898	33.51	5,846
1984	1,527,801.92	831,888	839,024	688,778	34.51	19,959
1985	1,499,956.68	802,927	809,814	690,142	34.94	19,752
1986	1,335,793.43	702,627	708,654	627,139	35.37	17,731
1987	1,652,651.26	847,149	854,416	798,236	36.37	21,948
1988	1,755,837.98	883,011	890,585	865,253	36.82	23,500
1989	1,567,155.86	772,608	779,235	787,921	37.28	21,135
1990	1,296,148.55	621,374	626,704	669,445	38.28	17,488
1991	832,465.18	390,593	393,943	438,522	38.74	11,320
1992	2,818,493.78	1,293,125	1,304,217	1,514,277	39.22	38,610
1993	859,192.37	382,341	385,621	473,572	40.22	11,775
1994	1,531,194.04	665,151	670,856	860,338	40.69	21,144
1995	1,210,666.83	512,717	517,115	693,552	41.18	16,842
1996	8,853,784.25	3,625,625	3,656,725	5,197,060	42.18	123,211
1997	7,727,774.16	3,077,972	3,104,374	4,623,400	42.67	108,352
1998	3,538,930.75	1,369,566	1,381,314	2,157,617	43.17	49,980
1999	442,805.93	166,229	167,655	275,151	43.68	6,299
2000	8,110,526.11	2,928,711	2,953,833	5,156,693	44.68	115,414
2001	2,138,117.19	746,631	753,035	1,385,082	45.19	30,650
2002	5,035,598.24	1,697,500	1,712,061	3,323,538	45.72	72,693
2003	2,489,177.65	803,009	809,897	1,679,281	46.72	35,944
2004	2,650,830.47	822,288	829,341	1,821,489	47.25	38,550

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2005	2,724,517.60	811,089	818,046	1,906,471	47.78	39,901
2006	1,311,491.42	373,644	376,849	934,642	48.32	19,343
2007	914,328.73	246,960	249,078	665,250	49.32	13,488
2008	2,782,720.98	725,734	731,959	2,050,762	49.61	41,338
2009	550,585.12	136,270	137,439	413,146	50.17	8,235
2010	2,404,204.56	562,584	567,410	1,836,795	50.73	36,207
2011	1,323,738.90	289,899	292,386	1,031,353	51.72	19,941
2012	2,644,697.85	542,692	547,347	2,097,351	52.29	40,110
2013	4,760,365.28	910,182	917,989	3,842,376	52.86	72,690
2014	15,649,238.11	2,771,480	2,795,253	12,853,985	53.44	240,531
2015	16,466,229.15	2,680,702	2,703,696	13,762,533	54.01	254,815
2016	11,970,753.94	1,774,066	1,789,283	10,181,471	54.60	186,474
2017	7,086,089.47	945,284	953,392	6,132,697	55.20	111,100
2018	60,926,631.53	7,262,454	7,324,749	53,601,882	55.40	967,543
2019	7,284,170.98	757,554	764,052	6,520,119	56.00	116,431
2020	9,051,292.25	801,944	808,823	8,242,469	56.61	145,601
2021	3,418,593.84	250,925	253,077	3,165,516	56.85	55,682
2022	7,431,380.76	429,534	433,218	6,998,162	57.10	122,560
2023	9,786,110.04	411,017	414,543	9,371,567	57.02	164,356
2024	3,835,370.12	98,953	99,802	3,735,568	56.64	65,953
2025	4,777,512.60	43,475	43,848	4,733,665	54.45	86,936
	282,852,760.67	75,849,072	76,499,684	206,353,077		4,246,092
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1903	583.13	548	583			
1906	158.56	148	159			
1908	16.94	16	17			
1909	59.38	55	59			
1910	474.52	436	475			
1911	4.16	4	4			
1912	75.53	69	76			
1913	941.60	857	942			
1915	258.93	234	258	1	7.22	
1916	85.45	77	85	1	7.44	
1918	100.00	89	98	2	7.89	
1919	146.35	131	144	2	8.11	
1921	55.23	49	54	1	8.58	

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1923	9,519.11	8,370	9,230	289	9.05	32
1924	615.15	539	594	21	9.29	2
1925	6,283.14	5,485	6,049	235	9.53	25
1926	4,581.08	3,984	4,393	188	9.78	19
1927	8,190.86	7,095	7,824	367	10.03	37
1928	26,201.23	22,610	24,933	1,268	10.28	123
1929	83.58	72	79	4	10.54	
1930	197.44	169	186	11	10.80	1
1931	5.86	5	6			
1932	56,310.34	47,789	52,699	3,611	11.35	318
1933	178.90	151	167	12	11.63	1
1934	9.92	8	9	1	11.92	
1935	88.50	74	82	7	12.21	1
1936	602.04	502	554	48	12.52	4
1937	1.18	1	1			
1938	77.09	64	71	7	13.15	1
1939	5,290.28	4,339	4,785	505	13.48	37
1940	3,133.75	2,556	2,819	315	13.82	23
1941	39,890.95	32,354	35,678	4,213	14.17	297
1942	293.84	237	261	32	14.53	2
1943	1,830.05	1,466	1,617	213	14.90	14
1944	6,105.49	4,862	5,362	744	15.28	49
1945	330.51	261	288	43	15.67	3
1946	8,847.37	6,950	7,664	1,183	16.08	74
1947	9,495.33	7,408	8,169	1,326	16.49	80
1948	3,810.15	2,951	3,254	556	16.92	33
1949	88,189.17	67,776	74,740	13,449	17.36	775
1951	20,806.11	15,738	17,355	3,451	18.27	189
1952	2,875.35	2,157	2,379	497	18.74	27
1953	32,287.32	24,009	26,476	5,811	19.23	302
1954	24,778.86	18,264	20,141	4,638	19.72	235
1955	11,336.59	8,279	9,130	2,207	20.23	109
1956	41,421.03	29,961	33,039	8,382	20.75	404
1957	54,569.44	39,086	43,102	11,467	21.28	539
1958	17,486.03	12,399	13,673	3,813	21.82	175
1959	60,072.43	42,147	46,478	13,595	22.38	607
1960	52,283.75	36,292	40,021	12,263	22.94	535
1961	143,608.66	98,592	108,722	34,886	23.51	1,484
1962	220,608.97	149,721	165,105	55,504	24.10	2,303
1963	450,258.10	302,033	333,066	117,192	24.69	4,747
1964	487,963.98	323,423	356,654	131,310	25.29	5,192

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1965	340,832.23	223,085	246,007	94,826	25.91	3,660
1966	713,438.52	461,074	508,449	204,990	26.53	7,727
1967	308,779.02	196,961	217,198	91,581	27.16	3,372
1968	544,819.99	342,872	378,102	166,718	27.80	5,997
1969	453,146.42	281,254	310,152	142,994	28.45	5,026
1970	346,667.58	212,115	233,909	112,758	29.11	3,874
1971	273,042.91	164,626	181,541	91,502	29.78	3,073
1972	159,947.59	95,009	104,771	55,177	30.45	1,812
1973	325,767.38	190,509	210,083	115,684	31.14	3,715
1974	314,334.42	180,931	199,521	114,813	31.83	3,607
1975	111,588.03	63,203	69,697	41,891	32.52	1,288
1976	263,099.47	146,528	161,584	101,516	33.23	3,055
1977	120,745.44	66,105	72,897	47,848	33.94	1,410
1978	356,689.91	191,853	211,566	145,124	34.66	4,187
1979	158,751.97	83,842	92,457	66,295	35.39	1,873
1980	219,162.71	113,585	125,256	93,907	36.13	2,599
1981	224,528.56	114,150	125,879	98,650	36.87	2,676
1982	234,052.78	132,614	146,240	87,813	33.08	2,655
1983	353,108.49	196,929	217,163	135,945	33.51	4,057
1984	137,400.21	74,814	82,501	54,899	34.51	1,591
1985	400,453.81	214,363	236,388	164,065	34.94	4,696
1986	641,082.05	337,209	371,857	269,225	35.37	7,612
1987	121,537.00	62,300	68,701	52,836	36.37	1,453
1988	168,762.62	84,871	93,591	75,171	36.82	2,042
1989	381,905.73	188,280	207,625	174,280	37.28	4,675
1990	82,807.78	39,698	43,777	39,031	38.28	1,020
1991	534,685.46	250,874	276,651	258,035	38.74	6,661
1992	1,299,453.53	596,189	657,446	642,007	39.22	16,369
1993	621,169.88	276,421	304,823	316,347	40.22	7,865
1995	954.52	404	446	509	41.18	12
1996	641,715.55	262,783	289,784	351,932	42.18	8,344
1997	676,730.08	269,542	297,237	379,493	42.67	8,894
1998	953,126.63	368,860	406,760	546,367	43.17	12,656
1999	349,130.34	131,064	144,531	204,600	43.68	4,684
2000	3,613,421.29	1,304,806	1,438,873	2,174,549	44.68	48,669
2001	406,639.77	141,999	156,589	250,051	45.19	5,533
2002	1,545,609.94	521,025	574,559	971,050	45.72	21,239
2003	341,151.07	110,055	121,363	219,788	46.72	4,704
2004	4,206,022.68	1,304,708	1,438,765	2,767,258	47.25	58,566
2005	6,357,629.75	1,892,666	2,087,134	4,270,495	47.78	89,378
2006	2,587,119.70	737,070	812,803	1,774,317	48.32	36,720

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2007	1,041,492.17	281,307	310,211	731,281	49.32	14,827
2008	148,227.68	38,658	42,630	105,598	49.61	2,129
2009	3,189,007.87	789,279	870,376	2,318,632	50.17	46,216
2010	952,964.75	222,994	245,906	707,058	50.73	13,938
2011	2,259,063.89	494,735	545,568	1,713,496	51.72	33,130
2012	504,205.01	103,463	114,094	390,111	52.29	7,461
2013	945,363.74	180,754	199,326	746,038	52.86	14,113
2014	488,857.58	86,577	95,473	393,385	53.44	7,361
2015	2,328,644.91	379,103	418,055	1,910,590	54.01	35,375
2016	9,569,265.35	1,418,165	1,563,879	8,005,386	54.60	146,619
2017	7,607,601.83	1,014,854	1,119,129	6,488,473	55.20	117,545
2018	5,200,330.17	619,879	683,571	4,516,760	55.40	81,530
2019	4,122,032.64	428,691	472,738	3,649,294	56.00	65,166
2020	12,088,916.03	1,071,078	1,181,129	10,907,787	56.61	192,683
2021	3,984,186.41	292,439	322,487	3,661,700	56.85	64,410
2022	7,580,288.60	438,141	483,159	7,097,129	57.10	124,293
2023	1,595,201.32	66,998	73,882	1,521,319	57.02	26,680
2024	5,560,873.15	143,471	158,212	5,402,661	56.64	95,386
2025	437,103.09	3,978	4,387	432,716	54.45	7,947
	103,398,117.71	22,034,702	24,298,693	79,099,425		1,534,654
	761,490,736.29	202,930,167	202,628,288	558,862,449		11,571,103

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.3 1.52

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1901	665.32	651	631	34	1.44	24
1902	1,876.45	1,833	1,777	100	1.51	66
1903	661.31	645	625	36	1.56	23
1904	1,470.23	1,434	1,390	80	1.61	50
1905	930.38	907	879	51	1.64	31
1906	1,039.29	1,013	982	57	1.66	34
1907	1,672.43	1,629	1,579	93	1.68	55
1908	4,594.00	4,474	4,337	257	1.70	151
1909	1,516.23	1,476	1,431	85	1.72	49
1910	781.01	760	737	44	1.73	25
1911	3,276.38	3,188	3,090	186	1.75	106
1912	2,805.58	2,729	2,645	160	1.76	91
1913	870.86	847	821	50	1.77	28
1914	3,083.63	2,999	2,907	176	1.78	99
1915	3,725.15	3,622	3,511	214	1.79	120
1916	2,084.30	2,026	1,964	120	1.80	67
1917	2,302.84	2,238	2,169	133	1.81	73
1918	1,613.19	1,568	1,520	93	1.82	51
1919	5,743.39	5,581	5,410	333	1.83	182
1920	5,437.10	5,283	5,121	316	1.83	173
1921	2,270.62	2,206	2,138	132	1.84	72
1922	33,123.16	32,170	31,185	1,938	1.85	1,048
1923	7,935.08	7,706	7,470	465	1.85	251
1924	36,316.13	35,262	34,182	2,134	1.86	1,147
1925	7,038.34	6,834	6,625	414	1.86	223
1926	16,015.63	15,547	15,071	945	1.87	505
1927	19,332.45	18,765	18,190	1,142	1.87	611
1928	14,711.22	14,276	13,839	872	1.88	464
1929	22,640.69	21,970	21,297	1,343	1.88	714
1930	11,103.53	10,772	10,442	661	1.89	350
1931	3,414.62	3,312	3,211	204	1.89	108
1932	1,643.47	1,594	1,545	98	1.89	52
1933	93.97	91	88	6	1.90	3
1934	201.46	195	189	12	1.90	6
1935	1,404.76	1,362	1,320	84	1.90	44
1936	2,219.81	2,152	2,086	134	1.91	70
1937	1,507.39	1,461	1,416	91	1.91	48
1938	1,013.48	982	952	62	1.91	32
1939	4,543.85	4,402	4,267	277	1.92	144
1940	3,443.16	3,335	3,233	210	1.92	109

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1941	6,305.26	6,107	5,920	385	1.92	201
1942	455.82	441	427	28	1.92	15
1943	1,059.36	1,025	994	66	1.93	34
1944	2,021.15	1,956	1,896	125	1.93	65
1945	233.29	226	219	14	1.93	7
1946	3,466.43	3,354	3,251	215	1.93	111
1947	4,534.23	4,385	4,251	283	1.94	146
1948	13,944.47	13,484	13,071	873	1.94	450
1949	14,981.32	14,483	14,040	942	1.94	486
1950	9,771.29	9,444	9,155	616	1.94	318
1951	14,464.65	13,977	13,549	916	1.94	472
1952	19,332.52	18,677	18,105	1,227	1.94	632
1953	13,918.64	13,441	13,029	889	1.95	456
1954	23,732.78	22,911	22,209	1,523	1.95	781
1955	45,943.45	44,341	42,983	2,960	1.95	1,518
1956	22,722.46	21,923	21,252	1,471	1.95	754
1957	31,202.14	30,096	29,174	2,028	1.95	1,040
1958	12,729.72	12,274	11,898	832	1.95	427
1959	34,438.45	33,196	32,180	2,259	1.95	1,158
1960	5,230.46	5,039	4,885	346	1.96	177
1962	3,625.02	3,490	3,383	242	1.96	123
1968	316.24	304	295	22	1.97	11
2025	30,687.51	6,205	6,015	24,673	1.97	12,524
	551,238.55	510,076	494,458	56,781		29,405
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1903	827.90	808	815	13	1.56	8
1904	1,600.92	1,561	1,574	27	1.61	17
1905	59.45	58	58	1	1.64	1
1906	3,388.02	3,301	3,329	59	1.66	36
1908	45.16	44	44	1	1.70	1
1910	2,040.42	1,986	2,003	37	1.73	21
1911	13,104.26	12,751	12,860	244	1.75	139
1912	4,993.79	4,858	4,900	94	1.76	53

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1923	297.99	289	291	7	1.85	4
1943	508.36	492	496	12	1.93	6
1952	86,661.17	83,721	84,439	2,222	1.94	1,145
	113,527.44	109,869	110,811	2,716		1,431
	664,765.99	619,945	605,269	59,497		30,836

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.9 4.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1972	23,054.83	15,555	15,079	7,976	22.12	361
1973	52,646.57	35,010	33,938	18,709	22.78	821
1974	12,648.66	8,285	8,031	4,617	23.46	197
1975	44,844.46	28,918	28,033	16,812	24.15	696
1976	461,953.69	293,137	284,161	177,792	24.85	7,155
1977	472,283.71	294,828	285,800	186,483	25.55	7,299
1978	680,937.03	417,877	405,082	275,855	26.27	10,501
1979	527,971.23	318,335	308,588	219,384	27.00	8,125
1980	1,132,533.24	670,698	650,161	482,372	27.73	17,395
1981	1,466,339.21	852,207	826,113	640,226	28.48	22,480
1982	2,002,821.21	1,247,357	1,209,163	793,658	26.19	30,304
1983	2,424,124.04	1,485,018	1,439,547	984,577	26.72	36,848
1984	3,320,390.53	1,985,926	1,925,118	1,395,273	27.72	50,335
1985	3,509,898.36	2,062,416	1,999,266	1,510,633	28.25	53,474
1986	4,367,095.46	2,519,814	2,442,658	1,924,437	28.78	66,867
1987	7,640,059.83	4,296,006	4,164,464	3,475,596	29.78	116,709
1988	10,914,047.49	6,016,914	5,832,678	5,081,369	30.32	167,591
1989	13,250,594.24	7,156,646	6,937,512	6,313,082	30.87	204,505
1990	15,068,732.14	7,914,098	7,671,771	7,396,961	31.87	232,098
1991	9,063,229.36	4,656,687	4,514,101	4,549,128	32.41	140,362
1992	7,050,159.96	3,539,885	3,431,495	3,618,665	32.97	109,756
1993	5,238,952.15	2,568,134	2,489,499	2,749,453	33.54	81,975
1994	9,502,539.50	4,513,706	4,375,498	5,127,042	34.54	148,438
1995	15,259,193.47	7,061,955	6,845,721	8,413,473	35.11	239,632
1996	9,163,159.70	4,100,514	3,974,958	5,188,202	36.11	143,678
1997	14,125,837.91	6,144,739	5,956,589	8,169,249	36.69	222,656
1998	9,962,734.31	4,208,259	4,079,404	5,883,331	37.26	157,899
1999	10,493,923.34	4,269,977	4,139,232	6,354,691	38.26	166,092
2000	10,948,523.74	4,312,624	4,180,573	6,767,951	38.85	174,207
2001	11,038,450.29	4,202,338	4,073,664	6,964,786	39.45	176,547
2002	10,197,873.40	3,722,224	3,608,251	6,589,623	40.45	162,908
2003	14,300,294.12	5,027,983	4,874,028	9,426,266	41.04	229,685
2004	13,334,281.61	4,477,652	4,340,548	8,993,734	42.04	213,933
2005	14,320,883.98	4,611,325	4,470,128	9,850,756	42.64	231,021
2006	15,003,855.91	4,592,680	4,452,054	10,551,802	43.64	241,792
2007	14,151,643.32	4,132,280	4,005,751	10,145,892	44.25	229,286
2008	11,833,408.37	3,313,354	3,211,900	8,621,508	45.00	191,589
2009	11,358,432.75	3,016,800	2,924,427	8,434,006	45.61	184,916
2010	11,857,384.27	2,977,389	2,886,222	8,971,162	46.23	194,055
2011	16,700,544.44	3,922,958	3,802,838	12,897,706	47.23	273,083
2012	22,340,879.43	4,914,993	4,764,498	17,576,382	47.85	367,323

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2013	29,855,934.40	6,084,639	5,898,330	23,957,605	48.85	490,432
2014	33,122,689.45	6,246,939	6,055,660	27,067,029	49.48	547,030
2015	31,441,973.88	5,414,308	5,248,524	26,193,450	50.48	518,888
2016	43,922,801.81	6,887,095	6,676,215	37,246,587	51.10	728,896
2017	39,471,173.42	5,533,859	5,364,414	34,106,759	52.11	654,515
2018	51,383,538.12	6,397,250	6,201,369	45,182,170	52.74	856,696
2019	71,517,687.98	7,766,821	7,529,004	63,988,684	53.38	1,198,739
2020	79,221,639.35	7,272,546	7,049,863	72,171,776	54.38	1,327,175
2021	88,047,499.52	6,656,391	6,452,575	81,594,925	55.02	1,483,005
2022	108,438,099.94	6,419,536	6,222,972	102,215,128	55.67	1,836,090
2023	129,150,040.75	5,488,877	5,320,810	123,829,231	56.32	2,198,672
2024	101,389,109.75	2,595,561	2,516,086	98,873,024	56.98	1,735,223
2025	117,456,950.04	1,021,875	990,586	116,466,364	56.97	2,044,346
	1,259,038,299.67	205,693,198	199,394,947	1,059,643,352		20,934,301
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1973	290,280.03	193,036	194,692	95,588	22.78	4,196
1974	579,124.32	379,326	382,580	196,545	23.46	8,378
1975	1,605,904.83	1,035,568	1,044,450	561,454	24.15	23,249
1976	1,095,423.94	695,112	701,074	394,350	24.85	15,869
1977	1,350,958.02	843,349	850,583	500,375	25.55	19,584
1978	1,726,649.21	1,059,610	1,068,699	657,951	26.27	25,046
1979	1,948,169.09	1,174,629	1,184,704	763,465	27.00	28,276
1980	2,092,521.20	1,239,212	1,249,841	842,680	27.73	30,389
1981	1,522,689.50	884,957	892,548	630,142	28.48	22,126
1982	1,543,235.48	961,127	969,371	573,865	26.19	21,912
1983	811,337.73	497,025	501,288	310,050	26.72	11,604
1984	1,014,038.88	606,497	611,699	402,340	27.72	14,514
1985	1,299,517.77	763,597	770,147	529,371	28.25	18,739
1986	1,977,583.02	1,141,065	1,150,852	826,731	28.78	28,726
1987	3,204,490.23	1,801,885	1,817,340	1,387,150	29.78	46,580
1988	5,835,270.15	3,216,984	3,244,577	2,590,693	30.32	85,445
1989	4,293,067.06	2,318,686	2,338,574	1,954,493	30.87	63,314
1990	4,757,446.54	2,498,611	2,520,042	2,237,404	31.87	70,204
1991	2,205,471.26	1,133,171	1,142,891	1,062,581	32.41	32,786
1992	2,733,486.23	1,372,483	1,384,255	1,349,231	32.97	40,923
1993	2,633,746.10	1,291,062	1,302,136	1,331,610	33.54	39,702

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1994	5,317,507.87	2,525,816	2,547,481	2,770,027	34.54	80,198
1995	5,579,518.88	2,582,201	2,604,349	2,975,170	35.11	84,739
1996	6,504,900.92	2,910,943	2,935,911	3,568,990	36.11	98,837
1997	9,967,331.34	4,335,789	4,372,978	5,594,353	36.69	152,476
1998	7,438,860.40	3,142,175	3,169,126	4,269,734	37.26	114,593
1999	5,221,803.07	2,124,752	2,142,977	3,078,826	38.26	80,471
2000	4,069,860.23	1,603,118	1,616,868	2,452,992	38.85	63,140
2001	7,101,942.73	2,703,710	2,726,901	4,375,042	39.45	110,901
2002	3,175,838.76	1,159,181	1,169,124	2,006,715	40.45	49,610
2003	3,588,415.04	1,261,687	1,272,509	2,315,906	41.04	56,430
2004	8,105,046.24	2,721,675	2,745,020	5,360,027	42.04	127,498
2005	6,603,258.45	2,126,249	2,144,487	4,458,772	42.64	104,568
2006	3,981,254.78	1,218,662	1,229,115	2,752,140	43.64	63,065
2007	5,612,897.22	1,638,966	1,653,024	3,959,873	44.25	89,489
2008	4,659,907.46	1,304,774	1,315,965	3,343,942	45.00	74,310
2009	5,590,409.78	1,484,813	1,497,549	4,092,861	45.61	89,736
2010	4,091,931.61	1,027,484	1,036,297	3,055,635	46.23	66,096
2011	5,588,116.08	1,312,648	1,323,907	4,264,209	47.23	90,286
2012	8,827,627.50	1,942,078	1,958,736	6,868,892	47.85	143,551
2013	5,530,661.71	1,127,149	1,136,817	4,393,845	48.85	89,946
2014	8,079,206.43	1,523,738	1,536,808	6,542,399	49.48	132,223
2015	15,571,691.96	2,681,445	2,704,445	12,867,247	50.48	254,898
2016	18,105,563.27	2,838,952	2,863,303	15,242,261	51.10	298,283
2017	21,020,709.76	2,947,104	2,972,382	18,048,328	52.11	346,351
2018	22,655,048.38	2,820,554	2,844,747	19,810,302	52.74	375,622
2019	28,522,567.96	3,097,551	3,124,120	25,398,448	53.38	475,805
2020	26,700,530.69	2,451,109	2,472,133	24,228,398	54.38	445,539
2021	24,405,343.34	1,845,044	1,860,870	22,544,474	55.02	409,751
2022	32,690,535.42	1,935,280	1,951,880	30,738,656	55.67	552,158
2023	32,088,246.40	1,363,750	1,375,447	30,712,799	56.32	545,327
2024	22,702,922.20	581,195	586,180	22,116,742	56.98	388,149
2025	22,685,183.74	197,361	199,054	22,486,130	56.97	394,701
	436,305,050.21	89,643,945	90,412,849	345,892,201		7,100,309
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1966	7.46	5	6	2	18.36	
1967	6,583.70	4,748	5,236	1,348	18.96	71

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
1968	13,357.68	9,515	10,493	2,865	19.56	146
1969	7,310.82	5,140	5,668	1,643	20.19	81
1970	26,751.63	18,561	20,468	6,284	20.82	302
1971	375,873.37	257,251	283,683	92,191	21.46	4,296
1972	567,307.30	382,768	422,096	145,211	22.12	6,565
1973	441,598.79	293,663	323,836	117,763	22.78	5,170
1974	663,021.92	434,279	478,900	184,122	23.46	7,848
1975	590,110.57	380,533	419,631	170,479	24.15	7,059
1976	363,578.67	230,712	254,417	109,162	24.85	4,393
1977	664,472.47	414,804	457,424	207,049	25.55	8,104
1978	548,693.35	336,722	371,319	177,374	26.27	6,752
1979	506,056.32	305,122	336,472	169,584	27.00	6,281
1980	731,682.64	433,310	477,831	253,852	27.73	9,154
1981	856,365.99	497,703	548,840	307,526	28.48	10,798
1982	771,892.54	480,735	530,129	241,764	26.19	9,231
1983	894,656.44	548,067	604,379	290,277	26.72	10,864
1984	1,428,081.00	854,135	941,894	486,187	27.72	17,539
1985	1,622,455.27	953,355	1,051,309	571,146	28.25	20,218
1986	1,916,781.75	1,105,983	1,219,619	697,163	28.78	24,224
1987	1,463,966.29	823,188	907,768	556,199	29.78	18,677
1988	2,141,706.63	1,180,723	1,302,038	839,668	30.32	27,694
1989	2,204,596.90	1,190,703	1,313,044	891,553	30.87	28,881
1990	2,325,536.69	1,221,372	1,346,864	978,673	31.87	30,708
1991	2,677,870.99	1,375,890	1,517,258	1,160,613	32.41	35,810
1992	2,195,623.32	1,102,422	1,215,692	979,931	32.97	29,722
1993	3,430,483.75	1,681,623	1,854,404	1,576,080	33.54	46,991
1994	3,491,635.47	1,658,527	1,828,935	1,662,700	34.54	48,138
1995	3,858,993.28	1,785,942	1,969,441	1,889,552	35.11	53,818
1996	4,774,345.77	2,136,520	2,356,040	2,418,306	36.11	66,971
1997	4,912,561.78	2,136,964	2,356,530	2,556,032	36.69	69,666
1998	5,725,814.79	2,418,584	2,667,085	3,058,730	37.26	82,092
1999	3,407,045.81	1,386,327	1,528,767	1,878,278	38.26	49,092
2000	4,963,296.21	1,955,042	2,155,916	2,807,380	38.85	72,262
2001	2,515,338.68	957,589	1,055,978	1,459,361	39.45	36,993
2002	4,159,141.34	1,518,087	1,674,065	2,485,076	40.45	61,436
2003	4,419,998.48	1,554,071	1,713,746	2,706,252	41.04	65,942
2004	4,636,949.86	1,557,088	1,717,073	2,919,876	42.04	69,455
2005	4,746,834.86	1,528,481	1,685,527	3,061,308	42.64	71,794
2006	6,367,980.58	1,949,239	2,149,517	4,218,464	43.64	96,665
2007	5,431,491.95	1,585,996	1,748,952	3,682,540	44.25	83,221
2008	4,902,125.98	1,372,595	1,513,624	3,388,502	45.00	75,300

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 68-R3						
NET SALVAGE PERCENT.. 0						
2009	4,339,584.70	1,152,594	1,271,019	3,068,566	45.61	67,278
2010	6,209,619.02	1,559,235	1,719,441	4,490,178	46.23	97,127
2011	7,186,786.31	1,688,176	1,861,630	5,325,156	47.23	112,749
2012	5,196,175.59	1,143,159	1,260,615	3,935,561	47.85	82,248
2013	5,532,307.93	1,127,484	1,243,329	4,288,979	48.85	87,799
2014	7,540,947.58	1,422,223	1,568,352	5,972,596	49.48	120,707
2015	14,023,885.62	2,414,913	2,663,037	11,360,849	50.48	225,056
2016	12,514,157.10	1,962,220	2,163,831	10,350,326	51.10	202,550
2017	12,716,689.91	1,782,880	1,966,065	10,750,625	52.11	206,306
2018	16,664,225.90	2,074,696	2,287,864	14,376,362	52.74	272,589
2019	7,837,758.23	851,181	938,637	6,899,121	53.38	129,245
2020	4,761,041.54	437,064	481,971	4,279,071	54.38	78,688
2021	11,473,786.34	867,418	956,542	10,517,244	55.02	191,153
2022	15,256,990.51	903,214	996,016	14,260,974	55.67	256,170
2023	18,777,208.82	798,031	880,026	17,897,183	56.32	317,777
2024	21,564,045.93	552,040	608,760	20,955,286	56.98	367,766
2025	23,705,081.99	206,234	227,424	23,477,658	56.97	412,106
	293,050,272.11	62,966,846	69,436,475	223,613,797		4,607,738
	1,988,393,621.99	358,303,989	359,244,272	1,629,149,350		32,642,348
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					49.9	1.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1901	1,823.44	1,684	1,632	191	5.34	36
1902	858.12	789	765	93	5.63	17
1903	2,783.58	2,548	2,470	314	5.92	53
1904	6,859.36	6,253	6,062	798	6.19	129
1905	2,828.98	2,568	2,489	340	6.46	53
1906	4,634.90	4,190	4,062	573	6.72	85
1907	3,011.94	2,712	2,629	383	6.96	55
1908	6,470.50	5,805	5,627	843	7.20	117
1909	6,566.28	5,869	5,689	877	7.43	118
1910	8,992.96	8,008	7,763	1,230	7.66	161
1911	19,368.44	17,190	16,664	2,705	7.87	344
1912	12,488.38	11,044	10,706	1,783	8.09	220
1913	19,952.20	17,587	17,048	2,904	8.29	350
1914	52,379.23	46,019	44,610	7,769	8.49	915
1915	24,228.79	21,217	20,567	3,661	8.69	421
1916	19,636.02	17,140	16,615	3,021	8.88	340
1917	3,879.82	3,377	3,274	606	9.06	67
1918	4,097.87	3,555	3,446	652	9.24	71
1919	5,274.03	4,562	4,422	852	9.42	90
1920	2,322.08	2,003	1,942	380	9.59	40
1921	9,356.23	8,047	7,801	1,556	9.75	160
1922	14,230.62	12,206	11,832	2,398	9.91	242
1923	14,826.56	12,681	12,293	2,534	10.07	252
1924	43,133.11	36,793	35,666	7,467	10.22	731
2025	4,827.55	172	167	4,661	13.51	345
	294,830.99	254,019	246,241	48,590		5,412
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,183.84	1,079	1,088	96	6.19	16
1906	505.47	457	461	45	6.72	7
1911	733.05	651	657	77	7.87	10
1912	2,886.54	2,553	2,575	312	8.09	39
1914	339.20	298	301	39	8.49	5
1915	4,350.95	3,810	3,842	509	8.69	59
1916	121.20	106	107	14	8.88	2

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1924	17.25	15	15	2	10.22	
1928	52.02	44	44	8	10.78	1
1939	125.74	103	104	22	12.04	2
1940	30.00	25	25	5	12.14	
1943	25.03	20	20	5	12.42	
	10,370.29	9,161	9,239	1,131		141
	305,201.28	263,180	255,480	49,721		5,553

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.0 1.82

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	148,735	267,172	1,054,916	35.50	29,716
	1,322,088.00	148,735	267,172	1,054,916		29,716

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.5 2.25

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	60.11	60	60			
1916	181.38	181	181			
1919	866.04	866	866			
1920	206.24	206	206			
1921	61.35	61	61			
1923	344.32	344	344			
1924	964.73	965	965			
1926	1,128.81	1,129	1,129			
1927	2,475.31	2,475	2,475			
1928	46.54	47	47			
1929	648.47	648	648			
1930	760.31	756	760			
1931	2,359.80	2,328	2,360			
1935	52.66	50	53			
1936	389.94	370	390			
1937	1,324.03	1,245	1,324			
1940	177.98	163	176	2	3.97	1
1941	67.66	62	67	1	4.35	
1942	2,251.19	2,029	2,195	57	4.73	12
1943	951.02	850	919	32	5.10	6
1945	662.30	581	628	34	5.86	6
1946	836.20	727	786	50	6.25	8
1947	2,582.50	2,226	2,408	175	6.63	26
1948	1,731.51	1,478	1,599	133	7.02	19
1949	1,284.38	1,086	1,175	110	7.40	15
1950	12,348.68	10,345	11,189	1,159	7.79	149
1951	9,097.79	7,547	8,163	935	8.18	114
1952	18,233.00	14,978	16,201	2,032	8.57	237
1953	16,010.31	13,022	14,085	1,925	8.96	215
1954	58,460.58	47,061	50,903	7,558	9.36	807
1955	21,916.49	17,465	18,891	3,026	9.75	310
1956	93,634.68	73,835	79,862	13,772	10.15	1,357
1957	22,718.71	17,725	19,172	3,547	10.55	336
1958	34,439.52	26,583	28,753	5,686	10.95	519
1959	4,247.36	3,243	3,508	740	11.35	65
1960	30,885.78	23,319	25,223	5,663	11.76	482
1961	35,479.51	26,491	28,654	6,826	12.16	561
1962	39,510.06	29,163	31,544	7,966	12.57	634
1963	23,683.58	17,279	18,690	4,994	12.98	385
1964	17,515.14	12,625	13,656	3,860	13.40	288
1965	12,598.78	8,974	9,707	2,892	13.81	209

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1966	23,234.84	16,347	17,681	5,553	14.23	390
1967	50,058.92	34,780	37,619	12,440	14.65	849
1968	37,129.12	25,472	27,551	9,578	15.07	636
1969	26,218.37	17,757	19,207	7,012	15.49	453
1970	35,888.36	23,985	25,943	9,945	15.92	625
1971	179,160.05	118,135	127,779	51,381	16.35	3,143
1972	52,486.52	34,138	36,925	15,562	16.78	927
1973	11,695.29	7,502	8,114	3,581	17.21	208
1974	61,322.33	38,773	41,938	19,384	17.65	1,098
1975	44,847.84	27,946	30,227	14,621	18.09	808
1976	70,074.81	43,023	46,535	23,540	18.53	1,270
1977	29,085.96	17,591	19,027	10,059	18.97	530
1978	35,308.33	21,023	22,739	12,569	19.42	647
1979	33,031.61	19,358	20,938	12,093	19.87	609
1980	104,150.59	60,039	64,940	39,210	20.33	1,929
1981	179,956.67	102,050	110,381	69,576	20.78	3,348
1982	171,508.31	120,159	129,968	41,540	18.48	2,248
1983	36,280.59	25,139	27,191	9,089	18.73	485
1984	82,719.21	56,299	60,895	21,824	19.36	1,127
1985	182,636.27	122,768	132,790	49,846	19.63	2,539
1986	198,465.24	131,642	142,388	56,077	19.92	2,815
1987	148,175.08	96,921	104,833	43,342	20.23	2,142
1988	156,311.04	100,727	108,950	47,361	20.55	2,305
1989	338,101.06	214,491	232,000	106,101	20.89	5,079
1990	138,197.78	86,222	93,261	44,937	21.25	2,115
1991	195,436.44	120,487	130,323	65,114	21.31	3,056
1992	285,466.97	172,765	186,868	98,599	21.69	4,546
1993	87,332.58	51,823	56,053	31,279	22.10	1,415
1994	182,839.56	106,266	114,941	67,899	22.52	3,015
1995	400,287.88	228,845	247,526	152,762	22.66	6,741
1996	825,680.21	461,308	498,966	326,714	23.10	14,143
1997	297,001.05	162,757	176,043	120,958	23.30	5,191
1998	507,766.75	272,569	294,820	212,947	23.51	9,058
1999	147,679.71	77,148	83,446	64,234	24.00	2,676
2000	651,311.57	332,169	359,285	292,027	24.26	12,037
2001	425,833.59	211,682	228,962	196,871	24.53	8,026
2002	262,462.50	126,927	137,288	125,174	24.83	5,041
2003	2,217,243.86	1,040,996	1,125,975	1,091,268	25.14	43,408
2004	1,213,633.44	551,960	597,018	616,615	25.48	24,200
2005	896,588.50	395,754	428,061	468,528	25.62	18,288
2006	871,629.05	370,791	401,060	470,569	26.00	18,099

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2007	742,517.91	304,878	329,766	412,752	26.20	15,754
2008	1,448,013.32	577,757	624,921	823,092	26.36	31,225
2009	550,458.78	209,835	226,964	323,494	26.79	12,075
2010	585,387.03	213,198	230,602	354,785	27.06	13,111
2011	2,489,954.94	866,504	937,239	1,552,716	27.17	57,148
2012	2,440,498.11	803,900	869,525	1,570,974	27.48	57,168
2013	967,365.61	301,044	325,619	641,747	27.66	23,201
2014	1,517,749.53	441,665	477,719	1,040,030	28.02	37,117
2015	5,070,616.34	1,373,630	1,485,763	3,584,853	28.26	126,853
2016	3,462,894.29	868,494	939,392	2,523,503	28.38	88,918
2017	3,151,962.45	720,539	779,359	2,372,604	28.68	82,727
2018	1,750,868.81	361,029	390,501	1,360,368	28.87	47,120
2019	5,094,877.45	933,891	1,010,127	4,084,750	28.96	141,048
2020	3,177,727.34	505,259	546,505	2,631,223	29.10	90,420
2021	7,838,749.92	1,044,121	1,129,356	6,709,394	29.28	229,146
2022	8,148,535.82	867,004	937,780	7,210,756	29.39	245,347
2023	8,111,743.98	634,338	686,121	7,425,623	29.45	252,143
2024	2,928,790.01	142,339	153,959	2,774,831	29.36	94,511
2025	4,333,181.76	72,797	78,740	4,254,442	29.18	145,800
	76,179,326.00	17,859,344	19,316,434	56,862,892		2,014,858
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1929	62.39	62	62			
1930	110.70	110	111			
1932	198.75	195	199			
1952	2,329.83	1,914	1,971	359	8.57	42
1953	1,161.22	944	972	189	8.96	21
1954	1,184.67	954	983	202	9.36	22
1955	9,020.40	7,188	7,403	1,617	9.75	166
1956	489.68	386	398	92	10.15	9
1957	73,352.05	57,230	58,943	14,409	10.55	1,366
1958	56,853.89	43,884	45,198	11,656	10.95	1,064
1959	12,832.66	9,798	10,091	2,741	11.35	241
1960	32,622.98	24,630	25,367	7,256	11.76	617
1961	23,824.55	17,789	18,322	5,503	12.16	453
1962	27,434.39	20,250	20,856	6,578	12.57	523
1963	57,606.75	42,029	43,287	14,319	12.98	1,103

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1964	58,479.46	42,154	43,416	15,063	13.40	1,124
1965	115,288.20	82,119	84,578	30,711	13.81	2,224
1966	93,450.78	65,746	67,714	25,736	14.23	1,809
1967	110,164.83	76,541	78,833	31,332	14.65	2,139
1968	158,485.22	108,727	111,982	46,503	15.07	3,086
1969	420,422.42	284,748	293,273	127,149	15.49	8,208
1970	357,141.46	238,688	245,834	111,307	15.92	6,992
1971	177,034.25	116,733	120,228	56,806	16.35	3,474
1972	61,924.75	40,277	41,483	20,442	16.78	1,218
1973	160,168.83	102,742	105,818	54,351	17.21	3,158
1974	60,341.95	38,154	39,296	21,046	17.65	1,192
1975	28,121.60	17,523	18,048	10,074	18.09	557
1976	50,283.75	30,872	31,796	18,487	18.53	998
1977	213,489.46	129,116	132,982	80,508	18.97	4,244
1978	8,203.40	4,884	5,030	3,173	19.42	163
1979	28,407.30	16,648	17,146	11,261	19.87	567
1980	113,721.31	65,556	67,519	46,203	20.33	2,273
1981	456,117.84	258,655	266,399	189,719	20.78	9,130
1982	329,811.92	231,066	237,984	91,828	18.48	4,969
1983	225,068.98	155,950	160,619	64,450	18.73	3,441
1984	56,272.69	38,299	39,446	16,827	19.36	869
1985	104,584.42	70,302	72,407	32,178	19.63	1,639
1986	133,483.26	88,539	91,190	42,293	19.92	2,123
1987	262,517.66	171,713	176,854	85,664	20.23	4,235
1988	120,169.63	77,437	79,755	40,414	20.55	1,967
1989	200,959.40	127,489	131,306	69,653	20.89	3,334
1990	106,581.06	66,496	68,487	38,094	21.25	1,793
1991	79,951.77	49,290	50,766	29,186	21.31	1,370
1992	148,014.46	89,578	92,260	55,755	21.69	2,571
1993	179,613.22	106,582	109,773	69,840	22.10	3,160
1994	426,429.44	247,841	255,261	171,168	22.52	7,601
1995	293,503.97	167,796	172,820	120,684	22.66	5,326
1996	198,837.25	111,090	114,416	84,421	23.10	3,655
1997	426,703.61	233,834	240,835	185,869	23.30	7,977
1998	449,206.85	241,134	248,353	200,853	23.51	8,543
1999	143,642.05	75,039	77,286	66,356	24.00	2,765
2000	131,131.51	66,877	68,879	62,252	24.26	2,566
2001	716,454.38	356,149	366,812	349,643	24.53	14,254
2002	109,571.13	52,989	54,575	54,996	24.83	2,215
2003	118,221.43	55,505	57,167	61,055	25.14	2,429
2004	494,646.96	224,965	231,700	262,947	25.48	10,320

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2005	286,227.78	126,341	130,124	156,104	25.62	6,093
2006	251,806.96	107,119	110,326	141,481	26.00	5,442
2007	893,846.74	367,013	378,001	515,846	26.20	19,689
2008	793,408.05	316,570	326,048	467,360	26.36	17,730
2009	101,340.29	38,631	39,788	61,553	26.79	2,298
2010	91,265.11	33,239	34,234	57,031	27.06	2,108
2011	1,503,528.26	523,228	538,893	964,635	27.17	35,504
2012	453,390.05	149,347	153,818	299,572	27.48	10,901
2013	22,544.79	7,016	7,226	15,319	27.66	554
2014	3,026,368.23	880,673	907,040	2,119,328	28.02	75,636
2015	1,487,376.42	402,930	414,993	1,072,383	28.26	37,947
2016	1,044,872.38	262,054	269,900	774,973	28.38	27,307
2017	1,887,319.71	431,441	444,358	1,442,962	28.68	50,312
2018	10,750,498.07	2,216,753	2,283,121	8,467,377	28.87	293,293
2019	4,127,665.27	756,601	779,253	3,348,412	28.96	115,622
2020	4,241,025.17	674,323	694,512	3,546,513	29.10	121,873
2021	2,164,451.78	288,305	296,937	1,867,515	29.28	63,781
2022	7,508,181.69	798,871	822,789	6,685,393	29.39	227,472
2023	2,213,333.41	173,083	178,265	2,035,068	29.45	69,102
2024	1,667,743.79	81,052	83,479	1,584,265	29.36	53,960
2025	1,841,806.11	30,942	31,868	1,809,938	29.18	62,027
	54,783,708.83	13,718,738	14,129,462	40,654,247		1,455,956
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1910	59.72	60	60			
1911	77.00	77	77			
1922	246.71	247	247			
1926	227.78	228	228			
1927	201.25	201	201			
1928	1,840.28	1,840	1,840			
1929	56.71	57	57			
1930	20.00	20	20			
1931	25.00	25	25			
1932	105.36	103	105			
1934	274.21	264	274			
1935	279.38	267	279			
1936	449.37	426	449			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1937	1,104.93	1,039	1,105			
1938	461.30	430	461			
1939	446.16	413	446			
1940	101.96	94	102			
1941	248.41	226	248			
1945	106.56	94	105	1	5.86	
1947	493.03	425	475	18	6.63	3
1948	542.60	463	518	25	7.02	4
1949	71.03	60	67	4	7.40	1
1950	51.06	43	48	3	7.79	
1951	43.61	36	40	3	8.18	
1952	325.19	267	299	27	8.57	3
1953	322.15	262	293	29	8.96	3
1954	1,096.04	882	986	110	9.36	12
1955	530.06	422	472	58	9.75	6
1956	7,634.79	6,020	6,730	905	10.15	89
1957	7,465.05	5,824	6,511	954	10.55	90
1958	2,949.29	2,276	2,545	405	10.95	37
1959	1,747.49	1,334	1,491	256	11.35	23
1960	4,346.71	3,282	3,669	677	11.76	58
1961	4,388.76	3,277	3,664	725	12.16	60
1962	3,975.82	2,935	3,281	695	12.57	55
1963	7,791.31	5,684	6,355	1,437	12.98	111
1964	7,770.53	5,601	6,262	1,509	13.40	113
1965	26,322.50	18,749	20,961	5,361	13.81	388
1966	17,123.14	12,047	13,468	3,655	14.23	257
1967	8,251.41	5,733	6,409	1,842	14.65	126
1968	12,121.37	8,316	9,297	2,824	15.07	187
1969	12,319.83	8,344	9,328	2,991	15.49	193
1970	8,708.66	5,820	6,507	2,202	15.92	138
1971	19,997.61	13,186	14,742	5,256	16.35	321
1972	17,355.92	11,289	12,621	4,735	16.78	282
1973	16,876.10	10,825	12,102	4,774	17.21	277
1974	42,435.55	26,832	29,998	12,438	17.65	705
1975	7,785.89	4,852	5,424	2,361	18.09	131
1976	25,005.27	15,352	17,163	7,842	18.53	423
1977	10,014.34	6,057	6,772	3,243	18.97	171
1978	40,405.84	24,058	26,896	13,509	19.42	696
1979	29,172.13	17,096	19,113	10,059	19.87	506
1980	38,163.48	22,000	24,596	13,568	20.33	667
1981	104,206.24	59,093	66,065	38,141	20.78	1,835

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
1982	86,260.92	60,434	67,564	18,697	18.48	1,012
1983	60,843.06	42,158	47,132	13,711	18.73	732
1984	50,463.38	34,345	38,397	12,066	19.36	623
1985	95,865.17	64,441	72,044	23,821	19.63	1,213
1986	85,664.81	56,821	63,525	22,140	19.92	1,111
1987	80,921.17	52,931	59,176	21,745	20.23	1,075
1988	73,193.89	47,166	52,731	20,463	20.55	996
1989	108,490.02	68,826	76,946	31,544	20.89	1,510
1990	76,293.48	47,600	53,216	23,077	21.25	1,086
1991	128,733.69	79,364	88,728	40,006	21.31	1,877
1992	140,158.45	84,824	94,832	45,327	21.69	2,090
1993	102,404.76	60,767	67,936	34,468	22.10	1,560
1994	130,637.67	75,927	84,885	45,753	22.52	2,032
1995	234,053.65	133,808	149,595	84,459	22.66	3,727
1996	174,963.78	97,752	109,285	65,679	23.10	2,843
1997	161,225.41	88,352	98,776	62,449	23.30	2,680
1998	256,965.58	137,939	154,213	102,752	23.51	4,371
1999	132,283.75	69,105	77,258	55,026	24.00	2,293
2000	469,508.63	239,449	267,700	201,809	24.26	8,319
2001	174,540.00	86,764	97,001	77,539	24.53	3,161
2002	364,513.07	176,279	197,077	167,436	24.83	6,743
2003	211,545.74	99,321	111,039	100,507	25.14	3,998
2004	273,572.08	124,421	139,101	134,471	25.48	5,278
2005	434,868.62	191,951	214,598	220,271	25.62	8,598
2006	205,280.32	87,326	97,629	107,651	26.00	4,140
2007	376,599.91	154,632	172,876	203,724	26.20	7,776
2008	403,945.38	161,174	180,190	223,756	26.36	8,488
2009	346,321.64	132,018	147,594	198,728	26.79	7,418
2010	115,623.92	42,110	47,078	68,546	27.06	2,533
2011	721,973.08	251,247	280,890	441,083	27.17	16,234
2012	335,639.58	110,560	123,604	212,035	27.48	7,716
2013	893,607.58	278,091	310,901	582,707	27.66	21,067
2014	1,772,166.07	515,700	576,544	1,195,622	28.02	42,670
2015	2,794,301.60	756,976	846,286	1,948,015	28.26	68,932
2016	907,181.96	227,521	254,365	652,817	28.38	23,003
2017	649,629.67	148,505	166,026	483,604	28.68	16,862
2018	233,259.94	48,098	53,773	179,487	28.87	6,217
2019	408,707.36	74,916	83,755	324,953	28.96	11,221
2020	1,610,640.03	256,092	286,307	1,324,333	29.10	45,510
2021	4,779,150.10	636,583	711,689	4,067,461	29.28	138,916
2022	3,528,845.45	375,469	419,768	3,109,077	29.39	105,787

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. 0						
2023	2,360,822.85	184,616	206,398	2,154,425	29.45	73,155
2024	4,675,667.29	227,237	254,047	4,421,620	29.36	150,600
2025	1,536,300.76	25,810	28,855	1,507,446	29.18	51,660
	33,257,777.16	7,230,279	8,082,829	25,174,948		886,804
	164,220,811.99	38,808,361	41,528,724	122,692,087		4,357,618
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.2	2.65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	1,330.58	1,172	1,236	95	5.37	18
1956	21,290.16	18,499	19,507	1,784	5.90	302
1957	5,372.45	4,635	4,887	485	6.18	78
1958	8,518.07	7,295	7,692	826	6.46	128
1959	4,392.86	3,735	3,938	454	6.74	67
1960	27,087.71	22,856	24,101	2,987	7.03	425
1961	1,916.00	1,604	1,691	225	7.33	31
1962	1,339.47	1,113	1,174	166	7.62	22
1963	30.71	25	26	4	7.93	1
1965	41,595.76	33,683	35,518	6,078	8.56	710
1966	19,579.16	15,716	16,572	3,007	8.88	339
1967	14,375.52	11,433	12,056	2,320	9.21	252
1968	818.29	645	680	138	9.54	14
1969	15,932.36	12,431	13,108	2,824	9.89	286
1970	553.00	427	450	103	10.24	10
1972	36,690.90	27,738	29,249	7,442	10.98	678
1973	38,195.02	28,553	30,108	8,087	11.36	712
1974	19,018.54	14,048	14,813	4,205	11.76	358
1975	25,329.73	18,485	19,492	5,838	12.16	480
1976	12,818.60	9,238	9,741	3,077	12.57	245
1977	148.01	105	111	37	13.00	3
1978	4,242.67	2,976	3,138	1,105	13.44	82
1979	1,542.38	1,066	1,124	418	13.89	30
1980	4,638.03	3,159	3,331	1,307	14.35	91
1981	80,176.22	53,772	56,701	23,476	14.82	1,584
1982	141,945.62	108,049	113,934	28,012	13.57	2,064
1983	6,800.47	5,114	5,393	1,408	13.93	101
1984	199,926.07	147,625	155,665	44,261	14.61	3,030
1985	433,461.53	315,777	332,975	100,486	15.00	6,699
1986	265,735.11	190,878	201,274	64,461	15.39	4,188
1987	791,585.85	560,126	590,633	200,953	15.81	12,710
1988	18,764.80	13,072	13,784	4,981	16.22	307
1989	37,807.02	25,902	27,313	10,494	16.66	630
1990	128,484.87	86,509	91,221	37,264	17.10	2,179
1991	257,739.07	170,366	179,645	78,094	17.56	4,447
1992	198,243.74	128,541	135,542	62,702	18.03	3,478
1993	32,985.36	20,956	22,097	10,888	18.51	588
1994	6,197.62	3,854	4,064	2,134	19.00	112
1995	265,285.40	161,294	170,079	95,207	19.50	4,882
1996	390,043.61	231,608	244,222	145,821	20.01	7,287
1998	8,401.63	4,762	5,021	3,380	20.83	162

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
2003	278,252.13	135,592	142,977	135,275	23.41	5,779
2009	23,277.53	9,027	9,519	13,759	26.05	528
2014	78,923.32	22,872	24,118	54,806	28.18	1,945
2016	168,831.19	41,870	44,150	124,681	28.81	4,328
2017	32,073.62	7,252	7,647	24,427	29.09	840
2019	90,422.23	16,339	17,229	73,193	29.47	2,484
2020	191,930.65	30,095	31,734	160,197	29.59	5,414
2021	1,737,045.60	228,943	241,412	1,495,633	29.63	50,477
2022	16,273,209.43	1,731,469	1,825,772	14,447,438	29.39	491,577
2023	11,855,743.76	942,532	993,866	10,861,878	28.95	375,194
2024	909,861.73	46,221	48,738	861,123	28.00	30,754
2025	14,466,646.64	283,546	298,989	14,167,658	25.07	565,124
	49,676,557.80	5,964,600	6,289,456	43,387,102		1,594,254
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,159	13,575	3,205	7.03	456
1962	29,310.05	24,347	23,343	5,967	7.62	783
1963	28,716.91	23,656	22,680	6,037	7.93	761
1964	1,610.71	1,316	1,262	349	8.24	42
1965	15,073.47	12,206	11,703	3,371	8.56	394
1966	113,790.28	91,336	87,569	26,222	8.88	2,953
1967	4,284.76	3,408	3,267	1,017	9.21	110
1968	122,380.44	96,436	92,458	29,922	9.54	3,136
1969	114,417.87	89,271	85,589	28,829	9.89	2,915
1970	18,752.91	14,485	13,888	4,865	10.24	475
1971	13,464.24	10,290	9,866	3,599	10.61	339
1972	2,349.36	1,776	1,703	647	10.98	59
1974	21,308.55	15,740	15,091	6,218	11.76	529
1975	37,036.13	27,028	25,913	11,123	12.16	915
1977	2,043.72	1,453	1,393	651	13.00	50
1978	2,934.41	2,058	1,973	961	13.44	72
1979	1,353.24	936	897	456	13.89	33
1980	47,010.45	32,019	30,698	16,312	14.35	1,137
1981	687,198.17	460,883	441,874	245,325	14.82	16,554
1982	114,036.20	86,804	83,224	30,812	13.57	2,271
1983	6,538.51	4,917	4,714	1,824	13.93	131
1984	1,848.56	1,365	1,309	540	14.61	37

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1985	33,053.50	24,079	23,086	9,968	15.00	665
1986	796.80	572	548	248	15.39	16
1987	900.93	637	611	290	15.81	18
1988	228,712.92	159,321	152,750	75,963	16.22	4,683
1989	5,767.35	3,951	3,788	1,979	16.66	119
1990	8,208.45	5,527	5,299	2,909	17.10	170
1991	15,153.04	10,016	9,603	5,550	17.56	316
1992	1,292.66	838	803	489	18.03	27
1993	49,169.36	31,237	29,949	19,221	18.51	1,038
1994	82,378.57	51,231	49,118	33,261	19.00	1,751
1995	42,532.19	25,860	24,793	17,739	19.50	910
1996	44,580.63	26,472	25,380	19,200	20.01	960
1997	515,665.73	298,622	286,305	229,361	20.53	11,172
1998	118,063.23	66,918	64,158	53,905	20.83	2,588
1999	58,548.09	32,272	30,941	27,607	21.37	1,292
2000	69,703.96	37,313	35,774	33,930	21.92	1,548
2001	173,986.69	90,717	86,975	87,011	22.26	3,909
2002	184,888.86	93,276	89,429	95,460	22.83	4,181
2003	175,733.00	85,635	82,103	93,630	23.41	4,000
2004	75,956.41	35,836	34,358	41,598	23.79	1,749
2005	48,587.58	22,039	21,130	27,458	24.39	1,126
2006	162,733.73	71,115	68,182	94,552	24.80	3,813
2007	9,461.70	3,972	3,808	5,654	25.23	224
2008	460,995.77	187,164	179,444	281,551	25.60	10,998
2009	53,996.90	20,940	20,076	33,921	26.05	1,302
2010	265,809.52	98,057	94,013	171,797	26.52	6,478
2011	1,348,202.00	471,062	451,633	896,569	27.00	33,206
2012	963,681.06	318,786	305,637	658,044	27.31	24,095
2013	309,369.28	95,904	91,948	217,421	27.82	7,815
2014	7,850,809.11	2,275,164	2,181,323	5,669,486	28.18	201,188
2015	784,772.22	211,732	202,999	581,773	28.41	20,478
2018	1.37			1	29.26	
2019	2,147,672.02	388,084	372,077	1,775,595	29.47	60,251
2020	350,661.95	54,984	52,716	297,946	29.59	10,069
2021	214,987.16	28,335	27,166	187,821	29.63	6,339
2022	5,163,458.24	549,392	526,732	4,636,726	29.39	157,765
2023	4,648,863.73	369,585	354,341	4,294,523	28.95	148,343
2024	667,067.84	33,887	32,489	634,579	28.00	22,664
2025	820,714.65	16,086	15,423	805,292	25.07	32,122
	29,559,177.51	7,312,507	7,010,897	22,548,280		823,540

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1954	266.15	234	169	97	5.37	18
1956	1,419.60	1,233	889	530	5.90	90
1958	1,154.96	989	713	442	6.46	68
1959	352.50	300	216	136	6.74	20
1960	3,229.10	2,725	1,965	1,264	7.03	180
1965	2,958.56	2,396	1,728	1,231	8.56	144
1966	3,788.99	3,041	2,193	1,596	8.88	180
1967	2,785.64	2,216	1,598	1,188	9.21	129
1969	2,147.66	1,676	1,209	939	9.89	95
1971	481.68	368	265	216	10.61	20
1972	1,415.71	1,070	772	644	10.98	59
1973	1,983.52	1,483	1,069	914	11.36	80
1974	1,411.62	1,043	752	659	11.76	56
1976	3,626.30	2,613	1,884	1,742	12.57	139
1978	10,681.17	7,491	5,402	5,279	13.44	393
1980	703.40	479	345	358	14.35	25
1981	2,492.78	1,672	1,206	1,287	14.82	87
1987	1,548.80	1,096	790	758	15.81	48
1988	1,790.48	1,247	899	891	16.22	55
1991	417.27	276	199	218	17.56	12
1994	551.52	343	247	304	19.00	16
2012	1,055.35	349	252	804	27.31	29
2013	422.81	131	94	328	27.82	12
2019	181,294.79	32,760	23,624	157,671	29.47	5,350
2023	653,815.24	51,978	37,483	616,333	28.95	21,290
2024	1,265,047.41	64,264	46,342	1,218,705	28.00	43,525
2025	397,245.69	7,786	5,615	391,631	25.07	15,621
	2,544,088.70	191,259	137,921	2,406,168		87,741
	81,779,824.01	13,468,366	13,438,274	68,341,550		2,505,535

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.3 3.06

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1901	31.86	32	32			
1902	72.19	72	72			
1903	135.03	135	135			
1904	51.59	52	52			
1905	17.64	18	18			
1906	192.85	193	193			
1907	198.52	199	199			
1908	390.45	390	390			
1909	240.92	241	241			
1910	371.33	371	371			
1911	477.41	477	477			
1912	461.94	462	462			
1913	335.48	335	335			
1914	558.70	559	559			
1915	798.52	799	799			
1916	836.03	836	836			
1917	1,030.69	1,031	1,031			
1918	681.77	682	682			
1919	680.60	681	681			
1920	699.32	699	699			
1921	1,153.12	1,153	1,153			
1922	1,900.89	1,901	1,901			
1923	2,455.73	2,456	2,456			
1924	2,216.10	2,216	2,216			
1925	2,730.99	2,731	2,731			
1926	2,367.12	2,367	2,367			
1927	4,900.96	4,901	4,901			
1928	3,110.70	3,111	3,111			
1929	5,369.33	5,369	5,369			
1930	5,343.27	5,343	5,343			
1931	3,008.10	3,008	3,008			
1932	796.52	797	797			
1933	1,809.59	1,810	1,810			
1934	1,577.41	1,577	1,577			
1935	1,470.47	1,470	1,470			
1936	2,753.25	2,753	2,753			
1937	2,456.37	2,456	2,456			
1938	2,150.14	2,150	2,150			
1939	2,523.60	2,524	2,524			
1940	2,577.25	2,577	2,577			
1941	3,889.96	3,890	3,890			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1942	1,716.00	1,707	1,586	130	0.23	130
1943	1,133.00	1,124	1,044	89	0.34	89
1944	1,828.70	1,805	1,677	152	0.59	152
1945	950.37	932	866	84	0.85	84
1946	2,634.44	2,569	2,387	247	1.12	221
1947	9,329.37	9,043	8,403	927	1.38	672
1948	7,533.65	7,257	6,743	791	1.65	479
1949	14,058.10	13,458	12,505	1,553	1.92	809
1950	14,965.20	14,234	13,226	1,739	2.20	790
1951	10,718.25	10,128	9,411	1,307	2.48	527
1952	11,528.72	10,819	10,053	1,476	2.77	533
1953	11,319.50	10,552	9,805	1,515	3.05	497
1954	16,453.84	15,233	14,154	2,300	3.34	689
1955	37,964.65	34,902	32,430	5,534	3.63	1,525
1956	69,288.23	63,253	58,774	10,514	3.92	2,682
1957	83,793.08	75,953	70,575	13,219	4.21	3,140
1958	114,201.24	102,781	95,503	18,698	4.50	4,155
1959	202,817.88	181,230	168,397	34,421	4.79	7,186
1960	280,512.76	248,784	231,167	49,346	5.09	9,695
1961	303,863.16	267,533	248,588	55,275	5.38	10,274
1962	284,792.62	248,909	231,283	53,510	5.67	9,437
1963	325,282.82	282,128	262,150	63,133	5.97	10,575
1964	312,557.89	268,937	249,893	62,665	6.28	9,979
1965	387,717.18	330,940	307,505	80,212	6.59	12,172
1966	546,888.10	463,034	430,245	116,643	6.90	16,905
1967	502,254.87	421,673	391,813	110,442	7.22	15,297
1968	588,000.03	489,345	454,693	133,307	7.55	17,657
1969	618,454.37	510,021	473,905	144,550	7.89	18,321
1970	611,665.44	499,663	464,280	147,385	8.24	17,887
1971	681,667.07	551,544	512,487	169,180	8.59	19,695
1972	951,604.26	762,130	708,161	243,443	8.96	27,170
1973	1,174,381.82	930,627	864,726	309,656	9.34	33,154
1974	1,220,345.17	956,482	888,750	331,595	9.73	34,080
1975	794,855.64	615,926	572,310	222,545	10.13	21,969
1976	876,909.07	671,327	623,788	253,121	10.55	23,993
1977	1,685,824.08	1,274,854	1,184,577	501,247	10.97	45,693
1978	1,556,834.41	1,162,083	1,079,792	477,042	11.41	41,809
1979	2,861,428.84	2,107,271	1,958,048	903,381	11.86	76,170
1980	4,807,997.86	3,490,606	3,243,425	1,564,573	12.33	126,892
1981	4,859,440.98	3,476,104	3,229,950	1,629,491	12.81	127,205
1982	4,270,234.10	3,342,739	3,106,029	1,164,205	12.00	97,017

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1983	3,151,174.46	2,436,488	2,263,952	887,222	12.39	71,608
1984	3,327,898.51	2,539,519	2,359,687	968,211	12.81	75,582
1985	3,815,277.65	2,871,759	2,668,400	1,146,877	13.22	86,753
1986	4,108,532.05	3,031,686	2,817,002	1,291,530	13.94	92,649
1987	4,858,890.61	3,531,442	3,281,369	1,577,522	14.38	109,703
1988	6,240,056.34	4,462,888	4,146,856	2,093,200	14.83	141,146
1989	8,859,870.41	6,230,261	5,789,076	3,070,795	15.30	200,706
1990	9,823,430.81	6,787,008	6,306,398	3,517,033	15.77	223,020
1991	8,890,435.10	6,029,493	5,602,525	3,287,910	16.25	202,333
1992	8,855,179.12	5,888,694	5,471,696	3,383,483	16.75	201,999
1993	6,050,619.96	3,941,374	3,662,272	2,388,348	17.26	138,375
1994	11,915,673.18	7,596,242	7,058,327	4,857,346	17.77	273,345
1995	12,650,716.65	7,883,927	7,325,640	5,325,076	18.29	291,147
1996	10,498,424.13	6,387,241	5,934,940	4,563,485	18.83	242,352
1997	11,731,486.18	6,959,118	6,466,320	5,265,166	19.37	271,821
1998	9,376,013.00	5,416,523	5,032,961	4,343,052	19.92	218,025
1999	9,530,802.58	5,354,405	4,975,242	4,555,560	20.48	222,439
2000	10,000,417.60	5,479,229	5,091,227	4,909,191	20.83	235,679
2001	9,860,616.91	5,236,974	4,866,127	4,994,490	21.41	233,278
2002	10,362,258.96	5,324,129	4,947,110	5,415,149	22.00	246,143
2003	8,160,247.85	4,049,115	3,762,384	4,397,864	22.59	194,682
2004	11,182,595.36	5,346,399	4,967,803	6,214,792	23.20	267,879
2005	9,389,280.55	4,335,031	4,028,053	5,361,227	23.61	227,074
2006	10,207,440.40	4,519,855	4,199,789	6,007,651	24.23	247,943
2007	10,144,560.67	4,295,207	3,991,049	6,153,511	24.85	247,626
2008	13,308,097.84	5,449,666	5,063,757	8,244,340	25.24	326,638
2009	13,550,394.03	5,276,523	4,902,875	8,647,519	25.87	334,268
2010	14,002,116.39	5,186,384	4,819,119	9,182,997	26.34	348,633
2011	21,470,072.80	7,501,643	6,970,427	14,499,646	27.00	537,024
2012	31,578,691.19	10,402,021	9,665,420	21,913,271	27.48	797,426
2013	40,916,952.62	12,635,155	11,740,418	29,176,534	27.98	1,042,764
2014	39,796,783.60	11,441,575	10,631,360	29,165,424	28.50	1,023,348
2015	41,552,718.24	11,036,402	10,254,878	31,297,840	29.03	1,078,121
2016	45,293,581.06	11,015,399	10,235,363	35,058,218	29.56	1,186,002
2017	42,941,063.64	9,489,975	8,817,959	34,123,105	29.96	1,138,955
2018	49,012,958.42	9,665,355	8,980,920	40,032,039	30.52	1,311,666
2019	64,974,483.69	11,279,570	10,480,827	54,493,657	30.95	1,760,700
2020	56,799,065.66	8,497,140	7,895,430	48,903,636	31.26	1,564,416
2021	74,833,113.88	9,324,206	8,663,929	66,169,185	31.60	2,093,962
2022	94,871,890.46	9,392,317	8,727,216	86,144,674	31.84	2,705,549

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2023	98,971,938.33	7,224,951	6,713,329	92,258,610	31.75	2,905,783
2024	66,132,616.09	3,015,647	2,802,099	63,330,517	31.39	2,017,538
2025	54,845,598.36	910,437	845,966	53,999,632	29.62	1,823,080
	1,109,024,605.81	298,672,837	277,527,428	831,497,177		29,806,586
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1912	316.08	316	316			
1917	4,216.37	4,216	4,216			
1918	859.13	859	859			
1919	3,477.63	3,478	3,478			
1920	4,143.36	4,143	4,143			
1921	3,807.14	3,807	3,807			
1922	10,244.87	10,245	10,245			
1923	12,177.47	12,177	12,177			
1924	20,910.20	20,910	20,910			
1925	24,765.80	24,766	24,766			
1926	18,434.03	18,434	18,434			
1927	16,054.69	16,055	16,055			
1928	14,479.95	14,480	14,480			
1929	13,535.42	13,535	13,535			
1930	13,568.21	13,568	13,568			
1931	13,326.51	13,327	13,327			
1932	10,830.93	10,831	10,831			
1933	6,726.58	6,727	6,727			
1934	8,773.01	8,773	8,773			
1935	6,694.55	6,695	6,695			
1936	9,338.60	9,339	9,339			
1937	10,025.01	10,025	10,025			
1938	7,784.82	7,785	7,785			
1939	12,403.70	12,404	12,404			
1940	11,117.77	11,118	11,118			
1941	10,030.38	10,030	10,030			
1942	6,049.91	6,019	5,928	122	0.23	122
1943	4,274.07	4,242	4,178	96	0.34	96
1944	6,869.42	6,779	6,676	193	0.59	193
1945	11,193.49	10,982	10,815	378	0.85	378
1946	18,818.93	18,351	18,073	746	1.12	666

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1947	20,023.31	19,409	19,115	909	1.38	659
1948	24,183.32	23,297	22,944	1,240	1.65	752
1949	21,570.50	20,650	20,337	1,234	1.92	643
1950	30,589.50	29,094	28,653	1,937	2.20	880
1951	23,066.28	21,795	21,464	1,602	2.48	646
1952	1,731,328.71	1,624,748	1,600,109	131,220	2.77	47,372
1953	18,005.15	16,785	16,530	1,475	3.05	484
1954	25,531.37	23,636	23,278	2,254	3.34	675
1955	43,141.87	39,662	39,061	4,081	3.63	1,124
1956	49,594.47	45,274	44,587	5,007	3.92	1,277
1957	68,796.57	62,360	61,414	7,382	4.21	1,753
1958	100,877.91	90,790	89,413	11,465	4.50	2,548
1959	159,899.94	142,880	140,713	19,187	4.79	4,006
1960	140,028.78	124,190	122,307	17,722	5.09	3,482
1961	168,314.34	148,191	145,944	22,371	5.38	4,158
1962	305,305.69	266,837	262,790	42,515	5.67	7,498
1963	383,789.12	332,872	327,824	55,965	5.97	9,374
1964	517,318.40	445,121	438,371	78,948	6.28	12,571
1965	615,467.52	525,338	517,371	98,096	6.59	14,886
1966	679,637.53	575,429	566,703	112,935	6.90	16,367
1967	794,823.67	667,302	657,183	137,641	7.22	19,064
1968	1,027,607.07	855,195	842,226	185,381	7.55	24,554
1969	1,083,589.99	893,604	880,053	203,537	7.89	25,797
1970	1,241,284.05	1,013,993	998,616	242,668	8.24	29,450
1971	418,613.45	338,704	333,568	85,046	8.59	9,901
1972	703,924.33	563,766	555,217	148,708	8.96	16,597
1973	1,315,111.11	1,042,147	1,026,343	288,768	9.34	30,917
1974	1,350,366.50	1,058,390	1,042,340	308,027	9.73	31,657
1975	1,151,836.17	892,546	879,011	272,825	10.13	26,932
1976	1,393,091.79	1,066,495	1,050,322	342,770	10.55	32,490
1977	1,772,387.37	1,340,315	1,319,989	452,398	10.97	41,240
1978	1,347,230.42	1,005,627	990,377	356,854	11.41	31,276
1979	1,698,077.73	1,250,532	1,231,568	466,510	11.86	39,335
1980	1,925,293.74	1,397,763	1,376,566	548,728	12.33	44,503
1981	1,763,146.82	1,261,232	1,242,106	521,041	12.81	40,675
1982	1,443,638.01	1,130,080	1,112,943	330,695	12.00	27,558
1983	1,107,044.43	855,967	842,986	264,058	12.39	21,312
1984	1,572,672.77	1,200,107	1,181,908	390,765	12.81	30,505
1985	2,011,905.13	1,514,361	1,491,396	520,509	13.22	39,373
1986	2,519,948.43	1,859,470	1,831,272	688,677	13.94	49,403
1987	3,338,790.66	2,426,633	2,389,834	948,957	14.38	65,991

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1988	4,438,565.73	3,174,462	3,126,322	1,312,244	14.83	88,486
1989	4,204,630.23	2,956,696	2,911,858	1,292,772	15.30	84,495
1990	4,622,072.52	3,193,390	3,144,963	1,477,110	15.77	93,666
1991	3,388,060.47	2,297,783	2,262,938	1,125,123	16.25	69,238
1992	4,191,150.20	2,787,115	2,744,849	1,446,301	16.75	86,346
1993	4,433,083.49	2,887,711	2,843,919	1,589,164	17.26	92,072
1994	4,514,330.79	2,877,886	2,834,243	1,680,087	17.77	94,546
1995	5,184,956.98	3,231,265	3,182,264	2,002,693	18.29	109,497
1996	5,060,243.89	3,078,652	3,031,965	2,028,279	18.83	107,715
1997	6,132,858.49	3,638,012	3,582,842	2,550,016	19.37	131,648
1998	5,567,920.47	3,216,588	3,167,809	2,400,111	19.92	120,488
1999	4,033,494.97	2,266,017	2,231,653	1,801,842	20.48	87,981
2000	3,230,828.86	1,770,171	1,743,327	1,487,502	20.83	71,412
2001	5,921,692.41	3,145,011	3,097,318	2,824,375	21.41	131,918
2002	4,945,913.35	2,541,210	2,502,673	2,443,240	22.00	111,056
2003	5,310,703.27	2,635,171	2,595,209	2,715,494	22.59	120,208
2004	11,395,425.16	5,448,153	5,365,533	6,029,892	23.20	259,909
2005	7,379,236.51	3,406,993	3,355,327	4,023,910	23.61	170,432
2006	4,327,188.73	1,916,079	1,887,022	2,440,167	24.23	100,709
2007	5,943,536.18	2,516,493	2,478,331	3,465,205	24.85	139,445
2008	6,371,077.39	2,608,956	2,569,392	3,801,686	25.24	150,621
2009	6,369,356.75	2,480,228	2,442,616	3,926,741	25.87	151,787
2010	4,229,479.73	1,566,599	1,542,842	2,686,638	26.34	101,998
2011	7,335,484.57	2,563,018	2,524,150	4,811,334	27.00	178,198
2012	9,231,103.20	3,040,725	2,994,613	6,236,490	27.48	226,947
2013	9,123,380.77	2,817,300	2,774,576	6,348,805	27.98	226,905
2014	9,675,205.84	2,781,622	2,739,439	6,935,767	28.50	243,360
2015	14,042,601.81	3,729,715	3,673,155	10,369,447	29.03	357,198
2016	15,588,014.78	3,791,005	3,733,515	11,854,500	29.56	401,032
2017	17,129,013.06	3,785,512	3,728,105	13,400,908	29.96	447,293
2018	19,390,522.37	3,823,811	3,765,824	15,624,699	30.52	511,950
2019	23,540,142.87	4,086,569	4,024,597	19,515,546	30.95	630,551
2020	18,169,135.80	2,718,103	2,676,884	15,492,252	31.26	495,593
2021	32,240,949.33	4,017,222	3,956,302	28,284,648	31.60	895,084
2022	29,078,461.42	2,878,768	2,835,112	26,243,349	31.84	824,226
2023	25,345,527.31	1,850,223	1,822,165	23,523,363	31.75	740,893
2024	16,407,054.15	748,162	736,816	15,670,238	31.39	499,211
2025	19,198,917.00	318,702	313,869	18,885,048	29.62	637,578
	423,113,422.80	137,118,101	135,042,798	288,070,625		10,802,832

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1929	393.08	393	393			
1930	412.70	413	413			
1934	20.28	20	20			
1940	55.25	55	55			
1941	35.71	36	36			
1945	295.40	290	286	10	0.85	10
1946	129.32	126	124	5	1.12	4
1947	4.26	4	4			
1948	225.53	217	214	12	1.65	7
1950	66.68	63	62	5	2.20	2
1951	45.62	43	42	3	2.48	1
1952	75.13	71	70	5	2.77	2
1953	455.66	425	419	37	3.05	12
1954	1,300.00	1,204	1,187	113	3.34	34
1955	926.71	852	840	87	3.63	24
1957	3,176.75	2,880	2,839	338	4.21	80
1958	1,183.16	1,065	1,050	133	4.50	30
1959	208.57	186	183	25	4.79	5
1960	21,168.19	18,774	18,505	2,663	5.09	523
1961	7,856.86	6,917	6,818	1,039	5.38	193
1962	17,208.34	15,040	14,825	2,384	5.67	420
1963	18,776.69	16,286	16,053	2,724	5.97	456
1964	15,829.89	13,621	13,426	2,404	6.28	383
1965	13,781.27	11,763	11,595	2,187	6.59	332
1966	28,195.75	23,872	23,530	4,665	6.90	676
1967	32,358.58	27,167	26,778	5,580	7.22	773
1968	28,452.87	23,679	23,340	5,113	7.55	677
1969	31,350.23	25,854	25,484	5,866	7.89	743
1970	50,291.04	41,082	40,494	9,797	8.24	1,189
1971	74,021.56	59,892	59,035	14,987	8.59	1,745
1972	43,241.02	34,631	34,135	9,106	8.96	1,016
1973	91,526.88	72,530	71,492	20,035	9.34	2,145
1974	136,645.99	107,100	105,567	31,079	9.73	3,194
1975	96,980.27	75,149	74,074	22,907	10.13	2,261
1976	49,459.99	37,865	37,323	12,137	10.55	1,150
1977	65,537.14	49,560	48,851	16,686	10.97	1,521
1978	59,148.61	44,151	43,519	15,629	11.41	1,370
1979	145,144.35	106,890	105,360	39,784	11.86	3,354
1980	339,140.31	246,216	242,693	96,448	12.33	7,822
1981	331,539.03	237,160	233,766	97,773	12.81	7,633
1982	278,665.57	218,139	215,018	63,648	12.00	5,304

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1983	399,124.38	308,603	304,187	94,937	12.39	7,662
1984	512,283.88	390,924	385,330	126,954	12.81	9,911
1985	580,334.94	436,818	430,567	149,768	13.22	11,329
1986	748,903.47	552,616	544,708	204,195	13.94	14,648
1987	720,678.45	523,789	516,294	204,385	14.38	14,213
1988	1,202,624.51	860,117	847,809	354,815	14.83	23,925
1989	1,268,651.98	892,116	879,350	389,302	15.30	25,445
1990	1,108,641.00	765,960	754,999	353,642	15.77	22,425
1991	1,706,381.35	1,157,268	1,140,708	565,673	16.25	34,811
1992	1,244,947.91	827,890	816,043	428,905	16.75	25,606
1993	2,197,512.30	1,431,460	1,410,976	786,536	17.26	45,570
1994	2,513,607.85	1,602,425	1,579,495	934,113	17.77	52,567
1995	2,415,803.60	1,505,529	1,483,985	931,818	18.29	50,947
1996	2,459,155.61	1,496,150	1,474,741	984,415	18.83	52,279
1997	2,784,901.64	1,652,004	1,628,364	1,156,537	19.37	59,708
1998	2,474,376.24	1,429,447	1,408,992	1,065,384	19.92	53,483
1999	2,183,978.93	1,226,959	1,209,402	974,577	20.48	47,587
2000	2,266,171.35	1,241,635	1,223,868	1,042,304	20.83	50,039
2001	1,832,142.67	973,051	959,127	873,016	21.41	40,776
2002	2,328,262.04	1,196,261	1,179,143	1,149,119	22.00	52,233
2003	2,670,887.96	1,325,295	1,306,331	1,364,557	22.59	60,405
2004	2,231,553.64	1,066,906	1,051,639	1,179,915	23.20	50,858
2005	2,332,760.29	1,077,035	1,061,623	1,271,137	23.61	53,839
2006	2,289,114.27	1,013,620	999,116	1,289,999	24.23	53,240
2007	2,501,935.40	1,059,319	1,044,161	1,457,775	24.85	58,663
2008	3,645,330.98	1,492,763	1,471,402	2,173,929	25.24	86,130
2009	3,068,037.01	1,194,694	1,177,598	1,890,439	25.87	73,075
2010	3,334,054.32	1,234,934	1,217,263	2,116,792	26.34	80,364
2011	5,940,547.48	2,075,627	2,045,926	3,894,622	27.00	144,245
2012	5,371,797.31	1,769,470	1,744,150	3,627,648	27.48	132,010
2013	6,994,260.87	2,159,828	2,128,922	4,865,339	27.98	173,886
2014	6,801,704.01	1,955,490	1,927,508	4,874,196	28.50	171,024
2015	6,454,125.95	1,714,216	1,689,686	4,764,440	29.03	164,121
2016	4,833,092.94	1,175,408	1,158,588	3,674,505	29.56	124,307
2017	5,158,189.00	1,139,960	1,123,648	4,034,541	29.96	134,664
2018	1,323,058.32	260,907	257,174	1,065,885	30.52	34,924
2019	5,740,114.57	996,484	982,225	4,757,890	30.95	153,728
2020	4,758,612.39	711,888	701,701	4,056,911	31.26	129,780
2021	8,696,119.03	1,083,536	1,068,031	7,628,088	31.60	241,395
2022	6,438,972.99	637,458	628,336	5,810,637	31.84	182,495

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2023	6,613,803.29	482,808	475,899	6,137,904	31.75	193,320
2024	13,487,157.51	615,014	606,213	12,880,944	31.39	410,352
2025	6,723,662.12	111,613	110,016	6,613,646	29.62	223,283
	152,342,705.99	48,346,976	47,655,163	104,687,543		3,870,363
	1,684,480,734.60	484,137,914	460,225,389	1,224,255,345		44,479,781
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.5	2.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1929	54.93	55	55			
1930	68.92	69	69			
1931	135.58	136	136			
1932	144.99	145	145			
1933	39.72	40	40			
1934	261.78	262	262			
1935	618.93	619	619			
1936	1,035.81	1,036	1,036			
1937	1,823.58	1,824	1,824			
1938	1,847.19	1,847	1,847			
1939	2,407.63	2,408	2,408			
1940	2,769.15	2,769	2,769			
1941	3,972.53	3,973	3,973			
1942	1,538.43	1,538	1,538			
1943	453.32	453	453			
1944	1,187.04	1,187	1,187			
1945	1,401.16	1,401	1,401			
1946	2,671.69	2,672	2,672			
1947	2,949.57	2,950	2,950			
1948	2,240.76	2,241	2,241			
1949	4,716.53	4,717	4,717			
1950	4,328.97	4,329	4,329			
1951	5,119.55	5,120	5,120			
1952	7,227.53	7,228	7,228			
1953	5,643.52	5,644	5,644			
1954	2,064.71	2,065	2,065			
1955	3,721.22	3,721	3,721			
1956	4,101.54	4,102	4,102			
1957	3,284.12	3,284	3,284			
1958	4,845.09	4,845	4,845			
1959	4,888.83	4,863	4,889			
1960	5,755.01	5,688	5,755			
1961	7,242.33	7,108	7,242			
1962	8,728.09	8,503	8,728			
1963	8,961.79	8,663	8,962			
1964	10,735.77	10,297	10,736			
1965	10,194.55	9,699	10,195			
1966	9,922.71	9,363	9,923			
1967	25,856.68	24,197	25,857			
1968	57,230.94	53,098	57,231			
1969	55,594.39	51,131	55,594			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1970	48,552.65	44,264	48,553			
1971	20,784.63	18,781	20,785			
1972	20,162.18	18,056	20,162			
1973	40,590.67	36,024	40,536	54	4.05	13
1974	44,803.80	39,390	44,324	480	4.35	110
1975	37,239.10	32,439	36,502	737	4.64	159
1976	25,050.02	21,606	24,312	738	4.95	149
1977	33,195.05	28,354	31,906	1,289	5.25	246
1978	82,642.34	69,856	78,606	4,036	5.57	725
1979	100,569.81	84,116	94,652	5,918	5.89	1,005
1980	425,619.49	351,962	396,049	29,571	6.23	4,747
1981	248,368.43	203,041	228,474	19,895	6.57	3,028
1982	153,231.64	133,204	149,889	3,343	6.50	514
1983	17,034.57	14,682	16,521	514	6.77	76
1984	86,684.41	74,020	83,292	3,393	7.06	481
1985	301,208.91	254,582	286,471	14,738	7.37	2,000
1986	192,231.72	159,956	179,992	12,240	7.92	1,545
1987	301,684.58	248,105	279,182	22,502	8.26	2,724
1988	282,056.47	229,030	257,718	24,338	8.62	2,823
1989	367,994.48	294,800	331,726	36,268	9.00	4,030
1990	720,749.46	569,104	640,390	80,360	9.39	8,558
1991	774,395.09	602,092	677,510	96,885	9.80	9,886
1992	743,869.79	568,912	640,174	103,696	10.23	10,136
1993	621,759.88	467,190	525,710	96,050	10.67	9,002
1994	862,793.62	636,310	716,014	146,780	11.12	13,200
1995	1,071,678.74	774,824	871,878	199,801	11.59	17,239
1996	761,905.61	539,277	606,826	155,079	12.07	12,848
1997	980,451.53	678,571	763,568	216,883	12.57	17,254
1998	897,676.23	606,650	682,639	215,038	13.07	16,453
1999	1,166,438.55	768,566	864,836	301,603	13.59	22,193
2000	1,223,499.58	784,753	883,051	340,449	14.12	24,111
2001	1,608,129.51	1,006,046	1,132,063	476,067	14.51	32,810
2002	1,350,103.03	819,243	921,861	428,242	15.07	28,417
2003	1,082,817.26	636,047	715,718	367,099	15.63	23,487
2004	1,020,555.55	579,063	651,596	368,960	16.20	22,775
2005	1,143,770.43	627,701	706,326	437,444	16.65	26,273
2006	6,319,800.69	3,333,063	3,750,560	2,569,241	17.25	148,942
2007	722,561.60	365,255	411,007	311,555	17.85	17,454
2008	2,624,223.56	1,285,870	1,446,937	1,177,286	18.21	64,651
2009	1,078,831.55	503,814	566,921	511,910	18.83	27,186
2010	812,685.18	361,482	406,761	405,924	19.34	20,989

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
2011	1,586,020.71	669,301	753,137	832,884	19.86	41,938
2012	1,307,599.21	518,986	583,994	723,605	20.51	35,281
2013	2,116,427.49	788,369	887,120	1,229,308	21.06	58,372
2014	2,721,449.77	945,160	1,063,550	1,657,900	21.61	76,719
2015	1,823,437.84	585,871	659,257	1,164,181	22.18	52,488
2016	2,661,836.01	786,306	884,798	1,777,038	22.66	78,422
2017	3,000,921.21	806,047	907,012	2,093,909	23.15	90,450
2018	6,513,499.43	1,568,451	1,764,914	4,748,585	23.65	200,786
2019	2,182,007.19	462,367	520,283	1,661,724	24.17	68,752
2020	2,344,702.48	428,143	481,772	1,862,931	24.62	75,667
2021	2,638,684.59	402,663	453,100	2,185,584	25.00	87,423
2022	5,361,280.40	650,859	732,385	4,628,895	25.32	182,816
2023	3,764,873.09	336,956	379,163	3,385,710	25.43	133,138
2024	4,647,227.51	260,245	292,843	4,354,384	25.31	172,042
2025	6,612,783.47	134,901	151,799	6,460,985	23.95	269,770
	79,978,938.37	28,480,016	32,024,909	47,954,030		2,222,303
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1955	1,580.33	1,580	1,580			
1956	4,300.53	4,301	4,301			
1957	1,540.55	1,541	1,541			
1958	6,960.79	6,961	6,961			
1959	3,293.84	3,276	3,294			
1960	9,934.81	9,819	9,935			
1961	30,774.25	30,202	30,774			
1962	53,446.21	52,066	53,446			
1963	61,997.05	59,931	61,997			
1964	135,933.60	130,383	135,934			
1965	249,744.91	237,605	249,745			
1966	366,936.66	346,245	366,937			
1967	287,501.54	269,053	287,502			
1968	336,891.85	312,562	336,892			
1969	504,487.83	463,988	504,488			
1970	430,853.59	392,796	430,854			
1971	278,816.49	251,941	278,816			
1972	275,265.69	246,517	275,266			
1973	121,606.65	107,926	121,607			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1974	37,635.38	33,088	37,635			
1975	61,849.99	53,878	61,349	501	4.64	108
1976	26,707.52	23,035	26,229	478	4.95	97
1977	44,209.87	37,763	42,999	1,210	5.25	230
1978	38,890.94	32,874	37,433	1,458	5.57	262
1979	119,508.80	99,956	113,817	5,692	5.89	966
1980	904,600.55	748,050	851,779	52,821	6.23	8,478
1981	1,294,047.99	1,057,884	1,204,577	89,471	6.57	13,618
1982	83,479.05	72,568	82,631	848	6.50	130
1983	49,156.18	42,368	48,243	913	6.77	135
1984	246,629.04	210,597	239,800	6,829	7.06	967
1985	486,526.28	411,212	468,233	18,293	7.37	2,482
1986	593,793.28	494,095	562,609	31,184	7.92	3,937
1987	529,897.58	435,788	496,217	33,681	8.26	4,078
1988	646,599.81	525,039	597,844	48,756	8.62	5,656
1989	606,522.44	485,885	553,261	53,262	9.00	5,918
1990	605,801.28	478,341	544,671	61,131	9.39	6,510
1991	715,652.75	556,420	633,577	82,076	9.80	8,375
1992	1,088,478.20	832,468	947,903	140,575	10.23	13,741
1993	1,290,370.30	969,584	1,104,032	186,338	10.67	17,464
1994	2,316,786.26	1,708,630	1,945,559	371,227	11.12	33,384
1995	377,540.62	272,962	310,813	66,728	11.59	5,757
1996	1,159,891.15	820,971	934,812	225,079	12.07	18,648
1997	1,086,479.34	751,952	856,222	230,257	12.57	18,318
1998	1,502,029.80	1,015,072	1,155,828	346,202	13.07	26,488
1999	749,011.47	493,524	561,959	187,052	13.59	13,764
2000	802,171.59	514,513	585,858	216,313	14.12	15,320
2001	943,108.07	590,008	671,822	271,286	14.51	18,696
2002	961,435.81	583,399	664,297	297,139	15.07	19,717
2003	588,753.77	345,834	393,789	194,964	15.63	12,474
2004	1,792,950.01	1,017,320	1,158,388	634,562	16.20	39,170
2005	1,230,423.70	675,257	768,892	461,531	16.65	27,720
2006	1,280,976.35	675,587	769,268	511,708	17.25	29,664
2007	960,657.73	485,612	552,950	407,708	17.85	22,841
2008	519,264.56	254,440	289,722	229,542	18.21	12,605
2009	739,859.39	345,514	393,425	346,434	18.83	18,398
2010	389,053.63	173,051	197,047	192,006	19.34	9,928
2011	1,189,954.49	502,161	571,794	618,161	19.86	31,126
2012	521,444.49	206,961	235,659	285,785	20.51	13,934
2013	659,649.16	245,719	279,792	379,857	21.06	18,037
2014	1,009,264.64	350,518	399,123	610,142	21.61	28,234

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
2015	1,067,261.53	342,911	390,461	676,800	22.18	30,514
2016	947,810.78	279,983	318,807	629,004	22.66	27,758
2017	918,036.62	246,585	280,778	637,259	23.15	27,527
2018	3,360,974.95	809,323	921,549	2,439,426	23.65	103,147
2019	675,769.87	143,196	163,052	512,717	24.17	21,213
2020	1,807,301.53	330,013	375,775	1,431,527	24.62	58,145
2021	1,190,949.39	181,739	206,940	984,009	25.00	39,360
2022	3,558,926.48	432,054	491,965	3,066,961	25.32	121,128
2023	2,710,972.60	242,632	276,277	2,434,696	25.43	95,741
2024	2,558,100.86	143,254	163,118	2,394,982	25.31	94,626
2025	5,207,716.98	106,237	120,968	5,086,749	23.95	212,390
	57,416,752.02	25,816,518	29,223,416	28,193,336		1,358,924
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1966	16,556.84	15,623	13,643	2,913	2.03	1,435
1967	23,712.61	22,191	19,379	4,333	2.31	1,876
1968	41,343.79	38,358	33,498	7,846	2.60	3,018
1969	27,869.04	25,632	22,384	5,485	2.89	1,898
1970	26,296.73	23,974	20,936	5,361	3.18	1,686
1971	65,302.00	59,008	51,531	13,771	3.47	3,969
1972	90,224.32	80,801	70,562	19,662	3.76	5,229
1973	48,674.77	43,199	37,725	10,950	4.05	2,704
1974	51,686.57	45,441	39,683	12,004	4.35	2,760
1975	33,514.45	29,195	25,496	8,019	4.64	1,728
1976	13,638.29	11,763	10,272	3,366	4.95	680
1977	8,024.64	6,854	5,986	2,039	5.25	388
1978	20,233.89	17,103	14,936	5,298	5.57	951
1979	82,217.01	68,765	60,052	22,165	5.89	3,763
1980	35,257.75	29,156	25,462	9,796	6.23	1,572
1981	74,655.56	61,031	53,298	21,358	6.57	3,251
1982	65,297.22	56,763	49,570	15,727	6.50	2,420
1983	51,113.58	44,055	38,473	12,641	6.77	1,867
1984	67,115.22	57,310	50,048	17,067	7.06	2,417
1985	88,458.81	74,765	65,291	23,167	7.37	3,143
1986	61,903.59	51,510	44,983	16,921	7.92	2,136
1987	10,880.03	8,948	7,814	3,066	8.26	371
1988	24,115.88	19,582	17,101	7,015	8.62	814

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 36-R2						
NET SALVAGE PERCENT.. 0						
1989	152,844.75	122,444	106,929	45,916	9.00	5,102
1990	178,467.28	140,918	123,062	55,405	9.39	5,900
1991	153,366.57	119,243	104,133	49,233	9.80	5,024
1992	73,625.00	56,308	49,173	24,452	10.23	2,390
1993	63,391.72	47,633	41,597	21,794	10.67	2,043
1995	23,870.99	17,259	15,072	8,799	11.59	759
1996	16,217.76	11,479	10,024	6,193	12.07	513
2000	4,157.02	2,666	2,328	1,829	14.12	130
2001	3,650.45	2,284	1,995	1,656	14.51	114
2002	14,474.51	8,783	7,670	6,804	15.07	451
2003	101,296.17	59,501	51,961	49,335	15.63	3,156
2004	44,912.16	25,483	22,254	22,658	16.20	1,399
2006	128,924.74	67,995	59,379	69,546	17.25	4,032
2008	82,533.52	40,441	35,317	47,217	18.21	2,593
2011	31,395.48	13,249	11,570	19,825	19.86	998
2012	741,450.15	294,282	256,993	484,457	20.51	23,621
2013	1,254,670.45	467,365	408,144	846,526	21.06	40,196
2014	612,660.37	212,777	185,815	426,845	21.61	19,752
2015	881,785.59	283,318	247,418	634,368	22.18	28,601
2016	425,095.44	125,573	109,661	315,434	22.66	13,920
2017	803,126.17	215,720	188,386	614,741	23.15	26,555
2018	973,306.51	234,372	204,674	768,632	23.65	32,500
2019	876,093.76	185,644	162,121	713,973	24.17	29,540
2020	835,716.50	152,602	133,265	702,451	24.62	28,532
2021	961,735.97	146,761	128,165	833,571	25.00	33,343
2022	1,206,631.42	146,485	127,924	1,078,708	25.32	42,603
2023	1,449,796.15	129,757	113,315	1,336,481	25.43	52,555
2024	900,867.78	50,449	44,056	856,811	25.31	33,853
2025	779,913.33	15,910	13,894	766,019	23.95	31,984
	14,804,070.30	4,287,728	3,744,419	11,059,651		522,235
	152,199,760.69	58,584,262	64,992,744	87,207,017		4,103,462

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.3 2.70

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	2,621,381.98	2,124,892	1,183,584	1,437,798	3.62	397,182
2012	2,608,923.22	1,958,258	1,090,767	1,518,156	4.49	338,119
2013	1,298,830.51	927,105	516,406	782,425	5.01	156,173
2014	85,274.96	57,373	31,957	53,318	5.59	9,538
2015	1,101,904.94	691,886	385,387	716,518	6.22	115,196
2016	696,097.15	402,066	223,954	472,143	6.95	67,934
2017	1,098,229.00	575,911	320,788	777,441	7.71	100,835
2018	1,123,894.11	525,083	292,476	831,418	8.55	97,242
2019	2,500,726.73	1,019,296	567,757	1,932,970	9.45	204,547
2020	2,700,294.24	934,302	520,414	2,179,880	10.40	209,604
2021	2,390,681.37	677,758	377,517	2,013,164	11.37	177,059
2022	1,549,777.67	342,191	190,603	1,359,174	12.35	110,055
2023	1,782,623.74	281,298	156,685	1,625,938	13.35	121,793
2024	1,288,296.26	121,873	67,884	1,220,412	14.35	85,046
2025	387,546.05	12,246	6,821	380,725	15.35	24,803
	23,234,481.93	10,651,538	5,933,001	17,301,481		2,215,126
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	32,312.09	31,213	31,838	474	0.92	474
2000	85,693.63	82,223	83,869	1,825	1.07	1,706
2001	490,180.03	465,965	475,292	14,888	1.26	11,816
2002	1,492,633.20	1,402,030	1,430,094	62,540	1.50	41,693
2003	628,620.53	584,617	596,319	32,302	1.67	19,343
2004	2,471,729.47	2,269,048	2,314,466	157,263	1.90	82,770
2005	1,040,735.70	942,074	960,931	79,805	2.12	37,644
2006	1,110,430.16	987,617	1,007,386	103,045	2.39	43,115
2007	1,298,046.31	1,132,416	1,155,083	142,963	2.67	53,544
2008	423,996.07	363,577	370,855	53,142	2.91	18,262
2009	46,783.61	39,060	39,842	6,942	3.26	2,129
2010	221,968.21	179,927	183,528	38,440	3.62	10,619
2011	176,842.91	138,468	141,240	35,603	4.02	8,856
2012	96,274.94	72,264	73,710	22,564	4.49	5,025
2013	68,490.16	48,888	49,867	18,624	5.01	3,717
2014	166,697.23	112,154	114,399	52,298	5.59	9,356
2016	193,253.15	111,623	113,857	79,396	6.95	11,424
2017	979,813.87	513,814	524,099	455,715	7.71	59,107
2018	334,938.54	156,483	159,615	175,323	8.55	20,506

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2019	40,596.18	16,547	16,878	23,718	9.45	2,510
2020	312,422.28	108,098	110,262	202,161	10.40	19,439
2021	547,336.89	155,170	158,276	389,061	11.37	34,218
2022	892,784.28	197,127	201,073	691,711	12.35	56,009
2023	1,677,936.87	264,778	270,078	1,407,859	13.35	105,458
2024	1,555,326.46	147,134	150,079	1,405,247	14.35	97,927
2025	598,190.74	18,903	19,281	578,909	15.35	37,714
	16,984,033.51	10,541,218	10,752,216	6,231,818		794,381
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1986	6,845.85	6,846	6,846			
1988	2,865.11	2,865	2,865			
1989	1,391.92	1,392	1,392			
1991	2,630.18	2,630	2,630			
1992	212.29	212	212			
1993	424.58	425	425			
2009	396,383.10	330,940	336,896	59,487	3.26	18,248
2020	5,164.22	1,787	1,819	3,345	10.40	322
2021	5,127.99	1,454	1,480	3,648	11.37	321
	421,045.24	348,551	354,565	66,480		18,891
	40,639,560.68	21,541,307	17,039,782	23,599,779		3,028,398

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.8 7.45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	101,732.53	82,313	92,399	9,334	8.59	1,087
1972	93,455.11	74,847	84,018	9,437	8.96	1,053
1973	127,135.54	100,747	113,092	14,044	9.34	1,504
1974	135,075.88	105,870	118,842	16,233	9.73	1,668
1975	92,936.59	72,016	80,840	12,096	10.13	1,194
1976	48,364.14	37,026	41,563	6,801	10.55	645
1977	83,542.25	63,176	70,917	12,625	10.97	1,151
1978	97,632.01	72,876	81,806	15,826	11.41	1,387
1979	306,516.75	225,731	253,390	53,127	11.86	4,480
1980	578,785.99	420,199	471,687	107,099	12.33	8,686
1981	653,208.51	467,260	524,514	128,694	12.81	10,046
1982	524,387.93	410,491	460,789	63,599	12.00	5,300
1983	544,482.64	420,994	472,579	71,903	12.39	5,803
1984	476,450.45	363,579	408,129	68,321	12.81	5,333
1985	668,713.44	503,341	565,016	103,697	13.22	7,844
1986	684,038.52	504,752	566,600	117,438	13.94	8,425
1987	765,418.74	556,306	624,471	140,948	14.38	9,802
1988	985,892.19	705,110	791,508	194,384	14.83	13,107
1989	1,070,134.50	752,519	844,727	225,408	15.30	14,733
1990	1,334,644.62	922,106	1,035,093	299,551	15.77	18,995
1991	1,328,153.09	900,753	1,011,124	317,029	16.25	19,509
1992	1,244,966.55	827,903	929,347	315,619	16.75	18,843
1993	967,023.30	629,919	707,104	259,919	17.26	15,059
1994	1,371,891.22	874,581	981,745	390,146	17.77	21,955
1995	1,516,299.40	944,958	1,060,745	455,554	18.29	24,907
1996	1,411,075.57	858,498	963,691	447,384	18.83	23,759
1997	1,661,272.15	985,467	1,106,218	555,054	19.37	28,655
1998	1,836,056.22	1,060,690	1,190,658	645,398	19.92	32,399
1999	1,801,930.71	1,012,325	1,136,367	665,564	20.48	32,498
2000	1,835,296.69	1,005,559	1,128,772	706,525	20.83	33,919
2001	1,780,558.22	945,654	1,061,527	719,032	21.41	33,584
2002	1,029,425.71	528,919	593,728	435,697	22.00	19,804
2003	1,431,100.42	710,112	797,123	633,977	22.59	28,064
2004	1,123,563.48	537,176	602,997	520,566	23.20	22,438
2005	1,297,983.39	599,279	672,710	625,274	23.61	26,483
2006	1,361,922.07	603,059	676,953	684,969	24.23	28,269
2007	7,191,674.98	3,044,955	3,418,059	3,773,616	24.85	151,856
2008	3,024,995.30	1,238,736	1,390,521	1,634,475	25.24	64,757
2009	2,217,742.35	863,589	969,406	1,248,336	25.87	48,254
2011	1,800,694.03	629,162	706,254	1,094,440	27.00	40,535
2012	2,221,300.70	731,696	821,352	1,399,949	27.48	50,944

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	2,737,348.87	845,293	948,868	1,788,481	27.98	63,920
2014	2,031,120.21	583,947	655,499	1,375,621	28.50	48,267
2015	2,708,188.69	719,295	807,432	1,900,757	29.03	65,476
2016	2,890,225.25	702,903	789,031	2,101,194	29.56	71,082
2017	2,912,602.40	643,685	722,557	2,190,046	29.96	73,099
2018	3,947,225.70	778,393	873,771	3,073,455	30.52	100,703
2019	2,989,579.81	518,991	582,584	2,406,996	30.95	77,770
2020	1,914,224.80	286,368	321,457	1,592,768	31.26	50,952
2021	4,728,885.38	589,219	661,417	4,067,468	31.60	128,717
2022	5,660,278.54	560,368	629,031	5,031,248	31.84	158,017
2023	9,101,328.88	664,397	745,807	8,355,522	31.75	263,166
2024	5,586,664.09	254,752	285,967	5,300,697	31.39	168,866
2025	4,062,914.48	67,444	75,708	3,987,206	29.62	134,612
	100,098,060.98	33,609,304	37,727,512	62,370,549		2,293,381
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1977	203.20	154	182	21	10.97	2
1978	411.20	307	363	48	11.41	4
1979	958.15	706	836	122	11.86	10
1980	1,782.81	1,294	1,532	251	12.33	20
1981	1,056.40	756	895	161	12.81	13
1982	13,798.46	10,801	12,788	1,010	12.00	84
1983	212.09	164	194	18	12.39	1
1984	8,513.78	6,497	7,693	821	12.81	64
1985	147.05	111	131	16	13.22	1
1986	1,429.93	1,055	1,249	181	13.94	13
1987	1,752.16	1,273	1,507	245	14.38	17
2000	4,313.02	2,363	2,798	1,515	20.83	73
2001	1,685.98	895	1,060	626	21.41	29
2006	1,114.00	493	584	530	24.23	22
2007	1,136,336.86	481,125	569,657	566,680	24.85	22,804
2008	939,364.72	384,670	455,453	483,912	25.24	19,172
2009	650,372.98	253,255	299,856	350,517	25.87	13,549
2010	631,510.63	233,912	276,954	354,557	26.34	13,461
2011	777,699.22	271,728	321,729	455,971	27.00	16,888
2012	846,480.92	278,831	330,139	516,342	27.48	18,790
2013	631,712.75	195,073	230,968	400,744	27.98	14,323

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2014	470,931.14	135,393	160,307	310,625	28.50	10,899
2015	391,695.93	104,034	123,177	268,519	29.03	9,250
2016	523,048.03	127,205	150,612	372,436	29.56	12,599
2017	1,022,735.99	226,025	267,616	755,120	29.96	25,204
2018	663,270.02	130,797	154,865	508,405	30.52	16,658
2019	1,194,682.00	207,397	245,560	949,122	30.95	30,666
2020	703,472.09	105,239	124,604	578,868	31.26	18,518
2021	910,882.36	113,496	134,380	776,502	31.60	24,573
2022	2,566,572.37	254,091	300,846	2,265,726	31.84	71,160
2023	4,016,474.39	293,203	347,155	3,669,319	31.75	115,569
2024	2,208,127.70	100,691	119,219	2,088,909	31.39	66,547
2025	654,919.93	10,872	12,873	642,047	29.62	21,676
	20,977,668.26	3,933,906	4,657,782	16,319,886		542,659
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	20,513.54	16,598	13,250	7,264	8.59	846
1972	10,455.25	8,374	6,685	3,771	8.96	421
1973	80,178.92	63,537	50,719	29,459	9.34	3,154
1974	19,775.07	15,499	12,372	7,403	9.73	761
1975	7,664.96	5,940	4,742	2,923	10.13	289
1976	1,436.84	1,100	878	559	10.55	53
1977	8.42	6	5	4	10.97	
1978	952.25	711	568	385	11.41	34
1979	10,350.87	7,623	6,085	4,266	11.86	360
1980	35,806.28	25,995	20,751	15,055	12.33	1,221
1981	32,976.06	23,589	18,830	14,146	12.81	1,104
1982	30,298.97	23,718	18,933	11,366	12.00	947
1983	31,176.75	24,106	19,243	11,934	12.39	963
1984	53,622.36	40,919	32,664	20,958	12.81	1,636
1985	58,717.94	44,197	35,281	23,437	13.22	1,773
1986	74,450.88	54,937	43,854	30,597	13.94	2,195
1987	57,001.64	41,429	33,071	23,930	14.38	1,664
1988	79,399.51	56,787	45,331	34,068	14.83	2,297
1989	83,514.40	58,727	46,880	36,635	15.30	2,394
1990	86,051.49	59,453	47,459	38,592	15.77	2,447
1991	70,069.58	47,521	37,934	32,135	16.25	1,978
1992	76,473.21	50,855	40,596	35,877	16.75	2,142

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1993	102,807.08	66,969	53,459	49,348	17.26	2,859
1994	111,230.16	70,909	56,604	54,626	17.77	3,074
1995	206,710.67	128,822	102,834	103,876	18.29	5,679
1996	304,270.86	185,118	147,774	156,497	18.83	8,311
1997	540,842.00	320,827	256,105	284,737	19.37	14,700
1998	384,281.86	222,000	177,215	207,067	19.92	10,395
1999	387,269.82	217,568	173,677	213,593	20.48	10,429
2000	325,954.48	178,590	142,562	183,392	20.83	8,804
2001	280,806.68	149,136	119,050	161,756	21.41	7,555
2002	344,298.06	176,900	141,213	203,085	22.00	9,231
2003	400,218.79	198,589	158,527	241,692	22.59	10,699
2004	370,896.43	177,326	141,553	229,343	23.20	9,885
2005	412,757.13	190,570	152,126	260,631	23.61	11,039
2006	677,859.46	300,156	239,605	438,255	24.23	18,087
2007	479,038.21	202,825	161,908	317,130	24.85	12,762
2008	841,575.58	344,625	275,103	566,473	25.24	22,443
2009	330,126.13	128,551	102,618	227,508	25.87	8,794
2010	399,134.86	147,840	118,016	281,119	26.34	10,673
2011	792,876.19	277,031	221,145	571,732	27.00	21,175
2012	632,492.13	208,343	166,313	466,179	27.48	16,964
2013	755,842.89	233,404	186,319	569,524	27.98	20,355
2014	1,063,981.95	305,895	244,186	819,796	28.50	28,765
2015	2,023,580.62	537,463	429,039	1,594,542	29.03	54,927
2016	655,151.02	159,333	127,190	527,961	29.56	17,861
2017	711,155.40	157,165	125,460	585,696	29.96	19,549
2018	1,269,033.32	250,253	199,769	1,069,265	30.52	35,035
2019	557,792.31	96,833	77,299	480,494	30.95	15,525
2020	18,843.96	2,819	2,250	16,594	31.26	531
2021	1,153,934.02	143,780	114,775	1,039,159	31.60	32,885
2022	761,105.97	75,349	60,149	700,957	31.84	22,015
2023	669,224.97	48,853	38,998	630,227	31.75	19,850
2024	1,072,817.12	48,920	39,051	1,033,766	31.39	32,933
2025	877,448.17	14,566	11,628	865,821	29.62	29,231
	20,836,253.49	6,638,949	5,299,652	15,536,602		581,699
	141,911,982.73	44,182,159	47,684,946	94,227,037		3,417,739

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.6 2.41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1944	77.95	77	14	64	0.59	64
1957	117.06	106	19	98	4.21	23
1962	2,151.47	1,880	340	1,812	5.67	320
1964	17,920.86	15,420	2,785	15,135	6.28	2,410
1965	20,920.63	17,857	3,226	17,695	6.59	2,685
1966	29,758.73	25,196	4,551	25,207	6.90	3,653
1967	33,875.31	28,440	5,137	28,738	7.22	3,980
1968	27,894.47	23,214	4,193	23,701	7.55	3,139
1969	29,312.36	24,173	4,367	24,946	7.89	3,162
1970	46,449.79	37,944	6,854	39,596	8.24	4,805
1971	42,432.58	34,333	6,202	36,231	8.59	4,218
1972	30,600.18	24,507	4,427	26,173	8.96	2,921
1973	21,528.93	17,060	3,082	18,447	9.34	1,975
1974	24,295.63	19,042	3,440	20,856	9.73	2,143
1975	33,447.98	25,919	4,682	28,766	10.13	2,840
1976	7,088.04	5,426	980	6,108	10.55	579
1977	17,783.83	13,448	2,429	15,355	10.97	1,400
1978	23,253.21	17,357	3,135	20,118	11.41	1,763
1979	84,123.28	61,952	11,191	72,932	11.86	6,149
1980	175,119.76	127,137	22,966	152,154	12.33	12,340
1981	85,224.43	60,964	11,013	74,212	12.81	5,793
1982	129,428.81	101,317	18,302	111,127	12.00	9,261
1983	63,138.87	48,819	8,819	54,320	12.39	4,384
1984	58,876.10	44,928	8,116	50,760	12.81	3,963
1985	123,384.92	92,872	16,777	106,608	13.22	8,064
1986	140,377.12	103,584	18,712	121,666	13.94	8,728
1987	136,832.49	99,450	17,965	118,868	14.38	8,266
1988	175,491.48	125,512	22,673	152,819	14.83	10,305
1989	213,503.89	150,136	27,121	186,383	15.30	12,182
1990	214,130.92	147,943	26,725	187,406	15.77	11,884
1991	78,271.51	53,084	9,589	68,682	16.25	4,227
1992	96,689.87	64,299	11,615	85,075	16.75	5,079
1993	33,962.96	22,123	3,996	29,967	17.26	1,736
1994	111,740.54	71,235	12,868	98,873	17.77	5,564
1995	158,945.89	99,055	17,893	141,052	18.29	7,712
1996	44,731.50	27,215	4,916	39,815	18.83	2,114
1997	90,392.75	53,621	9,686	80,707	19.37	4,167
1998	55,905.23	32,296	5,834	50,071	19.92	2,514
1999	104,475.10	58,694	10,603	93,873	20.48	4,584
2000	92,875.32	50,886	9,192	83,683	20.83	4,017
2001	170,338.61	90,467	16,342	153,997	21.41	7,193

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2002	54,814.24	28,164	5,088	49,727	22.00	2,260
2003	133,190.26	66,089	11,938	121,252	22.59	5,368
2004	229,781.29	109,858	19,845	209,936	23.20	9,049
2005	221,319.48	102,183	18,458	202,861	23.61	8,592
2006	179,516.35	79,490	14,359	165,157	24.23	6,816
2008	542,890.68	222,314	40,159	502,732	25.24	19,918
2009	435,453.99	169,566	30,631	404,823	25.87	15,648
2010	540,142.20	200,069	36,141	504,001	26.34	19,134
2012	185,684.69	61,165	11,049	174,636	27.48	6,355
2013	64,891.21	20,038	3,620	61,272	27.98	2,190
2020	80,753.41	12,081	2,182	78,571	31.26	2,513
2022	23,952.58	2,371	428	23,524	31.84	739
2023	58,165.17	4,246	767	57,398	31.75	1,808
2024	30,384.42	1,386	250	30,134	31.39	960
2025	60,929.95	1,011	183	60,747	29.62	2,051
	5,888,740.28	3,199,019	577,875	5,310,865		295,707
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1950	211.54	201	212			
1952	22,872.17	21,464	22,872			
1953	3,324.65	3,099	3,325			
1954	3,638.77	3,369	3,639			
1956	2,288.98	2,090	2,289			
1957	4,312.96	3,909	4,313			
1958	523.27	471	523			
1959	5,076.98	4,537	5,077			
1960	13,576.34	12,041	13,576			
1961	9,266.15	8,158	9,266			
1962	28,692.16	25,077	28,692			
1963	14,471.10	12,551	14,471			
1964	37,803.93	32,528	37,804			
1965	38,378.73	32,759	38,379			
1966	31,246.60	26,456	31,247			
1967	24,202.13	20,319	24,202			
1968	19,889.94	16,553	19,890			
1969	19,954.10	16,456	19,954			
1970	22,762.73	18,595	22,763			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	20,289.92	16,417	20,290			
1972	17,294.88	13,851	17,295			
1973	11,492.55	9,107	11,493			
1974	24,418.58	19,139	24,419			
1975	16,319.18	12,646	16,319			
1976	25,023.29	19,157	25,023			
1977	43,118.59	32,607	43,119			
1978	25,979.99	19,393	25,980			
1979	50,315.47	37,054	49,968	348	11.86	29
1980	157,640.32	114,447	154,334	3,307	12.33	268
1981	85,258.09	60,988	82,243	3,015	12.81	235
1984	251.00	192	251			
1985	76,948.28	57,919	76,948			
1986	6,297.30	4,647	6,272	26	13.94	2
1987	4,517.67	3,283	4,431	87	14.38	6
1988	436.80	312	421	16	14.83	1
1989	61,414.76	43,187	58,285	3,130	15.30	205
1990	113,229.49	78,230	105,579	7,650	15.77	485
1991	3,009.98	2,041	2,755	255	16.25	16
1992	70,156.42	46,654	62,964	7,192	16.75	429
1993	67,108.70	43,715	58,998	8,111	17.26	470
1994	82,593.19	52,653	71,061	11,533	17.77	649
1995	26,780.69	16,690	22,525	4,256	18.29	233
1996	1,225.32	745	1,005	220	18.83	12
1997	216,693.86	128,543	173,482	43,212	19.37	2,231
1998	256,742.97	148,320	200,173	56,570	19.92	2,840
1999	8,429.94	4,736	6,392	2,038	20.48	100
2000	84,587.64	46,346	62,549	22,039	20.83	1,058
2001	118,361.21	62,862	84,839	33,523	21.41	1,566
2002	169,552.53	87,116	117,572	51,981	22.00	2,363
2003	148,288.73	73,581	99,305	48,984	22.59	2,168
2004	220,104.20	105,232	142,021	78,083	23.20	3,366
2007	122,142.22	51,715	69,795	52,348	24.85	2,107
2009	114,064.35	44,417	59,945	54,119	25.87	2,092
2010	62,519.49	23,157	31,253	31,267	26.34	1,187
2018	45.98	9	12	34	30.52	1
2022	6,986.91	692	934	6,053	31.84	190

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2023	18,231.73	1,331	1,796	16,435	31.75	518
2024	57,581.69	2,626	3,544	54,038	31.39	1,722
2025	18,398.87	305	412	17,987	29.62	607
	2,916,346.01	1,746,695	2,298,491	617,855		27,156
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1970	5,001.66	4,086	5,002			
1971	12,065.77	9,763	12,066			
1972	16,158.21	12,941	16,158			
1973	23,610.65	18,710	23,611			
1974	11,934.41	9,354	11,934			
1975	6,620.80	5,130	6,608	12	10.13	1
1976	3,884.68	2,974	3,831	54	10.55	5
1977	5,230.27	3,955	5,095	136	10.97	12
1978	5,706.05	4,259	5,486	220	11.41	19
1979	25,223.43	18,576	23,929	1,294	11.86	109
1980	21,935.83	15,925	20,514	1,422	12.33	115
1981	13,794.39	9,868	12,712	1,083	12.81	85
1982	18,523.58	14,500	18,524			
1983	29,007.23	22,428	28,896	111	12.39	9
1984	25,172.95	19,209	24,749	424	12.81	33
1985	27,049.72	20,360	26,232	818	13.22	62
1986	27,469.49	20,270	26,116	1,354	13.94	97
1987	27,188.25	19,760	25,459	1,729	14.38	120
1988	33,227.77	23,765	30,619	2,609	14.83	176
1989	49,270.86	34,647	44,639	4,632	15.30	303
1990	52,753.58	36,447	46,958	5,795	15.77	367
1991	51,222.02	34,739	44,758	6,464	16.25	398
1992	54,594.81	36,306	46,777	7,818	16.75	467
1993	58,410.15	38,048	49,021	9,389	17.26	544
1994	72,041.99	45,927	59,172	12,870	17.77	724
1995	66,567.19	41,485	53,449	13,118	18.29	717
1996	69,627.81	42,362	54,579	15,049	18.83	799
1997	42,597.30	25,269	32,557	10,041	19.37	518
1998	67,630.64	39,070	50,338	17,293	19.92	868
1999	15,985.66	8,981	11,571	4,415	20.48	216
2000	19,079.45	10,454	13,469	5,611	20.83	269

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	14,019.42	7,446	9,593	4,426	21.41	207
2002	20,738.40	10,655	13,728	7,010	22.00	319
2003	16,488.67	8,182	10,542	5,947	22.59	263
2004	16,273.80	7,781	10,025	6,249	23.20	269
2005	8,074.49	3,728	4,803	3,271	23.61	139
2006	19,031.70	8,427	10,857	8,174	24.23	337
2007	18,179.90	7,697	9,917	8,263	24.85	333
2008	21,615.63	8,852	11,405	10,211	25.24	405
2009	25,708.61	10,011	12,898	12,810	25.87	495
2010	17,915.17	6,636	8,550	9,365	26.34	356
2011	25,078.47	8,762	11,289	13,790	27.00	511
2012	43,118.70	14,203	18,299	24,820	27.48	903
2013	31,965.64	9,871	12,718	19,248	27.98	688
2014	28,084.77	8,074	10,403	17,682	28.50	620
2015	17,007.06	4,517	5,820	11,187	29.03	385
2016	34,471.28	8,383	10,801	23,671	29.56	801
2017	118,289.24	26,142	33,681	84,608	29.96	2,824
2018	11,207.60	2,210	2,847	8,360	30.52	274
2019	341.14	59	76	265	30.95	9
2021	2,474.84	308	397	2,078	31.60	66
2022	3,340.12	331	426	2,914	31.84	92
2023	4,497.06	328	423	4,074	31.75	128
2024	3,946.39	180	232	3,714	31.39	118
2025	8,582.07	142	183	8,399	29.62	284
	1,469,036.77	812,493	1,044,741	424,295		17,859
	10,274,123.06	5,758,207	3,921,108	6,353,015		340,722

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.6 3.32

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	32,099.03	25,972	29,425	2,674	8.59	311
1972	38,136.64	30,543	34,604	3,533	8.96	394
1973	46,699.12	37,006	41,926	4,773	9.34	511
1974	41,287.45	32,360	36,662	4,625	9.73	475
1975	28,525.71	22,104	25,043	3,483	10.13	344
1976	20,710.12	15,855	17,963	2,747	10.55	260
1977	30,396.78	22,987	26,043	4,354	10.97	397
1978	40,769.14	30,432	34,478	6,291	11.41	551
1979	68,832.87	50,691	57,431	11,402	11.86	961
1980	131,408.86	95,403	108,087	23,322	12.33	1,891
1981	110,631.00	79,138	89,660	20,971	12.81	1,637
1982	190,335.00	148,994	168,803	21,532	12.00	1,794
1983	141,533.91	109,434	123,984	17,550	12.39	1,416
1984	96,589.58	73,708	83,508	13,082	12.81	1,021
1985	157,339.96	118,430	134,176	23,164	13.22	1,752
1986	142,951.52	105,484	119,509	23,443	13.94	1,682
1987	168,313.63	122,330	138,594	29,719	14.38	2,067
1988	176,855.08	126,487	143,304	33,551	14.83	2,262
1989	245,809.88	172,854	195,836	49,974	15.30	3,266
1990	200,239.89	138,346	156,740	43,500	15.77	2,758
1991	127,914.76	86,752	98,286	29,629	16.25	1,823
1992	194,224.55	129,159	146,331	47,893	16.75	2,859
1993	110,374.14	71,898	81,457	28,917	17.26	1,675
1994	159,243.25	101,518	115,015	44,228	17.77	2,489
1995	225,556.84	140,567	159,256	66,301	18.29	3,625
1996	146,163.86	88,926	100,749	45,415	18.83	2,412
1997	183,670.61	108,953	123,439	60,232	19.37	3,110
1998	242,997.43	140,380	159,044	83,953	19.92	4,215
1999	163,009.46	91,579	103,755	59,255	20.48	2,893
2000	129,708.02	71,067	80,516	49,192	20.83	2,362
2001	175,354.91	93,131	105,513	69,842	21.41	3,262
2002	178,137.48	91,527	103,696	74,442	22.00	3,384
2003	463,652.54	230,064	260,652	203,000	22.59	8,986
2004	582,927.65	278,698	315,752	267,175	23.20	11,516
2005	461,613.81	213,127	241,463	220,151	23.61	9,324
2006	271,218.43	120,096	136,063	135,155	24.23	5,578
2008	801,363.82	328,158	371,788	429,576	25.24	17,020
2009	189,343.07	73,730	83,533	105,810	25.87	4,090
2010	213,698.43	79,154	89,678	124,021	26.34	4,708
2011	310,820.65	108,601	123,040	187,781	27.00	6,955
2012	514,236.52	169,390	191,911	322,325	27.48	11,729

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2013	418,060.32	129,097	146,261	271,799	27.98	9,714
2014	466,917.86	134,239	152,087	314,831	28.50	11,047
2015	456,957.65	121,368	137,504	319,453	29.03	11,004
2016	686,364.70	166,924	189,117	497,247	29.56	16,822
2017	746,787.10	165,040	186,983	559,804	29.96	18,685
2018	883,633.27	174,252	197,420	686,214	30.52	22,484
2019	540,738.04	93,872	106,353	434,385	30.95	14,035
2020	181,428.19	27,142	30,751	150,678	31.26	4,820
2021	270,428.66	33,695	38,175	232,254	31.60	7,350
2022	38,388.69	3,800	4,305	34,083	31.84	1,070
2023	2,635.29	192	218	2,418	31.75	76
2024	3,310.00	151	171	3,139	31.39	100
2025	219,866.82	3,650	4,135	215,732	29.62	7,283
	12,870,211.99	5,428,455	6,150,194	6,720,018		264,255
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1972	13,313.98	10,663	13,314			
1973	38,836.17	30,775	38,836			
1974	144,406.45	113,183	144,406			
1975	99,258.76	76,915	99,259			
1976	162,178.02	124,157	160,278	1,900	10.55	180
1977	227,638.93	172,145	222,227	5,412	10.97	493
1978	126,268.54	94,252	121,673	4,596	11.41	403
1979	78,656.93	57,926	74,778	3,878	11.86	327
1980	57,030.55	41,404	53,450	3,581	12.33	290
1981	109,907.92	78,620	101,493	8,415	12.81	657
1985	24,654.43	18,557	23,956	699	13.22	53
1986	27,447.15	20,253	26,145	1,302	13.94	93
1988	68,000.86	48,634	62,783	5,218	14.83	352
1989	58,448.77	41,101	53,059	5,390	15.30	352
1990	51,140.66	35,333	45,612	5,528	15.77	351
1991	39,011.61	26,458	34,155	4,856	16.25	299
1992	35,854.73	23,843	30,780	5,075	16.75	303
1993	51,676.44	33,662	43,455	8,221	17.26	476
1994	71,235.62	45,413	58,625	12,611	17.77	710
1995	49,500.84	30,849	39,824	9,677	18.29	529
1996	45,909.70	27,931	36,057	9,853	18.83	523

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1997	34,534.58	20,486	26,446	8,089	19.37	418
1998	49,970.37	28,868	37,267	12,704	19.92	638
1999	46,832.83	26,311	33,966	12,867	20.48	628
2000	39,699.21	21,751	28,079	11,620	20.83	558
2001	45,124.99	23,966	30,938	14,187	21.41	663
2002	66,517.98	34,177	44,120	22,398	22.00	1,018
2003	78,667.19	39,035	50,391	28,276	22.59	1,252
2004	165,793.01	79,266	102,327	63,466	23.20	2,736
2005	119,365.27	55,111	71,144	48,221	23.61	2,042
2006	70,424.87	31,184	40,256	30,168	24.23	1,245
2007	97,997.49	41,492	53,563	44,434	24.85	1,788
2008	109,845.80	44,982	58,069	51,777	25.24	2,051
2009	119,208.92	46,420	59,925	59,284	25.87	2,292
2010	90,572.74	33,548	43,308	47,265	26.34	1,794
2011	78,430.71	27,404	35,377	43,054	27.00	1,595
2012	113,394.32	37,352	48,219	65,175	27.48	2,372
2013	103,879.46	32,078	41,410	62,469	27.98	2,233
2014	114,396.21	32,889	42,457	71,939	28.50	2,524
2015	12,301.93	3,267	4,217	8,084	29.03	278
2016	95,701.05	23,274	30,045	65,656	29.56	2,221
2017	88,931.16	19,654	25,372	63,559	29.96	2,121
2018	56,220.18	11,087	14,313	41,908	30.52	1,373
2019	45,274.31	7,860	10,147	35,128	30.95	1,135
2020	38,662.29	5,784	7,467	31,196	31.26	998
2024	14,048.80	641	827	13,221	31.39	421
	3,476,172.73	1,879,961	2,423,818	1,052,355		42,785
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	5,439.90	4,401	5,004	435	8.59	51
1972	14,933.80	11,960	13,600	1,334	8.96	149
1973	7,861.73	6,230	7,084	777	9.34	83
1974	9,613.04	7,535	8,568	1,045	9.73	107
1975	4,932.44	3,822	4,346	586	10.13	58
1976	4,347.30	3,328	3,784	563	10.55	53
1977	3,525.43	2,666	3,032	494	10.97	45
1978	2,829.16	2,112	2,402	428	11.41	38
1979	3,571.30	2,630	2,991	581	11.86	49

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1980	10,155.76	7,373	8,384	1,772	12.33	144
1981	8,768.97	6,273	7,133	1,636	12.81	128
1982	7,863.13	6,155	6,999	864	12.00	72
1983	27,433.37	21,211	24,119	3,314	12.39	267
1984	14,612.72	11,151	12,680	1,933	12.81	151
1985	17,814.51	13,409	15,248	2,567	13.22	194
1986	8,715.77	6,431	7,313	1,403	13.94	101
1987	6,897.76	5,013	5,700	1,197	14.38	83
1988	18,499.00	13,230	15,044	3,455	14.83	233
1989	17,820.76	12,532	14,250	3,570	15.30	233
1990	13,760.77	9,507	10,811	2,950	15.77	187
1991	16,073.60	10,901	12,396	3,678	16.25	226
1992	6,559.93	4,362	4,960	1,600	16.75	96
1993	29,217.11	19,032	21,642	7,576	17.26	439
1994	25,165.33	16,043	18,243	6,923	17.77	390
1995	58,774.81	36,628	41,650	17,125	18.29	936
1996	115,510.48	70,277	79,913	35,597	18.83	1,890
1997	68,827.66	40,829	46,427	22,400	19.37	1,156
1998	53,919.97	31,150	35,421	18,499	19.92	929
1999	48,940.91	27,495	31,265	17,676	20.48	863
2000	55,190.97	30,239	34,385	20,806	20.83	999
2001	36,718.99	19,501	22,175	14,544	21.41	679
2002	75,211.94	38,644	43,943	31,269	22.00	1,421
2003	104,709.50	51,957	59,081	45,628	22.59	2,020
2004	98,717.26	47,197	53,668	45,049	23.20	1,942
2005	53,701.30	24,794	28,194	25,508	23.61	1,080
2006	64,103.29	28,385	32,277	31,826	24.23	1,313
2007	57,266.33	24,247	27,572	29,695	24.85	1,195
2008	105,754.48	43,306	49,244	56,511	25.24	2,239
2009	77,881.91	30,327	34,485	43,397	25.87	1,678
2010	36,000.84	13,335	15,163	20,837	26.34	791
2011	9,612.23	3,359	3,820	5,793	27.00	215
2012	1,472.30	485	552	921	27.48	34
2013	2,742.40	847	963	1,779	27.98	64
2014	4,238.77	1,219	1,386	2,853	28.50	100
2015	13,257.55	3,521	4,004	9,254	29.03	319
2016	6,407.77	1,558	1,772	4,636	29.56	157
2017	3,451.34	763	868	2,584	29.96	86
2018	17,977.88	3,545	4,031	13,947	30.52	457

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2019	421.75	73	83	339	30.95	11
2020	197.26	30	34	163	31.26	5
2024	25,549.95	1,165	1,325	24,225	31.39	772
	1,482,972.43	782,183	889,433	593,540		26,928
	17,829,357.15	8,090,599	9,463,445	8,365,913		333,968
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					25.1	1.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	645	692			
1956	2,239.85	2,045	2,240			
1957	4,785.87	4,338	4,786			
1960	16,750.58	14,856	16,751			
1961	12,800.59	11,270	12,801			
1962	22,033.72	19,257	22,034			
1963	24,186.10	20,977	24,116	70	5.97	12
1964	21,937.83	18,876	21,701	237	6.28	38
1965	14,345.92	12,245	14,078	268	6.59	41
1966	22,819.15	19,320	22,211	608	6.90	88
1967	33,625.63	28,231	32,456	1,170	7.22	162
1968	78,227.64	65,103	74,846	3,381	7.55	448
1969	79,698.42	65,725	75,561	4,137	7.89	524
1970	56,628.40	46,259	53,182	3,446	8.24	418
1971	50,484.00	40,847	46,960	3,524	8.59	410
1972	74,487.40	59,656	68,584	5,903	8.96	659
1973	5,856.45	4,641	5,336	521	9.34	56
1974	2,435.60	1,909	2,195	241	9.73	25
1975	3,447.78	2,672	3,072	376	10.13	37
1976	1,925.80	1,474	1,695	231	10.55	22
1979	129,595.68	95,439	109,723	19,873	11.86	1,676
1980	273,942.52	198,882	228,647	45,296	12.33	3,674
1981	280,781.60	200,852	230,912	49,870	12.81	3,893
1982	232,089.47	181,680	208,870	23,219	12.00	1,935
1983	89,210.82	68,978	79,301	9,909	12.39	800
1984	47,248.78	36,056	41,452	5,797	12.81	453
1985	101,055.89	76,065	87,449	13,607	13.22	1,029
1986	78,585.49	57,988	66,667	11,919	13.94	855
1987	157,570.97	114,523	131,663	25,908	14.38	1,802
1988	283,620.35	202,845	233,203	50,417	14.83	3,400
1989	183,420.00	128,981	148,284	35,136	15.30	2,296
1990	203,975.86	140,927	162,018	41,958	15.77	2,661
1991	221,578.38	150,274	172,764	48,814	16.25	3,004
1992	121,714.83	80,940	93,054	28,661	16.75	1,711
1993	67,829.07	44,184	50,797	17,032	17.26	987
1994	215,739.93	137,534	158,118	57,622	17.77	3,243
1995	283,678.95	176,789	203,247	80,431	18.29	4,398
1996	638,322.65	388,356	446,478	191,845	18.83	10,188
1997	114,991.22	68,213	78,422	36,569	19.37	1,888
1998	89,135.98	51,494	59,201	29,935	19.92	1,503
1999	211,901.85	119,046	136,863	75,039	20.48	3,664

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2000	61,111.51	33,483	38,494	22,617	20.83	1,086
2001	5,688.76	3,021	3,473	2,216	21.41	104
2002	124,248.21	63,839	73,393	50,855	22.00	2,312
2005	16,976.59	7,838	9,011	7,966	23.61	337
2007	36,240.36	15,344	17,640	18,600	24.85	748
2008	123,273.33	50,480	58,035	65,238	25.24	2,585
2012	13,100.09	4,315	4,961	8,139	27.48	296
2014	217,660.91	62,578	71,944	145,717	28.50	5,113
2015	137,276.88	36,461	41,918	95,359	29.03	3,285
2016	122,361.10	29,758	34,212	88,149	29.56	2,982
2017	542,789.02	119,956	137,909	404,880	29.96	13,514
2018	224,701.21	44,311	50,943	173,759	30.52	5,693
2019	656,174.48	113,912	130,960	525,214	30.95	16,970
2020	2,116,662.54	316,653	364,044	1,752,619	31.26	56,066
2021	1,046,978.33	130,453	149,977	897,002	31.60	28,386
2023	75,522.95	5,513	6,338	69,185	31.75	2,179
2024	130,066.51	5,931	6,819	123,248	31.39	3,926
2025	120,110.28	1,994	2,292	117,818	29.62	3,978
	10,326,341.61	4,206,232	4,834,789	5,491,552		207,560
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	796	860			
1956	7,054.30	6,440	7,054			
1957	11,192.51	10,145	11,193			
1958	5,050.93	4,546	5,051			
1959	689.61	616	690			
1960	32,725.24	29,024	32,725			
1961	10,605.59	9,338	10,606			
1962	22,867.17	19,986	22,867			
1963	60,787.04	52,722	60,787			
1964	79,108.77	68,068	79,109			
1965	131,939.84	112,619	131,940			
1966	124,040.09	105,021	124,040			
1967	208,085.37	174,700	208,085			
1968	233,579.88	194,390	233,203	376	7.55	50
1969	194,219.76	160,167	192,147	2,073	7.89	263
1970	271,294.84	221,618	265,868	5,427	8.24	659

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1971	229,764.59	185,905	223,024	6,740	8.59	785
1972	257,964.38	206,601	247,853	10,112	8.96	1,129
1973	108,983.37	86,363	103,607	5,376	9.34	576
1974	90,753.81	71,131	85,334	5,420	9.73	557
1975	52,275.40	40,508	48,596	3,679	10.13	363
1976	53,093.99	40,647	48,763	4,331	10.55	411
1977	29,803.40	22,538	27,038	2,765	10.97	252
1978	50,738.04	37,873	45,435	5,303	11.41	465
1979	92,133.69	67,851	81,399	10,735	11.86	905
1980	489,117.73	355,099	426,001	63,117	12.33	5,119
1981	230,826.16	165,117	198,086	32,741	12.81	2,556
1982	80,975.76	63,388	76,045	4,931	12.00	411
1983	42,099.09	32,551	39,050	3,049	12.39	246
1984	46,511.61	35,493	42,580	3,932	12.81	307
1985	72,222.02	54,362	65,216	7,006	13.22	530
1986	43,855.97	32,361	38,822	5,034	13.94	361
1987	107,897.65	78,420	94,078	13,820	14.38	961
1988	160,625.82	114,880	137,818	22,808	14.83	1,538
1989	30,425.01	21,395	25,667	4,758	15.30	311
1990	108,749.56	75,135	90,137	18,613	15.77	1,180
1991	127,229.75	86,287	103,516	23,714	16.25	1,459
1992	44,347.42	29,491	35,379	8,968	16.75	535
1993	29,918.28	19,489	23,380	6,538	17.26	379
1994	29,674.28	18,917	22,694	6,980	17.77	393
1995	34,913.41	21,758	26,102	8,811	18.29	482
1996	43,150.00	26,252	31,494	11,656	18.83	619
1997	147,679.42	87,603	105,095	42,585	19.37	2,199
1998	59,434.64	34,335	41,191	18,244	19.92	916
1999	115,364.91	64,812	77,753	37,612	20.48	1,837
2000	88,357.27	48,411	58,077	30,280	20.83	1,454
2001	81,293.19	43,175	51,796	29,498	21.41	1,378
2002	24,753.36	12,718	15,257	9,496	22.00	432
2003	6,572.47	3,261	3,912	2,660	22.59	118
2004	11,469.43	5,484	6,579	4,890	23.20	211
2005	8,155.02	3,765	4,517	3,638	23.61	154
2006	8,567.60	3,794	4,552	4,016	24.23	166
2007	26,075.02	11,040	13,244	12,831	24.85	516
2008	31,803.84	13,024	15,624	16,179	25.24	641
2009	68,220.04	26,565	31,869	36,351	25.87	1,405
2010	60,218.85	22,305	26,759	33,460	26.34	1,270
2011	489,447.99	171,013	205,159	284,289	27.00	10,529

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2012	154,849.37	51,007	61,191	93,658	27.48	3,408
2013	5,908.18	1,824	2,188	3,720	27.98	133
2014	69,835.34	20,078	24,087	45,748	28.50	1,605
2015	3,012,389.09	800,091	959,843	2,052,546	29.03	70,704
2016	2,481,717.48	603,554	724,064	1,757,653	29.56	59,461
2017	56,121.74	12,403	14,879	41,242	29.96	1,377
2019	397,651.78	69,032	82,815	314,836	30.95	10,172
2024	862,634.10	39,336	47,190	815,444	31.39	25,978
	12,350,671.41	5,308,638	6,350,981	5,999,690		219,866
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1939	90.00	90	90			
1941	90.00	90	90			
1942	132.66	132	133			
1943	519.95	516	520			
1944	66.33	65	66			
1945	197.92	194	198			
1946	210.99	206	211			
1947	189.93	184	190			
1948	87.26	84	87			
1949	87.44	84	87			
1950	87.28	83	87			
1952	1,265.02	1,187	1,265			
1954	1,296.62	1,200	1,297			
1955	1,460.37	1,343	1,459	2	3.63	1
1956	7,995.25	7,299	7,928	67	3.92	17
1957	2,885.06	2,615	2,840	45	4.21	11
1958	2,623.82	2,361	2,564	59	4.50	13
1959	13,164.96	11,764	12,778	387	4.79	81
1960	21,807.35	19,341	21,008	799	5.09	157
1961	5,144.51	4,529	4,919	225	5.38	42
1962	11,141.18	9,737	10,576	565	5.67	100
1963	27,223.97	23,612	25,647	1,577	5.97	264
1964	25,450.83	21,899	23,786	1,664	6.28	265
1965	44,735.37	38,184	41,475	3,260	6.59	495
1966	40,165.22	34,007	36,938	3,227	6.90	468
1967	46,527.03	39,062	42,429	4,098	7.22	568

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1968	40,719.90	33,888	36,809	3,911	7.55	518
1969	46,369.74	38,240	41,536	4,834	7.89	613
1970	37,753.88	30,841	33,499	4,255	8.24	516
1971	16,346.27	13,226	14,366	1,980	8.59	231
1972	17,281.90	13,841	15,034	2,248	8.96	251
1973	15,500.00	12,283	13,342	2,158	9.34	231
1974	23,356.27	18,306	19,884	3,472	9.73	357
1975	7,679.24	5,951	6,464	1,215	10.13	120
1976	8,292.18	6,348	6,895	1,397	10.55	132
1977	4,682.18	3,541	3,846	836	10.97	76
1978	8,792.04	6,563	7,129	1,663	11.41	146
1979	17,159.04	12,637	13,726	3,433	11.86	289
1980	98,862.58	71,774	77,960	20,902	12.33	1,695
1981	107,317.69	76,768	83,385	23,933	12.81	1,868
1982	82,054.88	64,233	69,769	12,286	12.00	1,024
1983	56,055.83	43,342	47,078	8,978	12.39	725
1984	108,966.47	83,152	90,319	18,648	12.81	1,456
1985	78,897.92	59,386	64,504	14,393	13.22	1,089
1986	100,647.04	74,267	80,668	19,979	13.94	1,433
1987	89,032.58	64,709	70,286	18,746	14.38	1,304
1988	201,578.11	144,169	156,595	44,983	14.83	3,033
1989	181,749.75	127,806	138,822	42,928	15.30	2,806
1990	168,687.80	116,546	126,591	42,097	15.77	2,669
1991	259,022.46	175,669	190,810	68,213	16.25	4,198
1992	307,081.30	204,209	221,810	85,272	16.75	5,091
1993	257,960.73	168,036	182,519	75,442	17.26	4,371
1994	299,469.26	190,912	207,367	92,103	17.77	5,183
1995	383,632.67	239,080	259,686	123,946	18.29	6,777
1996	263,623.21	160,388	174,212	89,411	18.83	4,748
1997	602,101.29	357,166	387,950	214,151	19.37	11,056
1998	656,033.57	378,991	411,656	244,377	19.92	12,268
1999	631,187.94	354,601	385,164	246,024	20.48	12,013
2000	507,998.21	278,332	302,321	205,677	20.83	9,874
2001	180,357.98	95,788	104,044	76,314	21.41	3,564
2002	500,472.44	257,143	279,306	221,166	22.00	10,053
2003	1,055,633.43	523,805	568,952	486,682	22.59	21,544
2004	900,236.07	430,403	467,499	432,737	23.20	18,652
2005	519,501.46	239,854	260,527	258,974	23.61	10,969
2006	908,880.25	402,452	437,139	471,741	24.23	19,469
2007	468,347.81	198,298	215,389	252,959	24.85	10,179
2008	726,017.49	297,304	322,929	403,089	25.24	15,970

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2009	490,635.59	191,053	207,520	283,116	25.87	10,944
2010	547,718.42	202,875	220,361	327,358	26.34	12,428
2011	967,649.39	338,097	367,238	600,412	27.00	22,237
2012	442,138.21	145,640	158,193	283,946	27.48	10,333
2013	339,783.84	104,925	113,968	225,815	27.98	8,071
2014	368,076.20	105,822	114,943	253,133	28.50	8,882
2015	393,163.28	104,424	113,424	279,739	29.03	9,636
2016	377,143.86	91,721	99,626	277,517	29.56	9,388
2017	893,117.12	197,379	214,391	678,726	29.96	22,654
2018	1,060,003.81	209,033	227,050	832,954	30.52	27,292
2019	554,738.36	96,303	104,603	450,135	30.95	14,544
2020	67,654.38	10,121	10,993	56,661	31.26	1,813
2021	1,283.34	160	174	1,110	31.60	35
2022	9,408.08	931	1,011	8,397	31.84	264
2023	742.13	54	59	683	31.75	22
2024	58,254.36	2,656	2,885	55,369	31.39	1,764
2025	802.02	13	14	788	29.62	27
	17,772,299.57	8,095,323	8,792,910	8,979,389		371,377
	40,449,312.59	17,610,193	19,978,681	20,470,631		798,803

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.6 1.97

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,667	1,965-	3,934	6.90	570
1967	207.34	174	205-	412	7.22	57
1968	820.82	683	805-	1,626	7.55	215
1969	4,348.68	3,586	4,227-	8,575	7.89	1,087
1970	585.40	478	563-	1,149	8.24	139
1971	1,925.29	1,558	1,836-	3,762	8.59	438
1972	16,780.77	13,440	15,841-	32,622	8.96	3,641
2004	19,260.94	9,209	10,854-	30,115	23.20	1,298
2005	22,925.98	10,585	12,476-	35,402	23.61	1,499
2024	94,400.01	4,305	5,074-	99,474	31.39	3,169
2025	103,838.99	1,724	2,032-	105,871	29.62	3,574
	267,062.91	47,409	55,879-	322,942		15,687

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.6 5.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1929	141.00	141	141			
1955	2,275.45	1,991	2,275			
1956	989.22	860	989			
1957	545.83	471	546			
1958	236.59	203	237			
1959	739.15	628	739			
1960	6,231.82	5,258	6,212	20	7.03	3
1961	5,465.73	4,575	5,405	61	7.33	8
1962	1,776.66	1,476	1,744	33	7.62	4
1963	1,519.13	1,251	1,478	41	7.93	5
1964	1,895.48	1,548	1,829	67	8.24	8
1965	611.14	495	585	26	8.56	3
1966	1,500.19	1,204	1,422	78	8.88	9
1967	7,810.50	6,212	7,339	472	9.21	51
1968	5,156.86	4,064	4,801	356	9.54	37
1969	2,743.23	2,140	2,528	215	9.89	22
1970	1,104.82	853	1,008	97	10.24	9
1971	31,924.90	24,398	28,823	3,102	10.61	292
1972	2,029.09	1,534	1,812	217	10.98	20
1973	5,741.28	4,292	5,070	671	11.36	59
1974	677.56	500	591	87	11.76	7
1975	501.75	366	432	69	12.16	6
1976	3,733.18	2,690	3,178	555	12.57	44
1977	1,421.54	1,011	1,194	227	13.00	17
1978	182.88	128	151	32	13.44	2
1979	5,235.99	3,620	4,277	959	13.89	69
1980	17,091.10	11,641	13,752	3,339	14.35	233
1981	121,509.06	81,492	96,272	25,237	14.82	1,703
1982	95,200.74	72,467	85,610	9,590	13.57	707
1983	6,768.10	5,090	6,013	755	13.93	54
1984	6,649.28	4,910	5,801	849	14.61	58
1985	25,257.56	18,400	21,737	3,520	15.00	235
1986	23,743.92	17,055	20,148	3,596	15.39	234
1987	25,830.88	18,278	21,593	4,238	15.81	268
1988	26,270.40	18,300	21,619	4,651	16.22	287
1989	52,802.47	36,175	42,736	10,066	16.66	604
1990	55,497.04	37,366	44,143	11,354	17.10	664
1991	30,826.21	20,376	24,072	6,755	17.56	385
1992	56,752.96	36,799	43,473	13,280	18.03	737
1993	45,455.69	28,878	34,116	11,340	18.51	613
1994	30,338.27	18,867	22,289	8,049	19.00	424

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1995	22,678.63	13,789	16,290	6,389	19.50	328
1996	22,335.06	13,263	15,669	6,667	20.01	333
1997	8,544.26	4,948	5,845	2,699	20.53	131
1998	8,784.27	4,979	5,882	2,902	20.83	139
1999	13,041.26	7,188	8,492	4,550	21.37	213
2000	2,551.99	1,366	1,614	938	21.92	43
2004	347.18	164	194	153	23.79	6
2005	3,317.00	1,505	1,778	1,539	24.39	63
2006	3,670.43	1,604	1,895	1,776	24.80	72
2010	54.74	20	24	31	26.52	1
2012	115,202.00	38,109	45,021	70,181	27.31	2,570
2013	22,348.33	6,928	8,185	14,164	27.82	509
2014	10,178.04	2,950	3,485	6,693	28.18	238
2015	1,657.77	447	528	1,130	28.41	40
2017	320.08	72	85	235	29.09	8
2018	4,740.95	967	1,142	3,599	29.26	123
2019	1,261.22	228	269	992	29.47	34
2024	29,317.59	1,489	1,759	27,559	28.00	984
	982,535.45	598,019	706,337	276,198		13,716

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.1 1.40

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	280	291			
1990	10,556.06	10,084	10,556			
1991	4,510.10	4,279	4,510			
1992	3,050.56	2,871	3,051			
1993	5,858.48	5,460	5,858			
1994	335.37	309	335			
1997	104.02	93	119		15-	
	24,705.16	23,376	24,720		15-	

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,366	1,369			
1952	1,125.65	1,117	1,126			
1953	30,125.92	29,734	30,126			
1954	5,517.65	5,410	5,518			
1955	601.79	586	602			
1956	8,337.58	8,065	8,338			
1957	1,905.18	1,830	1,905			
1958	651.12	621	651			
1959	15,785.61	14,945	15,786			
1960	2,005.39	1,886	2,005			
1961	1,960.14	1,831	1,960			
1962	288.11	267	288			
1963	1,039.65	959	1,040			
1964	5,769.25	5,292	5,769			
1965	1,751.72	1,597	1,752			
1966	3,912.12	3,545	3,912			
1967	4,863.78	4,381	4,864			
1968	8,062.42	7,216	8,062			
1969	1,581.42	1,407	1,581			
1970	2,285.43	2,019	2,285			
1971	10,974.98	9,633	10,975			
1972	4,046.99	3,527	4,047			
1974	1,652.12	1,419	1,652			
1975	8,480.27	7,227	8,480			
1976	7,949.17	6,719	7,949			
1977	2,458.86	2,061	2,459			
1978	1,265.56	1,051	1,266			
1979	752.79	619	753			
1980	1,718.37	1,399	1,718			
1981	10,162.67	8,181	10,163			
1982	12,027.61	10,248	12,028			
1983	1,755.64	1,476	1,756			
1984	30,831.09	25,688	30,831			
1985	13,068.42	10,783	13,068			
1986	19,569.87	15,901	19,570			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1987	23,586.65	18,945	23,587			
1988	13,276.05	10,484	13,276			
1989	15,968.66	12,446	15,888	81	10.26	8
1990	33,323.13	25,489	32,537	786	10.83	73
1991	26,014.16	19,513	24,909	1,105	11.41	97
1992	15,045.39	11,107	14,178	867	11.79	74
1993	23,968.53	17,315	22,103	1,865	12.39	151
1994	51,100.60	36,251	46,275	4,825	12.80	377
1995	69,990.02	48,482	61,889	8,101	13.42	604
1996	45,414.72	30,687	39,173	6,242	14.04	445
1997	84,495.34	55,851	71,295	13,200	14.49	911
1998	75,399.07	48,489	61,897	13,502	15.12	893
1999	119,656.29	74,761	95,434	24,222	15.76	1,537
2000	199,968.82	121,681	155,329	44,640	16.24	2,749
2001	116,038.59	68,382	87,291	28,747	16.90	1,701
2002	42,457.03	24,184	30,871	11,586	17.57	659
2003	222,013.40	122,507	156,383	65,630	18.07	3,632
2004	109,705.10	58,275	74,390	35,316	18.75	1,884
2005	70,405.76	35,928	45,863	24,543	19.43	1,263
2006	85,043.37	41,748	53,292	31,751	19.96	1,591
2007	37,304.93	17,496	22,334	14,971	20.66	725
2008	97,908.80	44,372	56,642	41,267	21.11	1,955
2009	42,499.78	18,300	23,360	19,139	21.82	877
2011	14,980.73	5,778	7,376	7,605	23.09	329
2013	30,446.98	10,315	13,167	17,280	24.40	708
2018	12,429.20	2,657	3,392	9,037	27.59	328
2019	31,358.25	5,870	7,493	23,865	28.22	846
2020	191,812.76	30,690	39,177	152,636	28.87	5,287
2022	92,398.23	9,702	12,385	80,013	29.83	2,682
2023	200,050.99	15,244	19,459	180,592	30.29	5,962
2024	76,548.71	3,605	4,602	71,947	30.35	2,371
2025	66,450.74	1,103	1,408	65,043	29.53	2,203
	2,602,976.26	1,287,925	1,602,572	1,000,404		42,922
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	428	461			
1976	21,500.00	18,173	21,500			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1984	1,544.96	1,287	1,545			
1987	5,496.89	4,415	5,497			
1988	2,425.60	1,915	2,426			
1997	821.60	543	802	20	14.49	1
2008	85,066.24	38,552	56,926	28,140	21.11	1,333
	117,316.10	65,313	89,156	28,160		1,334
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1914	0.25		0			
1919	46.40	46	46			
1920	65.00	65	65			
1924	288.57	289	289			
1926	8.25	8	8			
1927	265.80	266	266			
1928	32.00	32	32			
1929	401.84	402	402			
1930	576.33	576	576			
1931	862.24	862	862			
1932	179.53	180	180			
1935	339.96	340	340			
1936	180.10	180	180			
1937	702.11	702	702			
1938	70.20	70	70			
1939	114.20	114	114			
1941	93.19	93	93			
1946	107.86	108	108			
1947	228.20	228	228			
1950	115.54	116	116			
1951	399.62	399	400			
1953	526.32	519	526			
1954	866.71	850	867			
1955	3,485.13	3,395	3,485			
1956	166.98	162	167			
1957	807.41	776	807			
1958	3,980.48	3,795	3,980			
1959	3,557.12	3,368	3,557			
1960	940.90	885	941			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
1961	2,160.12	2,018	2,160			
1962	2,440.64	2,266	2,441			
1963	1,463.53	1,350	1,464			
1964	852.14	782	852			
1965	4,391.44	4,004	4,391			
1966	7,725.03	7,001	7,725			
1967	9,375.01	8,445	9,375			
1968	1,802.13	1,613	1,802			
1969	4,312.49	3,836	4,312			
1970	727.19	642	727			
1971	12,970.95	11,385	12,971			
1972	4,161.73	3,627	4,162			
1973	5,521.13	4,777	5,521			
1974	4,072.92	3,499	4,073			
1975	1,691.94	1,442	1,685	7	5.91	1
1976	2,859.26	2,417	2,825	34	6.19	5
1977	9,079.27	7,608	8,892	188	6.48	29
1978	8,076.46	6,708	7,840	237	6.78	35
1979	16,025.59	13,181	15,405	621	7.10	87
1980	16,463.34	13,401	15,662	801	7.44	108
1981	18,913.59	15,225	17,794	1,120	7.80	144
1982	17,303.36	14,742	17,229	74	7.51	10
1983	24,489.09	20,590	24,064	425	8.00	53
1984	30,607.35	25,502	29,805	803	8.26	97
1985	47,810.95	39,449	46,105	1,706	8.53	200
1986	41,095.26	33,390	39,024	2,072	9.06	229
1987	31,108.85	24,987	29,203	1,906	9.37	203
1988	67,276.33	53,128	62,092	5,185	9.92	523
1989	73,855.80	57,563	67,275	6,581	10.26	641
1990	72,040.64	55,104	64,401	7,639	10.83	705
1991	46,648.02	34,991	40,895	5,753	11.41	504
1992	72,629.85	53,615	62,661	9,969	11.79	846
1993	50,628.58	36,574	42,745	7,884	12.39	636
1994	79,302.27	56,257	65,749	13,554	12.80	1,059
1995	207,257.72	143,567	167,790	39,468	13.42	2,941
1996	83,557.81	56,460	65,986	17,572	14.04	1,252
1997	20,844.66	13,778	16,103	4,742	14.49	327
1998	283,838.00	182,536	213,334	70,504	15.12	4,663
1999	62,321.83	38,939	45,509	16,813	15.76	1,067
2000	24,248.93	14,755	17,244	7,004	16.24	431
2006	20,518.49	10,073	11,773	8,746	19.96	438

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 40-R2.5						
NET SALVAGE PERCENT.. 0						
2010	4,783.98	1,958	2,288	2,496	22.38	112
2014	897.06	283	331	566	25.00	23
2016	116,605.62	30,900	36,113	80,492	26.34	3,056
2017	219,792.43	52,684	61,573	158,220	26.96	5,869
2018	159,592.89	34,121	39,878	119,715	27.59	4,339
2019	186,196.01	34,856	40,737	145,459	28.22	5,154
2020	386,652.62	61,864	72,302	314,351	28.87	10,889
2022	1,515.12	159	186	1,329	29.83	45
	2,587,913.66	1,316,878	1,533,879	1,054,034		46,721
	5,308,206.02	2,670,116	3,225,608	2,082,598		90,977
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					22.9	1.71

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,727	10,727			
2001	13,978.74	13,559	13,859	120	0.75	120
2002	7,564.41	7,035	7,191	374	1.75	214
2003	93,599.07	83,303	85,146	8,453	2.75	3,074
	1,490,664.11	1,479,419	1,481,718	8,946		3,408

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.6 0.23

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1905	1,382.43	1,175	1,097	286	13.35	21
1906	292.55	248	231	61	13.47	5
1907	1,480.00	1,254	1,170	310	13.60	23
1909	419.56	354	330	89	13.84	6
1910	231.57	195	182	50	13.96	4
1911	21.85	18	17	5	14.08	
1912	1,782.05	1,496	1,396	386	14.20	27
1914	166.16	139	130	36	14.43	2
1915	20.13	17	16	4	14.54	
1918	7,489.42	6,217	5,803	1,687	14.88	113
1920	2,849.28	2,356	2,199	650	15.10	43
1921	435.07	359	335	100	15.21	7
1922	6,291.36	5,182	4,837	1,455	15.32	95
1923	1,971.44	1,621	1,513	458	15.42	30
1924	4,604.09	3,777	3,525	1,079	15.53	69
1926	3,813.02	3,115	2,908	905	15.74	57
1931	32,017.60	25,880	24,156	7,861	16.24	484
1938	400.93	319	298	103	16.90	6
1943	284.29	223	208	76	17.32	4
1944	230.75	181	169	62	17.41	4
1945	237.24	185	173	65	17.48	4
1949	486.95	376	351	136	17.79	8
1950	50,769.67	39,079	36,476	14,294	17.86	800
1951	16,250.78	12,471	11,640	4,610	17.93	257
1952	20,545.14	15,717	14,670	5,875	18.00	326
1953	22,260.06	16,974	15,843	6,417	18.07	355
1954	302,640.23	230,043	214,721	87,919	18.13	4,849
1955	1,162.29	880	821	341	18.20	19
1956	1,010.54	763	712	298	18.26	16
1957	3,926.06	2,954	2,757	1,169	18.32	64
1958	1,997.30	1,497	1,397	600	18.38	33
1959	2,678.45	2,001	1,868	811	18.44	44
1960	5,791.48	4,310	4,023	1,769	18.50	96
1961	18,138.80	13,446	12,550	5,588	18.56	301
1962	12,971.47	9,579	8,941	4,030	18.61	217
1963	9,060.40	6,663	6,219	2,841	18.67	152
1964	11,494.93	8,419	7,858	3,637	18.72	194
1965	5,910.61	4,311	4,024	1,887	18.77	101
1966	358.24	260	243	116	18.82	6
1967	496.96	359	335	162	18.87	9

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1968	1,817.74	1,308	1,221	597	18.91	32
1969	7,616.15	5,454	5,091	2,525	18.96	133
1970	3,024.29	2,155	2,011	1,013	19.01	53
1971	1,477.38	1,048	978	499	19.05	26
1972	596.71	421	393	204	19.09	11
1973	3,204.98	2,249	2,099	1,106	19.13	58
1978	1,708.01	1,163	1,086	622	19.32	32
1980	6,221.53	4,181	3,903	2,319	19.39	120
1983	15,322.42	10,553	9,850	5,472	19.10	286
1985	12,630.08	8,540	7,971	4,659	19.27	242
1988	52,754.56	34,781	32,464	20,290	19.25	1,054
1989	8,424.15	5,497	5,131	3,293	19.31	171
1990	123,521.99	79,684	74,377	49,145	19.39	2,535
1992	47,851.27	30,232	28,218	19,633	19.38	1,013
1994	1,725,445.56	1,062,184	991,437	734,008	19.51	37,622
1995	22,173.60	13,482	12,584	9,590	19.50	492
1996	2,259.68	1,355	1,265	995	19.53	51
1998	25,800.00	15,047	14,045	11,755	19.48	603
2000	8,328.00	4,689	4,377	3,951	19.59	202
2001	24,091.65	13,320	12,433	11,659	19.61	595
2002	46,954.16	25,435	23,741	23,213	19.67	1,180
2003	136,654.40	72,673	67,833	68,822	19.59	3,513
2004	72,983.68	37,995	35,464	37,519	19.57	1,917
2005	59,996.43	30,496	28,465	31,532	19.59	1,610
2012	74,314.34	30,298	28,280	46,034	19.61	2,347
2014	123,382.06	45,553	42,519	80,863	19.65	4,115
2015	9,379.40	3,270	3,052	6,327	19.62	322
2016	80,514.53	26,232	24,485	56,030	19.66	2,850
2018	20,625.68	5,709	5,329	15,297	19.60	780
2021	3,917.00	737	688	3,229	19.42	166
2022	85,956.98	13,177	12,299	73,658	19.33	3,811
2023	1,259,400.03	145,083	135,420	1,123,980	19.19	58,571
2024	351,767.53	25,820	24,100	327,667	18.95	17,291
2025	106,566.22	2,845	2,656	103,911	18.23	5,700
	5,081,053.34	2,187,079	2,041,409	3,039,644		158,355

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1950	670.03	641	598	72	2.94	24
1951	822.27	786	734	89	2.95	30
1955	801,398.39	764,622	713,695	87,704	2.95	29,730
1956	1,047.45	999	932	115	2.95	39
1957	10,249.83	9,769	9,118	1,131	2.95	383
1958	2,482.66	2,365	2,207	275	2.96	93
1959	5,183.81	4,934	4,605	578	2.96	195
1960	4,948.06	4,707	4,393	555	2.96	188
1961	539,405.64	512,813	478,657	60,748	2.96	20,523
1962	339.03	322	301	38	2.96	13
1963	277.93	264	246	32	2.96	11
1966	3,859.88	3,657	3,413	446	2.96	151
1967	2,790.92	2,642	2,466	325	2.96	110
1969	866.59	819	764	102	2.97	34
1970	8,032.58	7,584	7,079	954	2.97	321
1971	18,401.44	17,359	16,203	2,199	2.97	740
1972	3,388.32	3,193	2,980	408	2.97	137
1973	2,861.11	2,694	2,515	347	2.97	117
1974	1,212,931.09	1,140,895	1,064,906	148,025	2.97	49,840
1975	22,751.74	21,378	19,954	2,798	2.97	942
1976	32,788.40	30,776	28,726	4,062	2.97	1,368
1977	35,227.17	33,027	30,827	4,400	2.97	1,481
1978	14,269.12	13,362	12,472	1,797	2.97	605
1979	148,221.56	138,627	129,394	18,828	2.97	6,339
1980	460,230.72	429,883	401,251	58,980	2.97	19,859
1981	57,414.00	53,543	49,977	7,437	2.98	2,496
1982	38,599.74	36,060	33,658	4,942	3.05	1,620
1983	2,914.84	2,722	2,541	374	3.00	125
1984	89,751.74	83,667	78,094	11,657	3.00	3,886
1985	30,648.24	28,497	26,599	4,049	3.04	1,332
1986	140,082.48	130,305	121,626	18,456	2.95	6,256
1987	3,330.36	3,096	2,890	441	2.90	152
1988	2,092.34	1,941	1,812	281	2.91	97
1989	964,184.71	891,292	831,928	132,257	2.96	44,681
1990	710,334.35	656,065	612,368	97,966	2.92	33,550
1991	55,324.88	50,971	47,576	7,749	2.93	2,645
1992	345,020.86	316,626	295,537	49,484	2.98	16,605
1993	37,015.00	33,902	31,644	5,371	2.96	1,815
1994	335,991.96	306,593	286,172	49,819	3.00	16,606
1995	34,567.26	31,473	29,377	5,191	2.97	1,748

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2028						
NET SALVAGE PERCENT.. 0						
1996	43,356.00	39,315	36,696	6,660	3.01	2,213
1997	10,221.04	9,240	8,625	1,596	3.00	532
1998	247,914.36	223,619	208,725	39,189	2.96	13,240
2000	1,459,320.19	1,304,340	1,217,465	241,855	3.00	80,618
2001	376,052.25	334,687	312,395	63,657	3.00	21,219
2002	173,687.14	153,852	143,605	30,082	3.00	10,027
2003	200,366.76	176,543	164,784	35,582	3.00	11,861
2004	200,396.72	175,868	164,154	36,242	2.96	12,244
2005	508,142.12	442,490	413,018	95,124	3.00	31,708
2006	72,718.65	62,989	58,794	13,925	2.97	4,689
2007	745,744.60	641,042	598,346	147,399	2.98	49,463
2008	547,767.46	467,793	436,636	111,132	2.99	37,168
2009	132,314.80	111,991	104,532	27,783	2.99	9,292
2010	92,229.97	77,344	72,193	20,037	2.98	6,724
2011	75,088.53	62,278	58,130	16,959	2.98	5,691
2012	249,484.70	204,428	190,812	58,673	2.98	19,689
2013	35,996.21	29,067	27,131	8,865	2.98	2,975
2014	291,133.76	231,015	215,628	75,505	2.99	25,253
2015	382,922.06	297,913	278,071	104,851	3.00	34,950
2016	809,233.07	615,826	574,809	234,424	2.98	78,666
2017	172,226.42	127,516	119,023	53,204	2.98	17,854
2018	1,012,875.83	724,713	676,444	336,432	2.98	112,897
2019	2,122,560.22	1,454,166	1,357,312	765,249	2.99	255,936
2020	9,687.78	6,277	5,859	3,829	2.99	1,281
2021	237,483.72	142,775	133,266	104,218	2.99	34,856
2022	1,978,885.35	1,068,004	996,870	982,015	2.99	328,433
2023	1,263,784.01	576,286	537,903	725,881	2.98	243,584
2024	484,176.90	162,102	151,305	332,872	2.98	111,702
2025	3,073,384.44	443,182	413,664	2,659,720	2.97	895,529
	23,189,873.56	16,141,532	15,066,430	8,123,444		2,727,181
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
1969	6,798.01	3,670	3,426	3,372	37.59	90
1970	3,383.06	1,808	1,688	1,695	37.85	45
1989	25,957.50	12,514	11,681	14,277	38.94	367

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2075						
NET SALVAGE PERCENT.. 0						
1992	58,567.66	26,871	25,081	33,486	39.22	854
1994	10,549.87	4,648	4,338	6,211	39.67	157
2002	4,127.48	1,507	1,407	2,721	40.45	67
2005	2,644.58	884	825	1,819	40.36	45
2010	2,788.23	769	718	2,070	40.68	51
2011	36,615.99	9,608	8,968	27,648	40.75	678
2014	167,443.92	36,972	34,509	132,934	40.58	3,276
2015	204,441.65	42,074	39,272	165,170	40.52	4,076
2016	539,847.11	102,571	95,739	444,108	40.50	10,966
2018	842,885.66	132,164	123,361	719,524	40.34	17,836
2019	4,975.51	696	650	4,326	40.01	108
2021	103,857.62	10,614	9,907	93,951	39.55	2,375
2022	24,312.57	1,998	1,865	22,448	39.06	575
2023	14,599,888.58	893,513	834,001	13,765,888	38.32	359,235
2024	12,255,071.05	474,271	442,682	11,812,389	37.26	317,026
2025	1,920,001.92	27,648	25,807	1,894,195	34.34	55,160
	30,814,157.97	1,784,800	1,665,924	29,148,234		772,987
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1933	657.93	547	511	147	13.94	11
1992	1,969,044.37	1,329,105	1,240,580	728,464	16.01	45,501
1993	15,226.14	10,165	9,488	5,738	16.06	357
1994	10,056.65	6,663	6,219	3,837	15.92	241
2000	1,880.00	1,149	1,072	808	16.07	50
2001	34,203.52	20,570	19,200	15,004	16.07	934
2021	22,887.76	5,035	4,700	18,188	15.95	1,140
2022	3,729.30	672	627	3,102	15.92	195
2023	23,764.21	3,244	3,028	20,736	15.82	1,311
2024	18,478.82	1,615	1,507	16,971	15.65	1,084
2025	79,939.97	2,558	2,388	77,552	15.15	5,119
	2,179,868.67	1,381,323	1,289,320	890,549		55,943

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2009	4,797,873.14	1,694,129	1,581,292	3,216,581	30.23	106,404
2011	174,377.96	56,638	52,866	121,512	30.14	4,032
2021	84,360.17	11,119	10,378	73,982	29.63	2,497
2022	1,292,527.36	137,525	128,365	1,164,162	29.39	39,611
2023	118,404.34	9,378	8,753	109,651	29.05	3,775
2024	87,895.68	4,412	4,118	83,778	28.35	2,955
2025	116,849.61	2,150	2,007	114,843	26.67	4,306
	6,672,288.26	1,915,351	1,787,780	4,884,508		163,580
UGI-GAS - GAS TRAINING CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2021	31,183,853.56	3,339,791	3,117,345	28,066,509	37.52	748,041
2022	3,002,042.24	258,476	241,260	2,760,782	37.15	74,314
2023	29,706.91	1,901	1,774	27,933	36.56	764
2024	21,138.08	856	799	20,339	35.54	572
2025	30,709.16	461	430	30,279	32.83	922
	34,267,449.95	3,601,485	3,361,609	30,905,841		824,613
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			
1938	143.77	144	144			
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	401	401			
1949	1,806.43	1,806	1,806			
1950	2,196.55	2,197	2,197			
1951	233.36	233	233			
1953	27,799.96	27,439	25,505	2,294	0.52	2,294
1954	20,454.90	20,056	18,643	1,812	0.78	1,812
1955	3,292.27	3,207	2,981	311	1.04	299
1957	1,355.54	1,302	1,210	145	1.58	92
1958	5,763.15	5,495	5,108	655	1.86	352
1959	1,958.52	1,854	1,723	235	2.14	110
1960	3,574.90	3,359	3,122	453	2.42	187
1961	649.28	605	562	87	2.70	32
1962	9,412.34	8,709	8,095	1,317	2.99	440
1963	12,936.88	11,876	11,039	1,898	3.28	579
1964	3,052.55	2,780	2,584	468	3.57	131
1966	2,516.15	2,255	2,096	420	4.15	101
1967	1,274.89	1,133	1,053	222	4.45	50
1968	419.83	370	344	76	4.74	16
1970	731.03	633	588	143	5.34	27
1971	10,643.95	9,143	8,499	2,145	5.64	380
1972	1,090.13	928	863	228	5.95	38
1975	164.27	136	126	38	6.93	5
1976	24,200.07	19,802	18,407	5,793	7.27	797
1977	7,165.00	5,798	5,389	1,776	7.63	233
1978	8,046.84	6,437	5,983	2,063	8.00	258
1979	4,081.97	3,227	3,000	1,082	8.38	129
1980	13,629.88	10,642	9,892	3,738	8.77	426
1983	369.74	303	282	88	9.30	9
1985	27,096.76	21,705	20,176	6,921	10.00	692
1986	5,526.05	4,381	4,072	1,454	10.26	142
1988	338.67	260	242	97	11.29	9
1989	19,959.70	15,121	14,055	5,904	11.60	509
1990	1,194.94	889	826	369	12.14	30
1991	5,163.03	3,785	3,518	1,645	12.48	132

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1992	7,676.31	5,513	5,125	2,552	13.05	196
1994	38,494.90	26,585	24,712	13,783	14.00	984
1995	28,542.82	19,341	17,978	10,565	14.39	734
1997	46,847.50	30,306	28,170	18,677	15.42	1,211
1998	39,421.11	24,816	23,067	16,354	16.04	1,020
1999	72,667.26	44,632	41,487	31,180	16.49	1,891
2000	38,962.96	23,218	21,582	17,381	17.12	1,015
2001	110,913.42	64,285	59,755	51,158	17.59	2,908
2002	39,331.76	22,038	20,485	18,847	18.24	1,033
2003	35,150.00	19,083	17,738	17,412	18.73	930
2004	52,683.27	27,653	25,704	26,979	19.23	1,403
2005	302,659.69	153,206	142,410	160,249	19.75	8,114
2006	139,043.00	67,450	62,697	76,346	20.43	3,737
2007	78,002.02	36,302	33,744	44,258	20.96	2,112
2011	148,951.37	57,451	53,403	95,549	23.09	4,138
2012	1,935.54	706	656	1,279	23.54	54
2013	5,265.73	1,797	1,670	3,595	24.13	149
2014	187,584.86	59,539	55,344	132,241	24.73	5,347
2015	20,002.66	5,881	5,467	14,536	25.21	577
2016	52,555.80	14,180	13,181	39,375	25.71	1,532
2017	28,421.86	6,958	6,468	21,954	26.22	837
2018	276,078.65	60,461	56,201	219,878	26.75	8,220
2019	737,164.05	142,273	132,248	604,916	27.17	22,264
2020	469,675.04	78,013	72,516	397,159	27.61	14,385
2021	305,923.54	42,401	39,413	266,510	27.97	9,528
2022	4,000.00	442	411	3,589	28.15	127
2023	4,502.00	366	340	4,162	28.27	147
2024	174,756.78	8,878	8,252	166,504	28.00	5,947
2025	11,517.54	214	199	11,319	26.45	428
	3,754,319.25	1,309,341	1,222,133	2,532,186		111,279
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	100,930.51	73,839	89,620	11,311	19.64	576
1961	86,871.16	63,287	76,813	10,058	19.71	510
1962	141,136.69	102,399	124,284	16,853	19.77	852
1963	9,480.45	6,849	8,313	1,168	19.83	59

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1964	3,689.12	2,654	3,221	468	19.89	24
1965	479.00	343	416	63	19.95	3
1966	297.39	212	257	40	20.01	2
1967	860.37	610	740	120	20.07	6
1968	3,570.31	2,520	3,059	512	20.12	25
1969	661.27	464	563	98	20.17	5
1970	2,325.05	1,624	1,971	354	20.23	17
1971	74,835.43	51,999	63,112	11,723	20.28	578
1972	5,279.41	3,648	4,428	852	20.33	42
1973	5,863.34	4,030	4,891	972	20.37	48
1974	1,077.54	736	893	184	20.42	9
1975	20,112.15	13,656	16,575	3,538	20.47	173
1976	98,397.02	66,404	80,596	17,801	20.51	868
1977	262,518.62	176,021	213,640	48,878	20.55	2,378
1978	14,862.88	9,901	12,017	2,846	20.59	138
1979	31,316.64	20,717	25,145	6,172	20.63	299
1980	50,253.77	33,008	40,062	10,191	20.67	493
1981	48,963.34	31,921	38,743	10,220	20.71	493
1982	16,098.09	10,931	13,267	2,831	20.45	138
1983	15,919.21	10,761	13,061	2,858	20.25	141
1984	47,604.50	31,809	38,607	8,997	20.48	439
1985	68,749.88	45,657	55,415	13,335	20.36	655
1986	220,372.23	144,454	175,327	45,045	20.63	2,183
1987	95,726.84	62,242	75,544	20,182	20.58	981
1988	78,940.78	50,869	61,741	17,200	20.55	837
1989	133,833.58	85,386	103,635	30,199	20.57	1,468
1990	1,474.46	930	1,129	346	20.61	17
1991	12,756.63	7,952	9,652	3,105	20.69	150
1992	108,291.24	66,610	80,846	27,445	20.81	1,319
1993	238,990.24	145,665	176,797	62,194	20.66	3,010
1994	9,228.65	5,537	6,720	2,508	20.83	120
1995	133,112.29	78,922	95,789	37,323	20.77	1,797
1996	77,622.54	45,409	55,114	22,509	20.75	1,085
1997	4,624,824.64	2,665,286	3,234,912	1,389,912	20.77	66,919
1998	280,621.46	159,056	193,050	87,572	20.83	4,204
1999	84,872.92	47,232	57,326	27,546	20.92	1,317
2000	89,743.66	49,171	59,680	30,064	20.83	1,443
2001	725,398.24	390,554	474,023	251,375	20.79	12,091
2002	42,268.05	22,309	27,077	15,191	20.80	730
2003	180,782.36	93,320	113,264	67,518	20.85	3,238

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2004	146,160.24	73,606	89,337	56,823	20.95	2,712
2005	167,022.30	82,192	99,758	67,264	20.90	3,218
2006	140,015.92	67,110	81,453	58,563	20.91	2,801
2007	877,150.17	408,226	495,472	381,678	20.96	18,210
2008	79,300.50	36,082	43,793	35,507	20.96	1,694
2009	54,131.55	23,850	28,947	25,184	20.95	1,202
2010	196,247.48	83,346	101,159	95,089	21.00	4,528
2011	314,990.40	128,800	156,327	158,663	20.96	7,570
2012	49,422.81	19,349	23,484	25,939	20.98	1,236
2013	122,684.15	45,859	55,660	67,024	20.94	3,201
2014	163,988.66	58,085	70,499	93,490	20.97	4,458
2015	94,908.17	31,690	38,463	56,445	20.95	2,694
2016	608,702.23	190,280	230,947	377,755	20.89	18,083
2017	14,886.51	4,302	5,221	9,665	20.91	462
2025	4,028.00	102	124	3,904	19.30	202
	11,284,653.04	6,139,783	7,451,981	3,832,672		184,151
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	24,648	27,375			
1961	2,250.14	2,024	2,250			
1962	11,395.40	10,233	11,395			
1964	212.41	190	212			
1965	479.69	429	480			
1972	4,846.95	4,281	4,847			
1973	59,338.04	52,297	59,338			
1976	674.99	591	675			
1977	9,114.69	7,963	9,115			
1978	24,124.85	21,026	24,125			
1979	540.75	470	541			
1980	8,726.53	7,566	8,727			
1981	52,430.77	45,335	52,431			
1982	22,292.87	19,475	22,293			
1984	11,417.15	9,890	11,417			
1986	31,130.64	26,760	31,131			
1987	11,362.33	9,735	11,362			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2032						
NET SALVAGE PERCENT.. 0						
1988	15,773.37	13,455	15,773			
1989	8,654.63	7,373	8,655			
1990	94,337.02	79,809	94,337			
1992	6,049.58	5,069	6,050			
1993	1,598.34	1,335	1,598			
1994	38,859.45	32,300	38,859			
1995	4,586.75	3,788	4,587			
1996	1,532.27	1,255	1,532			
1997	1,129.92	922	1,130			
1998	3,483.10	2,819	3,483			
2001	6,551.41	5,180	6,468	83	6.42	13
2002	8,685.69	6,805	8,497	189	6.42	29
2003	26,975.97	20,947	26,155	821	6.40	128
2004	262,708.52	201,524	251,630	11,078	6.45	1,718
2005	28,203.02	21,417	26,742	1,461	6.42	228
2008	29,302.79	21,435	26,765	2,538	6.42	395
2010	189,349.18	133,832	167,107	22,242	6.43	3,459
2011	217,404.63	150,683	188,148	29,256	6.42	4,557
2014	19,697.18	12,640	15,783	3,914	6.42	610
2016	36,430.01	21,734	27,138	9,292	6.42	1,447
2020	4,772.90	2,202	2,749	2,023	6.42	315
	1,283,798.91	989,437	1,200,900	82,899		12,899
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2001	6,628.41	3,263	3,960	2,668	25.01	107
2002	3,783,335.80	1,820,920	2,210,088	1,573,248	25.06	62,779
2003	87,794.37	41,219	50,028	37,766	25.14	1,502
2004	116,222.01	53,346	64,747	51,475	25.05	2,055
2005	21,321.99	9,542	11,581	9,741	25.00	390
2006	70,501.63	30,534	37,060	33,442	25.20	1,327
2007	23,909.23	10,080	12,234	11,675	25.04	466
2008	36,082.96	14,837	18,008	18,075	25.06	721
2009	2,440.34	966	1,172	1,268	25.17	50
2010	44,187.56	16,849	20,450	23,738	25.15	944
2011	22,823.04	8,340	10,122	12,701	25.18	504

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2012	5,700.89	1,993	2,419	3,282	25.11	131
2013	10,921.02	3,631	4,407	6,514	25.09	260
2014	82,583.84	25,931	31,473	51,111	25.13	2,034
2015	2,300.95	679	824	1,477	25.09	59
2016	41,558.96	11,412	13,851	27,708	25.10	1,104
2021	94,830.25	14,594	17,713	77,117	24.74	3,117
2022	973,757.93	121,330	147,261	826,497	24.59	33,611
2023	81,823.98	7,626	9,256	72,568	24.31	2,985
2024	301,308.21	17,777	21,576	279,732	23.94	11,685
2025	136,691.16	2,953	3,584	133,107	22.70	5,864
	5,946,724.53	2,217,822	2,691,816	3,254,909		131,695
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
2014	780,161.32	213,530	259,166	520,996	30.52	17,071
2015	32,204.52	8,251	10,014	22,190	30.48	728
2016	12,899.16	3,064	3,719	9,180	30.50	301
2022	25,185.45	2,655	3,222	21,963	29.72	739
2023	69,633.76	5,466	6,634	63,000	29.35	2,147
2025	6,818.51	124	151	6,668	26.97	247
	926,902.72	233,090	282,906	643,997		21,233
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	280,331.31	240,805	280,331			
1972	819.18	697	819			
1973	1,448.41	1,221	1,448			
1974	13,842.50	11,562	13,843			
1975	146,776.04	121,347	146,776			
1976	284,409.36	232,718	283,601	808	7.27	111
1978	1,790.28	1,432	1,745	45	8.00	6
1983	1,783.82	1,462	1,782	2	9.30	

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1984	8,520.87	6,924	8,438	83	9.51	9
1986	1,514.84	1,201	1,464	51	10.26	5
1987	65,137.00	50,826	61,939	3,198	10.77	297
1988	169,541.45	130,106	158,553	10,988	11.29	973
1989	18,663.17	14,139	17,230	1,433	11.60	124
1990	3,349.53	2,491	3,036	314	12.14	26
1992	921.16	662	807	114	13.05	9
1994	8,616.93	5,951	7,252	1,365	14.00	98
1995	478.10	324	395	83	14.39	6
1996	2,301.93	1,522	1,855	447	15.00	30
1997	23,460.19	15,176	18,494	4,966	15.42	322
1998	20,910.41	13,163	16,041	4,869	16.04	304
1999	5,025.24	3,087	3,762	1,263	16.49	77
2000	411,880.07	245,439	299,104	112,776	17.12	6,587
2001	15,936.04	9,237	11,257	4,679	17.59	266
2002	132,402.81	74,185	90,405	41,997	18.24	2,302
2003	14,271.77	7,748	9,442	4,830	18.73	258
2004	40,977.09	21,509	26,212	14,765	19.23	768
2005	20,042.49	10,146	12,364	7,678	19.75	389
2007	63,327.92	29,473	35,917	27,411	20.96	1,308
2008	2,287.79	1,029	1,254	1,034	21.41	48
2009	9,297.12	3,988	4,860	4,437	21.96	202
2010	66,442.25	27,082	33,003	33,439	22.52	1,485
2011	414,026.48	159,690	194,606	219,421	23.09	9,503
2012	84,354.10	30,747	37,470	46,884	23.54	1,992
2014	114,343.64	36,293	44,228	70,115	24.73	2,835
2015	184,377.83	54,207	66,059	118,319	25.21	4,693
2016	68,563.53	18,498	22,543	46,021	25.71	1,790
2017	415,243.64	101,652	123,878	291,366	26.22	11,112
2018	670,627.51	146,867	178,979	491,648	26.75	18,379
2019	2,150,850.48	415,114	505,878	1,644,973	27.17	60,544
2020	718,652.38	119,368	145,468	573,185	27.61	20,760
2021	1,700,822.87	235,734	287,277	1,413,546	27.97	50,538
2022	2,090,621.37	231,223	281,779	1,808,842	28.15	64,257
2023	788,535.18	64,029	78,029	710,506	28.27	25,133
2024	859,477.03	43,661	53,207	806,270	28.00	28,795
2025	455,192.92	8,467	10,318	444,875	26.45	16,819
	12,552,196.03	2,952,202	3,583,149	8,969,047		333,160

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1969	2,453.00	2,133	2,453			
1970	872.29	757	872			
1976	342.77	293	343			
1988	1,813.00	1,506	1,813			
1990	11,104.08	9,120	11,069	35	7.67	5
1992	1,829.56	1,490	1,808	21	7.57	3
1993	164,577.50	133,225	161,696	2,881	7.59	380
1994	8,948.74	7,187	8,723	226	7.66	30
1995	553.43	442	536	17	7.63	2
1996	6,824.90	5,410	6,566	259	7.65	34
1997	2,764.61	2,179	2,645	120	7.59	16
1999	58,743.84	45,491	55,213	3,531	7.65	462
2000	1,983.26	1,522	1,847	136	7.64	18
2005	3,338.96	2,427	2,946	393	7.60	52
2006	4,214.76	3,018	3,663	552	7.63	72
2008	49,021.21	34,143	41,440	7,582	7.63	994
2010	2,592.10	1,736	2,107	485	7.65	63
2011	12,791.22	8,383	10,175	2,617	7.62	343
2015	244,901.72	141,700	171,983	72,919	7.65	9,532
2016	106,882.55	59,192	71,842	35,041	7.65	4,581
2017	7,718.68	4,068	4,937	2,781	7.63	364
2018	17,640.50	8,746	10,615	7,025	7.63	921
2021	63,475.20	23,562	28,597	34,878	7.62	4,577
2022	2,400.00	756	918	1,482	7.61	195
2023	7,122.00	1,763	2,140	4,982	7.60	656
2025	3,950.00	248	301	3,649	7.47	488
	788,859.88	500,497	607,248	181,612		23,788
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1989	127.23	89	108	19	15.83	1
1992	758,027.04	511,668	620,802	137,225	16.01	8,571
1993	3,146.41	2,101	2,549	597	16.06	37
1994	8,657.45	5,736	6,959	1,698	15.92	107
1995	2,701.38	1,765	2,141	560	16.05	35
1996	9,933.05	6,421	7,791	2,143	16.00	134

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1998	1,738.51	1,094	1,327	411	16.04	26
2000	420,169.40	256,724	311,481	108,689	16.07	6,763
2002	79,118.01	46,727	56,693	22,425	16.12	1,391
2003	8,394.64	4,875	5,915	2,480	16.07	154
2004	30,839.56	17,563	21,309	9,531	16.06	593
2005	11,025.37	6,140	7,450	3,576	16.11	222
2006	34,349.48	18,714	22,706	11,644	16.08	724
2009	48,535.59	24,588	29,832	18,703	16.07	1,164
2010	16,891.81	8,301	10,072	6,820	16.04	425
2012	6,549.63	2,989	3,627	2,923	16.09	182
2014	117,924.70	49,222	59,721	58,204	16.05	3,626
2015	37,408.06	14,769	17,919	19,489	16.10	1,210
2016	10,340.67	3,841	4,660	5,680	16.08	353
2018	11,932.98	3,804	4,615	7,318	16.03	457
2019	5,810.76	1,677	2,035	3,776	16.02	236
2021	4,225.20	930	1,128	3,097	15.95	194
2022	126,600.86	22,813	27,679	98,922	15.92	6,214
2023	61,685.87	8,420	10,216	51,470	15.82	3,253
2024	53,568.54	4,682	5,681	47,888	15.65	3,060
2025	14,313.88	458	556	13,758	15.15	908
	1,884,016.08	1,026,111	1,244,971	639,045		40,040
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1936	1,234.84	964	1,170	65	18.46	4
1960	294.42	212	257	37	20.76	2
1969	377.45	260	315	62	21.36	3
1975	1,808.65	1,203	1,460	349	21.70	16
1981	26,509.40	16,893	20,496	6,013	21.98	274
1986	357.42	230	279	78	21.73	4
1987	95.00	61	74	21	21.63	1
1988	24.29	15	18	6	21.92	
1989	2,123.00	1,324	1,606	517	21.89	24
1991	4,760.80	2,902	3,521	1,240	21.93	57
1992	2,703.40	1,627	1,974	729	22.00	33
1994	18,973.34	11,147	13,525	5,449	21.94	248

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 90-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1995	4,307.22	2,489	3,020	1,287	22.10	58
1996	9,271.45	5,288	6,416	2,856	22.03	130
1997	11,191.78	6,292	7,634	3,558	22.00	162
1999	519,130.02	282,095	342,263	176,867	22.06	8,018
2000	12,387.00	6,600	8,008	4,379	22.14	198
2002	2,306.86	1,180	1,432	875	22.20	39
2003	6,184.42	3,096	3,756	2,428	22.20	109
2008	184,472.34	81,352	98,704	85,769	22.18	3,867
2014	17,931.59	6,125	7,431	10,500	22.17	474
2017	149,837.36	41,520	50,376	99,461	22.17	4,486
2022	15,322.66	2,118	2,570	12,753	21.82	584
	991,604.71	474,993	576,305	415,300		18,791
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1910	2,631.33	2,631	2,631			
1914	4,425.79	4,426	4,426			
1921	34.95	35	35			
1928	48,718.14	48,718	48,718			
1929	5,726.24	5,726	5,726			
1930	738.76	739	739			
1931	1,329.50	1,330	1,330			
1936	459.65	460	460			
1937	798.45	798	798			
1938	66.22	66	66			
1939	505.95	506	506			
1944	20.08	20	20			
1946	1,700.00	1,700	1,700			
1948	153.57	154	154			
1949	3,419.22	3,419	3,419			
1953	114.00	113	114			
1954	3,369.90	3,304	3,370			
1958	10,313.10	9,834	10,313			
1959	27,782.48	26,296	27,782			
1960	1,594.52	1,498	1,595			
1961	1,314.41	1,226	1,314			
1962	614.41	568	614			

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1963	746.64	685	747			
1964	861.27	784	861			
1965	1,553.29	1,403	1,553			
1966	104,751.07	93,883	104,751			
1967	23,858.73	21,204	23,859			
1968	4,640.61	4,091	4,641			
1969	2,008.79	1,756	2,009			
1970	2,014.32	1,745	2,014			
1971	4,281.55	3,678	4,282			
1972	2,776.85	2,364	2,777			
1973	3,268.03	2,756	3,268			
1974	12,868.29	10,748	12,868			
1976	487.18	399	487			
1977	3,675.13	2,974	3,633	42	7.63	6
1978	423.97	339	414	10	8.00	1
1979	1,309.69	1,035	1,264	45	8.38	5
1980	4,025.99	3,143	3,839	187	8.77	21
1981	4,614.96	3,556	4,344	271	9.18	30
1982	11,408.95	9,474	11,409			
1983	500.00	410	500			
1984	12,832.20	10,427	12,737	95	9.51	10
1985	1,022.46	819	1,000	22	10.00	2
1987	1,781.17	1,390	1,698	83	10.77	8
1988	13,848.31	10,627	12,981	867	11.29	77
1989	1,502.94	1,139	1,391	112	11.60	10
1990	236,214.33	175,696	214,619	21,595	12.14	1,779
1991	44,551.84	32,656	39,890	4,661	12.48	373
1992	18,016.03	12,939	15,805	2,211	13.05	169
1993	112,769.99	79,649	97,294	15,476	13.41	1,154
1994	123,184.01	85,071	103,917	19,267	14.00	1,376
1995	39,025.60	26,444	32,302	6,723	14.39	467
1996	716,749.96	473,772	578,730	138,020	15.00	9,201
1997	241,538.51	156,251	190,866	50,672	15.42	3,286
1998	247,918.65	156,065	190,639	57,280	16.04	3,571
1999	79,405.90	48,771	59,576	19,830	16.49	1,203
2000	174,727.70	104,120	127,186	47,541	17.12	2,777
2001	48,581.99	28,158	34,396	14,186	17.59	806
2002	58,988.30	33,051	40,373	18,615	18.24	1,021
2003	627,003.27	340,400	415,811	211,192	18.73	11,276
2004	750,267.81	393,816	481,060	269,207	19.23	13,999
2005	265,792.85	134,544	164,350	101,443	19.75	5,136

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2006	119,100.02	57,775	70,574	48,526	20.43	2,375
2007	186,501.60	86,798	106,027	80,475	20.96	3,839
2008	816,679.27	367,342	448,721	367,958	21.41	17,186
2009	11,819.05	5,070	6,193	5,626	21.96	256
2010	134,277.17	54,731	66,856	67,421	22.52	2,994
2011	71,427.96	27,550	33,653	37,775	23.09	1,636
2012	72,706.86	26,502	32,373	40,334	23.54	1,713
2013	141,679.13	48,341	59,050	82,629	24.13	3,424
2014	264,648.26	83,999	102,608	162,040	24.73	6,552
2015	294,495.93	86,582	105,763	188,733	25.21	7,486
2016	193,954.73	52,329	63,922	130,033	25.71	5,058
2017	115,906.28	28,374	34,660	81,246	26.22	3,099
2018	290,104.93	63,533	77,608	212,497	26.75	7,944
2019	608,960.07	117,529	143,566	465,394	27.17	17,129
2020	519,803.19	86,339	105,466	414,337	27.61	15,007
2021	743,188.51	103,006	125,826	617,363	27.97	22,072
2022	1,585,043.09	175,306	214,143	1,370,901	28.15	48,700
2023	3,888,868.40	315,776	385,732	3,503,137	28.27	123,917
2024	473,610.79	24,059	29,389	444,222	28.00	15,865
2025	2,737,174.93	50,911	62,190	2,674,985	26.45	101,134
	17,391,579.97	4,447,651	5,396,293	11,995,287		465,150
	159,009,346.87	47,302,497	49,470,173	109,539,174		6,044,845
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					18.1	3.80

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	15,741.19	15,151	12,408	3,333	0.75	3,333
2007	98,862.25	90,212	73,878	24,984	1.75	14,277
2008	10,904.48	9,541	7,813	3,091	2.50	1,236
2009	196,763.79	162,330	132,938	63,826	3.50	18,236
2010	29,674.64	22,998	18,834	10,841	4.50	2,409
2013	49,177.44	30,736	25,171	24,007	7.50	3,201
2014	164,928.32	94,834	77,663	87,265	8.50	10,266
2015	142,233.63	74,673	61,152	81,081	9.50	8,535
2016	156,448.43	74,313	60,858	95,591	10.50	9,104
2017	694,772.06	295,278	241,814	452,958	11.50	39,388
2018	365,293.03	136,985	112,182	253,111	12.50	20,249
2019	260,157.81	84,551	69,242	190,916	13.50	14,142
2020	246,448.03	67,773	55,502	190,946	14.50	13,169
2021	1,078,784.33	242,726	198,777	880,007	15.50	56,775
2022	104,987.55	18,373	15,046	89,941	16.50	5,451
2023	12,578.55	1,572	1,287	11,291	17.50	645
2024	849.08	64	52	797	18.50	43
	3,628,604.61	1,422,110	1,164,617	2,463,988		220,459
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	1,234.22	1,188	1,234			
2007	1,312.22	1,197	1,298	14	1.75	8
2008	24,417.03	21,365	23,165	1,252	2.50	501
2010	2,239.24	1,735	1,881	358	4.50	80
2011	20,678.25	14,992	16,255	4,423	5.50	804
2014	33,759.66	19,412	21,047	12,712	8.50	1,496
2015	35,177.20	18,468	20,024	15,153	9.50	1,595
2016	233,275.70	110,806	120,140	113,135	10.50	10,775
2017	400,100.57	170,043	184,368	215,733	11.50	18,759
2018	31,187.62	11,695	12,680	18,507	12.50	1,481
2019	69,735.23	22,664	24,573	45,162	13.50	3,345
2020	115,739.37	31,828	34,509	81,230	14.50	5,602
2021	147,329.19	33,149	35,942	111,388	15.50	7,186
2022	100,538.69	17,594	19,076	81,463	16.50	4,937

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	16,822.55	2,103	2,280	14,542	17.50	831
2024	4,362.42	327	355	4,008	18.50	217
2025	7,898.56	197	214	7,685	19.50	394
	1,245,807.72	478,763	519,041	726,767		58,011
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	1,393.32	1,341	1,393			
2007	4,828.41	4,406	4,828			
2009	1,926.82	1,590	1,789	138	3.50	39
2013	4,225.61	2,641	2,972	1,254	7.50	167
2014	54,667.08	31,434	35,372	19,295	8.50	2,270
2015	9,361.71	4,915	5,531	3,831	9.50	403
2016	22,950.78	10,902	12,268	10,683	10.50	1,017
2017	31,887.57	13,552	15,250	16,638	11.50	1,447
2018	64,576.87	24,216	27,249	37,327	12.50	2,986
2019	9,728.37	3,162	3,558	6,170	13.50	457
2020	395,875.29	108,866	122,503	273,372	14.50	18,853
2021	6,256.54	1,408	1,584	4,672	15.50	301
2022	279,971.38	48,995	55,132	224,839	16.50	13,627
	887,649.75	257,428	289,430	598,220		41,567
	5,762,062.08	2,158,301	1,973,087	3,788,975		320,037

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8 5.55

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	42,502.55	40,377	41,487	1,015	0.50	1,015
2017	3,747.59	3,185	3,273	475	1.50	317
2020	18,196.00	10,008	10,283	7,913	4.50	1,758
2021	41,085.52	18,488	18,996	22,089	5.50	4,016
	105,531.66	72,058	74,039	31,493		7,106
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	5,541.48	5,264	4,717	825	0.50	825
2017	8,554.22	7,271	6,515	2,039	1.50	1,359
2018	2,800.72	2,101	1,883	918	2.50	367
2019	4,541.15	2,952	2,645	1,896	3.50	542
2021	79,835.69	35,926	32,191	47,644	5.50	8,663
2023	2,910.37	728	652	2,258	7.50	301
	104,183.63	54,242	48,603	55,580		12,057
	209,715.29	126,300	122,642	87,073		19,163

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 9.14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,690.72	18,622	16,896	3,794	0.50	3,794
2022	385,091.78	269,564	244,582	140,509	1.50	93,673
2023	8,449,684.03	4,224,842	3,833,310	4,616,375	2.50	1,846,550
2024	105,727.22	31,718	28,779	76,949	3.50	21,985
2025	2,608,891.49	260,889	236,711	2,372,180	4.50	527,151
	11,570,085.24	4,805,635	4,360,278	7,209,807		2,493,153
PNG						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,690.71	18,622	10,112	10,579	0.50	10,579
	20,690.71	18,622	10,112	10,579		10,579
CPG						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,690.76	18,622	20,691			
	20,690.76	18,622	20,691			
	11,611,466.71	4,842,879	4,391,081	7,220,386		2,503,732

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.9 21.56

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	4,378,297.50	4,378,298	4,333,192	45,106		
	4,378,297.50	4,378,298	4,333,192	45,106		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.41 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	259,506.50	259,506	259,507			
2009	40,958.77	40,959	40,959			
2010	172,048.21	172,048	172,048			
2011	24,265.04	24,265	24,265			
2012	289,474.52	289,475	289,475			
2013	122,786.73	122,787	122,787			
2014	194,702.01	194,702	194,702			
2015	511,276.95	511,277	511,277			
2016	125,210.21	118,950	125,210			
2017	49,440.00	42,024	49,440			
2019	985,498.08	640,574	783,872	201,626	3.50	57,607
2020	17,620.50	9,691	11,859	5,762	4.50	1,280
2021	44,109.42	19,849	24,289	19,820	5.50	3,604
2022	240,887.73	84,311	103,172	137,716	6.50	21,187
2023	1,660,917.30	415,229	508,117	1,152,800	7.50	153,707
2024	2,425,842.93	363,876	445,276	1,980,567	8.50	233,008
2025	22,628.43	1,131	1,384	21,244	9.50	2,236
	7,187,173.33	3,310,654	3,667,639	3,519,535		472,629

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 6.58

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.42 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	867,789.26	867,789	867,789			
2006	1,281,856.64	1,281,857	1,281,857			
2007	3,042,652.35	3,042,652	3,042,652			
2008	2,908,998.47	2,908,998	2,908,998			
2011	256,689.15	248,134	256,689			
2012	365,169.50	328,653	346,891	18,278	1.50	12,185
2013	142,364.69	118,637	125,221	17,144	2.50	6,858
2014	495,556.48	379,928	401,012	94,545	3.50	27,013
2022	1,468,239.56	342,584	361,595	1,106,644	11.50	96,230
2023	33,630,977.05	5,605,275	5,916,335	27,714,643	12.50	2,217,171
2024	8,239,887.66	823,989	869,716	7,370,172	13.50	545,939
	52,700,180.81	15,948,496	16,378,755	36,321,426		2,905,396

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5 5.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	794,926.72	525,526	691,445	103,482	2.82	36,696
2021	1,291,033.02	748,799	985,210	305,823	3.26	93,811
2022	422,631.37	201,595	265,243	157,389	3.84	40,987
2023	231,386.91	82,189	108,138	123,249	4.54	27,147
2024	218,051.69	47,971	63,116	154,935	5.32	29,123
	2,958,029.71	1,606,080	2,113,152	844,878		227,764
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	314,316.45	239,038	231,825	82,491	2.36	34,954
2020	139,867.03	92,466	89,676	50,191	2.82	17,798
2021	29,417.69	17,062	16,547	12,871	3.26	3,948
2022	136,892.33	65,298	63,328	73,565	3.84	19,158
2023	104,183.66	37,006	35,889	68,294	4.54	15,043
2024	73,032.04	16,067	15,582	57,450	5.32	10,799
2025	110,053.90	8,232	7,984	102,070	6.18	16,516
	907,763.10	475,169	460,831	446,932		118,216
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2019	72,209.78	51,962	58,122	14,088	2.53	5,568
2020	89,863.00	59,408	66,451	23,412	2.82	8,302
2021	70,426.41	40,847	45,689	24,737	3.26	7,588
2023	32,810.13	11,654	13,036	19,775	4.54	4,356
2024	70,946.23	15,608	17,458	53,488	5.32	10,054
2025	36,693.64	2,745	3,070	33,623	6.18	5,441
	372,949.19	182,224	203,827	169,122		41,309
	4,238,742.00	2,263,473	2,777,810	1,460,932		387,289

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.8 9.14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	243,833.01	185,996	243,833			
2018	1,528,160.45	1,059,015	1,393,529	134,632	3.32	40,552
2019	570,621.57	364,970	480,254	90,368	3.66	24,691
2020	3,142,823.45	1,794,238	2,360,989	781,835	4.13	189,306
2021	769,040.96	375,446	494,039	275,002	4.72	58,263
2022	1,601,374.43	629,981	828,975	772,400	5.40	143,037
2023	2,397,349.80	693,314	912,313	1,485,037	6.14	241,863
2024	3,973,495.59	704,501	927,034	3,046,462	6.96	437,710
2025	3,141,671.65	187,872	247,216	2,894,456	7.85	368,721
	17,368,370.91	5,995,333	7,888,181	9,480,190		1,504,143
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	880,256.36	671,460	651,199	229,058	2.95	77,647
2018	628,832.36	435,781	422,631	206,201	3.32	62,109
2019	1,730,886.11	1,107,075	1,073,669	657,217	3.66	179,567
2020	2,690,921.03	1,536,247	1,489,891	1,201,031	4.13	290,807
2021	996,770.72	486,623	471,939	524,832	4.72	111,193
2022	1,723,912.24	678,187	657,723	1,066,190	5.40	197,443
2023	1,446,706.58	418,388	405,763	1,040,944	6.14	169,535
2024	2,007,590.08	355,946	345,205	1,662,385	6.96	238,848
2025	1,998,739.29	119,525	115,918	1,882,821	7.85	239,850
	14,104,614.77	5,809,232	5,633,938	8,470,677		1,566,999
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2019	1,476,187.74	944,170	1,056,101	420,086	3.66	114,778
2020	2,114,429.47	1,207,128	1,350,233	764,197	4.13	185,036
2021	1,795,931.52	876,774	980,715	815,216	4.72	172,715
2022	1,550,354.62	609,910	682,215	868,140	5.40	160,767

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2023	598,545.91	173,099	193,620	404,926	6.14	65,949
2024	638,729.13	113,247	126,672	512,057	6.96	73,571
2025	3,376,941.45	201,941	225,881	3,151,060	7.85	401,409
	11,551,119.84	4,126,269	4,615,438	6,935,682		1,174,225
	43,024,105.52	15,930,834	18,137,556	24,886,549		4,245,367
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.9	9.87

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	151,470.08	86,156	113,357	38,113	4.93	7,731
2020	1,825,853.39	901,789	1,186,502	639,352	5.64	113,360
2022	155,830.23	50,723	66,737	89,093	7.25	12,289
2025	415,782.24	19,625	25,821	389,961	10.09	38,648
	2,548,935.94	1,058,293	1,392,417	1,156,519		172,028
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	466,691.13	296,116	287,181	179,510	4.32	41,553
2020	778,452.97	384,478	372,876	405,577	5.64	71,911
2021	72,949.47	30,070	29,163	43,787	6.42	6,820
2022	226,163.76	73,616	71,395	154,769	7.25	21,347
2024	435,612.35	61,596	59,737	375,875	9.10	41,305
2025	145,862.70	6,885	6,677	139,185	10.09	13,794
	2,125,732.38	852,761	827,029	1,298,703		196,730
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	603,388.00	343,207	383,894	219,494	4.93	44,522
2020	491,779.07	242,890	271,684	220,095	5.64	39,024
2021	162,049.64	66,797	74,716	87,334	6.42	13,603
2022	236,527.62	76,990	86,117	150,411	7.25	20,746
2023	172,449.92	40,491	45,291	127,159	8.15	15,602
2024	311,815.88	44,091	49,318	262,498	9.10	28,846
2025	273,742.77	12,921	14,453	259,290	10.09	25,698
	2,251,752.90	827,387	925,473	1,326,280		188,041
	6,926,421.22	2,738,441	3,144,919	3,781,502		556,799

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.8 8.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	535,638.12	339,862	447,163	88,475	4.32	20,480
2019	381,787.38	217,161	285,723	96,064	4.93	19,486
2020	414,682.49	204,812	269,475	145,207	5.64	25,746
2021	310,179.53	127,856	168,223	141,957	6.42	22,112
2022	1,307,895.60	425,720	560,129	747,767	7.25	103,140
2023	547,886.82	128,644	169,260	378,627	8.15	46,457
2025	889,618.07	41,990	55,247	834,371	10.09	82,693
	4,387,688.01	1,486,045	1,955,220	2,432,468		320,114
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	425,376.84	269,902	261,758	163,619	4.32	37,875
2019	314,507.36	178,892	173,494	141,013	4.93	28,603
2020	346,472.52	171,123	165,959	180,513	5.64	32,006
2023	815,413.48	191,459	185,682	629,732	8.15	77,268
2025	813,571.95	38,401	37,242	776,330	10.09	76,941
	2,715,342.15	849,777	824,135	1,891,207		252,693
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2002	82,337.38	79,060	82,337			
2005	284,538.01	263,881	284,538			
2019	305,665.05	173,862	198,682	106,983	4.93	21,700
2020	514,813.65	254,266	290,565	224,249	5.64	39,760
2023	268,096.35	62,949	71,936	196,161	8.15	24,069
2024	1,374,740.74	194,388	222,139	1,152,602	9.10	126,660
2025	111,029.33	5,241	5,989	105,040	10.09	10,410
	2,941,220.51	1,033,647	1,156,186	1,785,035		222,599
	10,044,250.67	3,369,469	3,935,541	6,108,710		795,406

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.7 7.92

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	16,490.72	11,933	15,700	790	5.16	153
2014	38,491.58	26,074	34,306	4,186	5.48	764
2016	325,609.19	200,771	264,158	61,451	5.91	10,398
2018	36,897.65	19,593	25,779	11,119	6.62	1,680
2019	26,522.13	12,654	16,649	9,873	7.12	1,387
2020	69,273.71	28,880	37,998	31,276	7.69	4,067
2021	21,143.06	7,413	9,753	11,390	8.34	1,366
2025	26,522.47	1,117	1,470	25,053	11.38	2,201
	560,950.51	308,435	405,814	155,137		22,016
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1998	6,700.32	6,099	5,915	785	2.69	292
2004	1,216.16	1,029	998	218	3.87	56
2010	45,935.70	34,957	33,902	12,033	4.87	2,471
2011	49,119.84	36,535	35,433	13,687	4.99	2,743
2018	76,939.46	40,855	39,622	37,317	6.62	5,637
2020	58,429.07	24,359	23,624	34,805	7.69	4,526
2021	77,578.44	27,199	26,378	51,200	8.34	6,139
2022	19,945.76	5,577	5,409	14,537	9.02	1,612
2023	69,667.38	14,247	13,817	55,850	9.72	5,746
2025	192,935.29	8,123	7,878	185,057	11.38	16,262
	598,467.42	198,980	192,976	405,491		45,484
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1993	1,810.90	1,717	1,811			
2000	33,228.01	29,616	33,133	95	3.08	31
2001	6,200.60	5,458	6,106	94	3.30	28
2002	17,349.12	15,087	16,879	470	3.49	135
2003	16,279.31	13,981	15,641	638	3.66	174
2004	90,222.97	76,311	85,373	4,849	3.87	1,253
2005	102,817.05	85,575	95,738	7,079	4.08	1,735
2006	20,800.27	17,056	19,082	1,719	4.23	406

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2008	13,098.80	10,385	11,618	1,481	4.57	324
2010	9,187.14	6,991	7,821	1,366	4.87	280
2017	7,110.94	4,104	4,591	2,520	6.23	404
2019	69,640.53	33,225	37,171	32,470	7.12	4,560
2020	107,911.42	44,988	50,331	57,581	7.69	7,488
2021	240,735.39	84,402	94,425	146,310	8.34	17,543
2022	214,947.38	60,099	67,236	147,711	9.02	16,376
2024	201,868.23	25,234	28,231	173,638	10.50	16,537
2025	361,524.72	15,220	17,027	344,497	11.38	30,272
	1,514,732.78	529,449	592,215	922,518		97,546
	2,674,150.71	1,036,864	1,191,005	1,483,146		165,046

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.0 6.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,589.99	3,214	3,214	2,376	8.50	280
2018	10,248.45	3,843	3,843	6,405	12.50	512
	15,838.44	7,057	7,057	8,781		792

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.1 5.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	539,951.02	519,703	539,951			
2007	637,237.38	581,479	604,690	32,547	1.75	18,598
2008	236,121.16	206,606	214,853	21,268	2.50	8,507
2009	314,488.38	259,453	269,810	44,679	3.50	12,765
2010	162,964.81	126,298	131,340	31,625	4.50	7,028
2011	451,363.00	327,238	340,301	111,062	5.50	20,193
2012	368,654.37	248,842	258,775	109,879	6.50	16,904
2013	792,113.30	495,071	514,833	277,280	7.50	36,971
2014	476,076.46	273,744	284,671	191,405	8.50	22,518
2015	1,648,297.12	865,356	899,899	748,398	9.50	78,779
2016	1,270,294.92	603,390	627,476	642,819	10.50	61,221
2017	1,830,420.92	777,929	808,982	1,021,439	11.50	88,821
2018	915,728.07	343,398	357,106	558,622	12.50	44,690
2019	1,013,925.51	329,526	342,680	671,246	13.50	49,722
2020	1,214,941.27	334,109	347,446	867,495	14.50	59,827
2021	2,421,094.90	544,746	566,491	1,854,604	15.50	119,652
2022	2,950,748.68	516,381	536,994	2,413,755	16.50	146,288
2023	2,303,400.56	287,925	299,418	2,003,982	17.50	114,513
2024	1,538,342.77	115,376	119,982	1,418,361	18.50	76,668
2025	1,186,024.58	29,651	30,835	1,155,190	19.50	59,241
	22,272,189.18	7,786,221	8,096,530	14,175,659		1,042,906
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	272,070.63	261,868	268,238	3,833	0.75	3,833
2007	397,958.98	363,138	371,971	25,988	1.75	14,850
2008	194,881.81	170,522	174,670	20,212	2.50	8,085
2009	386,652.36	318,988	326,747	59,905	3.50	17,116
2010	528,508.76	409,594	419,557	108,952	4.50	24,212
2011	46,412.17	33,649	34,467	11,945	5.50	2,172
2012	106,370.79	71,800	73,546	32,824	6.50	5,050
2013	245,409.98	153,381	157,112	88,298	7.50	11,773
2014	495,061.18	284,660	291,584	203,477	8.50	23,938
2015	960,119.93	504,063	516,324	443,796	9.50	46,715
2016	523,955.99	248,879	254,933	269,023	10.50	25,621
2017	608,859.13	258,765	265,059	343,800	11.50	29,896
2018	1,012,779.35	379,792	389,030	623,749	12.50	49,900
2019	553,146.33	179,773	184,146	369,000	13.50	27,333

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	1,269,985.14	349,246	357,741	912,244	14.50	62,913
2021	1,323,741.79	297,842	305,087	1,018,655	15.50	65,720
2022	786,517.05	137,640	140,988	645,529	16.50	39,123
2023	1,635,510.95	204,439	209,412	1,426,099	17.50	81,491
2024	938,712.15	70,403	72,116	866,597	18.50	46,843
2025	778,594.88	19,465	19,938	758,656	19.50	38,905
	13,065,249.35	4,717,907	4,832,667	8,232,582		625,489
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	119,681.95	119,682	119,682			
2006	299,558.28	288,325	244,440	55,119	0.75	55,119
2007	491,013.65	448,050	379,853	111,160	1.75	63,520
2008	601,711.46	526,498	446,361	155,351	2.50	62,140
2009	555,234.09	458,068	388,347	166,888	3.50	47,682
2010	130,973.00	101,504	86,054	44,919	4.50	9,982
2011	37,493.92	27,183	23,046	14,448	5.50	2,627
2012	293,686.51	198,238	168,065	125,622	6.50	19,326
2013	299,610.27	187,256	158,754	140,856	7.50	18,781
2014	509,913.33	293,200	248,573	261,341	8.50	30,746
2015	265,009.96	139,130	117,953	147,057	9.50	15,480
2016	645,329.65	306,532	259,875	385,454	10.50	36,710
2017	190,998.54	81,174	68,819	122,180	11.50	10,624
2018	723,680.35	271,380	230,074	493,606	12.50	39,488
2019	612,456.17	199,048	168,751	443,705	13.50	32,867
2020	522,174.71	143,598	121,741	400,433	14.50	27,616
2021	1,106,649.73	248,996	211,097	895,553	15.50	57,778
2022	842,166.59	147,379	124,947	717,220	16.50	43,468
2023	351,898.78	43,987	37,292	314,607	17.50	17,978
2024	213,446.62	16,008	13,571	199,875	18.50	10,804
2025	658,104.88	16,453	13,949	644,156	19.50	33,034
	9,470,792.44	4,261,689	3,631,243	5,839,549		635,770
	44,808,230.97	16,765,817	16,560,441	28,247,790		2,304,165
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.3						5.14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	290	280	273	9.50	29
2016	295.77	140	135	161	10.50	15
2017	411,182.60	174,753	168,734	242,448	11.50	21,082
2018	25,747.54	9,655	9,322	16,425	12.50	1,314
	437,778.64	184,838	178,472	259,307		22,440

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6 5.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,677	5,848	651	3.65	178
2001	27,339.91	23,603	24,313	3,027	3.84	788
2002	3,719.59	3,174	3,269	450	4.00	112
2003	30,828.76	25,927	26,707	4,122	4.21	979
2004	11,906.59	9,868	10,165	1,742	4.39	397
2005	9,418.96	7,687	7,918	1,501	4.56	329
2006	22,392.50	17,932	18,471	3,921	4.79	819
2007	37,931.66	29,837	30,734	7,197	4.95	1,454
2009	17,602.56	13,389	13,792	3,811	5.19	734
2013	15,373.86	10,513	10,829	4,545	5.78	786
2018	220,480.47	111,607	114,963	105,517	7.32	14,415
2019	308,929.87	140,161	144,376	164,554	7.83	21,016
2020	2,155,616.89	850,175	875,741	1,279,876	8.45	151,465
2021	384,329.95	127,290	131,118	253,212	9.09	27,856
2022	684,283.11	180,377	185,801	498,482	9.78	50,970
2023	216,868.00	41,682	42,935	173,933	10.50	16,565
2024	255,991.05	30,028	30,931	225,060	11.29	19,934
2025	755,399.83	29,838	30,735	724,665	12.16	59,594
	5,164,911.92	1,658,765	1,708,646	3,456,266		368,391
PNG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	57,280	68,110			
2004	167,248.57	138,616	167,249			
2007	13,369.18	10,516	12,910	459	4.95	93
2008	35,075.31	27,190	33,381	1,694	5.07	334
2009	48,114.46	36,596	44,928	3,186	5.19	614
2010	12,089.03	8,994	11,042	1,047	5.33	196
2016	8,023.37	4,764	5,849	2,175	6.50	335
2018	1,346,981.57	681,842	837,089	509,892	7.32	69,657
2020	1,330,094.12	524,589	644,031	686,063	8.45	81,191
2021	407,333.02	134,909	165,626	241,707	9.09	26,590
2022	764,277.51	201,464	247,335	516,943	9.78	52,857
2024	118,030.40	13,845	16,997	101,033	11.29	8,949
2025	305,022.18	12,048	14,791	290,231	12.16	23,868
	4,623,768.46	1,852,653	2,269,339	2,354,430		264,684

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 16-L2						
NET SALVAGE PERCENT.. 0						
2001	29,034.66	25,066	24,428	4,606	3.84	1,199
2003	58,019.67	48,795	47,554	10,466	4.21	2,486
2004	98,699.95	81,803	79,722	18,978	4.39	4,323
2005	80,413.99	65,626	63,957	16,457	4.56	3,609
2006	32,646.90	26,144	25,479	7,168	4.79	1,496
2008	69,039.30	53,519	52,157	16,882	5.07	3,330
2019	106,125.88	48,149	46,924	59,202	7.83	7,561
2020	920,993.58	363,240	353,999	566,994	8.45	67,100
2021	727,173.36	240,840	234,713	492,460	9.09	54,176
2022	603,777.04	159,156	155,107	448,670	9.78	45,876
2023	338,548.00	65,069	63,414	275,134	10.50	26,203
2024	162,408.89	19,051	18,566	143,843	11.29	12,741
2025	782,600.91	30,913	30,127	752,474	12.16	61,881
	4,009,482.13	1,227,371	1,196,147	2,813,335		291,981
	13,798,162.51	4,738,789	5,174,132	8,624,031		925,056

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.3 6.70

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	67,288.99	30,280	27,622	39,667	5.50	7,212
2023	23,301.32	5,825	5,314	17,988	7.50	2,398
2024	328,750.94	49,313	44,984	283,767	8.50	33,384
2025	102,352.01	5,118	4,669	97,683	9.50	10,282
	521,693.26	90,536	82,587	439,106		53,276
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	713,351.62	606,349	517,137	196,214	1.50	130,809
2019	33,841.70	21,997	18,761	15,081	3.50	4,309
2020	50,424.62	27,734	23,654	26,771	4.50	5,949
2021	75,819.30	34,119	29,099	46,720	5.50	8,495
2022	80,244.45	28,086	23,954	56,291	6.50	8,660
2023	99,558.60	24,890	21,228	78,331	7.50	10,444
2025	208,029.43	10,401	8,871	199,159	9.50	20,964
	1,261,269.72	753,576	642,703	618,567		189,630
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	17,961.49	15,267	8,808	9,154	1.50	6,103
2020	45,131.19	24,822	14,320	30,811	4.50	6,847
2021	21,890.53	9,851	5,683	16,207	5.50	2,947
2022	73,558.62	25,746	14,853	58,705	6.50	9,032
2024	407,805.20	61,171	35,290	372,515	8.50	43,825
2025	746,140.09	37,307	21,523	724,617	9.50	76,275
	1,312,487.12	174,164	100,477	1,212,010		145,029
	3,095,450.10	1,018,276	825,767	2,269,683		387,935

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9 12.53

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	102,456.20	92,211	75,548	26,909	1.50	17,939
2013	68,350.42	56,958	46,665	21,685	2.50	8,674
2014	140,132.49	107,435	88,020	52,112	3.50	14,889
2015	39,471.49	27,630	22,637	16,835	4.50	3,741
2016	32,235.43	20,416	16,727	15,509	5.50	2,820
2017	165,977.94	94,055	77,058	88,920	6.50	13,680
2018	8,884.33	4,442	3,639	5,245	7.50	699
2020	89,054.88	32,654	26,753	62,302	9.50	6,558
2024	3,226.50	323	265	2,962	13.50	219
	649,789.68	436,124	357,312	292,478		69,219
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	26,672.91	25,784	26,673			
2012	6,969.59	6,273	6,970			
2014	262,109.02	200,951	262,109			
2016	44,259.57	28,031	44,260			
2017	64,069.97	36,307	64,070			
2018	1,869.95	935	1,870			
2020	61,699.27	22,623	49,576	12,123	9.50	1,276
2022	43,216.83	10,084	22,098	21,119	11.50	1,836
2023	41,520.68	6,920	15,164	26,356	12.50	2,108
2024	35,482.97	3,548	7,775	27,708	13.50	2,052
2025	15,929.11	531	1,164	14,765	14.50	1,018
	603,799.87	341,987	501,728	102,072		8,290
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	70,068.25	67,733	70,068			
2012	14,758.99	13,283	14,759			
2013	2,414.03	2,012	2,414			
2015	4,085.64	2,860	4,086			
2017	81,771.73	46,338	74,481	7,291	6.50	1,122
2018	4,477.95	2,239	3,599	879	7.50	117

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	5,471.06	2,371	3,811	1,660	8.50	195
2022	30,914.09	7,213	11,594	19,320	11.50	1,680
2023	42,498.56	7,083	11,385	31,114	12.50	2,489
	256,460.30	151,132	196,196	60,264		5,603
	1,510,049.85	929,243	1,055,236	454,814		83,112
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.5	5.50

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 399 OTHER TANGIBLE PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
UGI - GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	16,032.00	16,032	16,032			
	16,032.00	16,032	16,032			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 301 ORGANIZATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
1952	96,447.19					
1953	42,516.33		0			
	138,963.52		0			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 389.1 LAND AND LAND RIGHTS - LAND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
2017	6,947,107.66					
	6,947,107.66					
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING - DENVER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 1-2069						
NET SALVAGE PERCENT.. 0						
2019	29,987,923.48	5,049,966	5,211,318	24,776,606	32.11	771,617
2020	1,918,595.10	282,801	291,837	1,626,758	31.81	51,140
2021	647,293.08	80,976	83,563	563,730	31.47	17,913
2022	2,012,444.98	204,867	211,413	1,801,032	30.87	58,342
2023	104,904.91	8,057	8,314	96,590	30.07	3,212
2024	34,006.49	1,680	1,734	32,273	28.89	1,117
2025	56,251.31	1,074	1,108	55,143	25.68	2,147
	34,761,419.35	5,629,421	5,809,287	28,952,133		905,488
READING DATA CENTER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2073						
NET SALVAGE PERCENT.. 0						
2023	11,744,977.98	857,383	884,777	10,860,201	31.75	342,054
2024	8,669,490.58	408,333	421,380	8,248,111	30.35	271,766
	20,414,468.56	1,265,716	1,306,157	19,108,312		613,820
KNITTING MILLS OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. 0						
2022	1,382,240.38	196,831	203,120	1,179,120	21.07	55,962
	1,382,240.38	196,831	203,120	1,179,120		55,962
	56,558,128.29	7,091,968	7,318,564	49,239,565		1,575,270

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.3 2.79

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	3,525,373.71	1,145,746	1,226,044	2,299,330	13.50	170,321
2020	39,198.12	10,779	11,534	27,664	14.50	1,908
2021	10,994.97	2,474	2,647	8,348	15.50	539
2022	823,953.90	144,192	154,299	669,655	16.50	40,585
2024	1,250.26	94	101	1,149	18.50	62
2025	475,773.40	11,894	12,727	463,047	19.50	23,746
	4,876,544.36	1,315,179	1,407,352	3,469,193		237,161

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.6 4.86

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2021	1,076,376.00	968,738	748,671	327,705	0.50	327,705
	1,076,376.00	968,738	748,671	327,705		327,705
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.0						30.45

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	22,821.74	22,822	22,822			
2021	847,064.50	762,358	689,356	157,708	0.50	157,708
2022	1,482,657.72	1,037,860	938,476	544,182	1.50	362,788
2023	4,553,142.98	2,276,571	2,058,570	2,494,573	2.50	997,829
2024	6,182,441.02	1,854,732	1,677,126	4,505,315	3.50	1,287,233
2025	4,789,195.97	478,920	433,060	4,356,136	4.50	968,030
	17,877,323.93	6,433,263	5,819,410	12,057,914		3,773,588
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					3.2	21.11

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2024						
NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,803,866	2,803,866			
	2,803,866.07	2,803,866	2,803,866			
UNITE ERP						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2034						
NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	4,485,291	3,819,935	6,875,882	9.00	763,987
	10,695,816.43	4,485,291	3,819,935	6,875,882		763,987
	13,499,682.50	7,289,157	6,623,801	6,875,882		763,987
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					9.0	5.66

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
ALL OTHER						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	805,219.92	764,959	788,386	16,834	0.50	16,834
2017	1,300,552.48	1,105,470	1,139,326	161,227	1.50	107,485
2018	1,373,844.01	1,030,383	1,061,939	311,905	2.50	124,762
2019	5,970,674.89	3,880,939	3,999,795	1,970,880	3.50	563,109
2020	12,600,894.61	6,930,492	7,142,743	5,458,152	4.50	1,212,923
2021	7,586,244.97	3,413,810	3,518,360	4,067,885	5.50	739,615
2022	8,200,508.34	2,870,178	2,958,079	5,242,429	6.50	806,528
2023	4,678,880.48	1,169,720	1,205,543	3,473,337	7.50	463,112
2024	3,671,205.29	550,681	567,546	3,103,659	8.50	365,136
2025	4,395,756.99	219,788	226,519	4,169,238	9.50	438,867
	50,583,781.98	21,936,420	22,608,237	27,975,545		4,838,371
FULLY AMORTIZED						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2000	802,205.51	802,206	802,206			
2001	18,799.62	18,800	18,800			
2002	447,659.05	447,659	447,659			
2004	1,403,264.52	1,403,265	1,403,265			
2005	122,880.00	122,880	122,880			
2006	2,314,890.18	2,314,890	2,314,890			
2007	3,259,581.05	3,259,581	3,259,581			
2009	440,868.62	440,869	440,869			
2012	2,703,223.05	2,703,223	2,703,223			
2013	259,177.61	259,178	259,178			
2014	740,529.10	740,529	740,529			
2015	220,825.74	220,826	220,826			
	12,733,904.05	12,733,906	12,733,904			
	63,317,686.03	34,670,326	35,342,141	27,975,545		4,838,371

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.8 7.64

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	379,040.93	379,041	379,041			
2011	169,183.92	163,545	160,270	8,914	0.50	8,914
2012	36,120.63	32,509	31,858	4,263	1.50	2,842
2016	1,419,264.44	898,863	880,861	538,403	5.50	97,891
2017	76,271,826.62	43,220,956	42,355,364	33,916,463	6.50	5,217,917
2018	171,914.66	85,957	84,236	87,679	7.50	11,691
2019	43,660,591.71	18,919,444	18,540,541	25,120,051	8.50	2,955,300
2021	7,039,054.95	2,111,716	2,069,425	4,969,630	10.50	473,298
2022	1,553,802.60	362,549	355,288	1,198,515	11.50	104,219
2023	2,737,744.74	456,300	447,161	2,290,584	12.50	183,247
2024	874,535.47	87,454	85,703	788,832	13.50	58,432
2025	268,226.99	8,940	8,761	259,466	14.50	17,894
	134,581,307.66	66,727,274	65,398,509	69,182,799		9,131,645

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.6 6.79

PART IV. EXPERIENCED NET SALVAGE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2021 TRANSACTION YEAR				
305.00			115,195.00	115,195.00
367.00	24.00	1,660.00		1,660.00-
369.00		3,386.00		3,386.00-
375.00	18,008.00			
376.00	4,504,366.00	2,534,160.00		2,534,160.00-
378.00		168,692.00		168,692.00-
379.00		15,105.00		15,105.00-
380.00	12,500,315.00	4,191,361.00		4,191,361.00-
381.00	3,015,928.00	1,237.00	19,201.00	17,964.00
382.00		224,823.00		224,823.00-
383.00		269.00		269.00-
384.00		13,720.00		13,720.00-
385.00		35,290.00		35,290.00-
386.00	269,143.00			
390.10	231,077.00	135.00		135.00-
391.10	661,188.00			
391.20	74,471.00			
391.30	120,424.00			
392.00			526,894.00	526,894.00
393.00	3,091.00			
394.00	869,872.00			
397.00	8,099.00			
398.00	88,752.00	391,820.00		391,820.00-
	22,364,758.00	7,581,658.00	661,290.00	6,920,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
367.00		463.82		463.82-
369.00		4,906.28		4,906.28-
375.00		345.87		345.87-
376.10	2,225,032.94	749,916.61		749,916.61-
376.20	213,665.66	270,874.29		270,874.29-
376.30	3,569,860.81	1,130,258.76		1,130,258.76-
376.50	99.53			
378.00	412,657.26	278,820.57		278,820.57-
379.00	144,233.30	98,843.74		98,843.74-
380.00	12,730,509.62	4,547,450.60		4,547,450.60-
381.00	1,556,577.90	711.28		711.28-
382.00	1,859,075.73	164,128.06		164,128.06-
384.00	719,951.43	2,202.00		2,202.00-
385.00		154.19-		154.19
390.10		969.10		969.10-
391.00	6,694.08			
391.10	136,398.30			
391.20	6,467.49			
391.30	347,005.99			
391.92	165,870.51			
392.00	929,504.65			
392.20			1,548,910.16	1,548,910.16
394.00	684,358.29	21,727.71		21,727.71-
396.00	142,855.69			
397.00	82,937.84			
398.00	143,551.53	150,544.57		150,544.57-
	26,077,308.55	7,422,009.07	1,548,910.16	5,873,098.91-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2023 TRANSACTION YEAR				
325.10	9,986.53			
325.20	35,825.88			
328.00	1,263.20			
329.00	44,784.66			
330.00	18,208.60			
331.00	24,440.72			
332.00	308,348.25			
334.00	89,724.69			
335.00	49,603.72			
337.00	11,062.15			
367.00	13.90	411.88		411.88-
369.00		231.13		231.13-
375.00	4,361.80	1,876.12		1,876.12-
376.10	1,911,104.74	1,693,881.68		1,693,881.68-
376.20	231,008.33	633,299.14		633,299.14-
376.30	3,015,781.26	311,402.09		311,402.09-
376.50	147.85			
378.00	125,958.48	206,791.94		206,791.94-
379.00	87,005.59	85,311.85		85,311.85-
380.00	14,014,376.89	5,345,562.48		5,345,562.48-
381.00	1,365,599.25	35,495.28		35,495.28-
381.10	1,591,780.95	2,076.27		2,076.27-
382.00	147,042.47	117,423.95		117,423.95-
383.00		805.84		805.84-
384.00	73,967.50	82.38		82.38-
390.10	2,990,794.20	395.27		395.27-
392.00	363,110.57			
392.20			887,269.86	887,269.86
394.00		167.21		167.21-
397.00		11.22		11.22-
398.00		79,441.38		79,441.38-
	26,515,302.18	8,514,667.11	887,269.86	7,627,397.25-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2024 TRANSACTION YEAR				
367.00	15,789.19-	5,800.82		5,800.82-
375.00		.25		.25-
376.10	3,278,709.32	1,190,708.39		1,190,708.39-
376.20	340,704.97	682,407.68		682,407.68-
376.30	3,202,277.34	819,607.41		819,607.41-
376.50	9.47			
378.00	1,310.54	165,132.29		165,132.29-
379.00		43,038.20		43,038.20-
380.00	11,321,460.10	4,613,723.58		4,613,723.58-
381.00	1,560,893.83	48,410.73		48,410.73-
381.10		9,684.81		9,684.81-
382.00	168,066.15	65,380.33		65,380.33-
383.00		3,328,106.96		3,328,106.96-
384.00	56,498.06	281.79		281.79-
385.00		984.10		984.10-
386.10		207.86		207.86-
390.10	3,960,071.14	552,199.64		552,199.64-
391.00	28,382.78			
391.10	10,004,713.85			
391.20	1,637.58			
391.30	6,310,627.32			
392.00	22,224.80			
392.20			645,657.43	645,657.43
393.00	1,768.11			
394.00	1,697,038.69			
397.00	31,989.83	2,888.76		2,888.76-
398.00	139,478.08	74,235.76		74,235.76-
	42,112,072.77	11,602,799.36	645,657.43	10,957,141.93-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2025 TRANSACTION YEAR				
367.00		9,570.67		9,570.67-
375.00		12,062.12		12,062.12-
376.10		2,102,594.83		2,102,594.83-
376.20		899,143.51		899,143.51-
376.30		508,772.12		508,772.12-
378.00		313,280.97		313,280.97-
379.00		196,337.52		196,337.52-
380.00		5,022,669.19		5,022,669.19-
381.00		74,865.17		74,865.17-
381.10		18,782.17		18,782.17-
382.00		94,529.64		94,529.64-
383.00		1,028,703.39		1,028,703.39-
384.00		2,577.96		2,577.96-
385.00		87,207.33		87,207.33-
386.00		774.21		774.21-
386.10		1,025.40		1,025.40-
390.10		105,143.54		105,143.54-
392.20			749,272.22	749,272.22
397.00		9,703.27		9,703.27-
398.00		86,622.06		86,622.06-
		10,574,365.07	749,272.22	9,825,092.85-
TOTAL	117,069,441.50	45,695,498.61	4,492,399.67	41,203,098.94-

BOOK IX

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT D
(Fully Projected Future)

ALLOCATED COST OF SERVICE STUDY
AS OF SEPTEMBER 30, 2027

Witness: John D. Taylor
Prepared by: Atrium Economics

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

UGI UTILITIES, INC
GAS DIVISION

EXHIBIT D

ALLOCATED COST OF SERVICE STUDY
FULLY PROJECTED FUTURE TEST YEAR
ENDED SEPTEMBER 30, 2027

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

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I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Allocated Cost of Service Study ("ACOSS") model and related schedules prepared for UGI Utilities, Inc. - Gas Division ("UGI Gas" or "the Company") based on the Fully Projected Future Test Year ending September 30, 2026 ("FPFTY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's ACOSS model used to develop the cost allocation study. The second section, UGI Gas Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section presents the results of the cost-of-service allocation.

1. Purpose of Cost Allocation

The purpose of an ACOSS is to determine the cost-of-service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the ACOSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the ACOSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the ACOSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve, and another pays less than its cost to serve).

2. ACOSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning the Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions, such as Production, Distribution, On-Site and Metering, Customer Services, and Gas Supply. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of gas plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of natural gas services: demand, commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Commodity-related costs are variable costs that vary with the quantity of gas consumed. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. Customer-related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be isolated and directly assigned to a particular customer or group of customers in the same class of service. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing an ACOSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. Where costs cannot be directly assigned, the development of allocation factors by customer class use principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation.

3. Atrium Economics Cost of Service Study Model Overview

The ACOSS is submitted in support of the direct testimony of John D. Taylor as Schedule 1. The ACOSS model presented in this proceeding is a Microsoft Excel based model that allows the user to modify various inputs and assumptions.

ACOSS Model Capabilities

The Atrium Economics' ACOSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of costs of gas, income taxes, working capital, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Standard 3-Step Allocation

The Atrium ACOSS Model follows the standard three-step analysis process: 1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized

components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium ACOSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of administrative and general ("A&G") expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The ACOSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per therm or ccf, per dekatherm or mcf of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the ACOSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. UGI GAS'S COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of UGI Gas's cost allocation:

- Gas Supply
- Storage
- Transmission
- Distribution
- Customer

UGI Gas's assigned functional categories are presented on Schedule 4 - Account Balances and Allocation Methods.

2. Classification

The following classification categories were identified for purposes of UGI Gas's cost allocation:

- Commodity
- Demand
- Customer

UGI Gas's assigned classification categories are presented on Schedule 4.

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes.

3.1.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

Rate Schedule	**ACOSS Customer Class**
Rate R - General Service – Residential Rate RT – General Service - Residential Transportation Rate GL – General Service - Gas Light Service	Rate R
Rate N - General Service – Non-Residential Rate NT - General Service - Non-Residential Transportation	Rate N
Rate DS – Delivery Service	Rate DS
Rate LFD – Large Firm Delivery Service	Rate LFD
Rate XD – Extended Large Firm Delivery Service	Rate XD Firm
Rate IS - Interruptible Service	Interruptible

3.1.2. External Allocation Factors

UGI Gas's External Allocation Factors are presented on Schedule 5. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

Customer Allocation Factors

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

MTR_381	The meters factor is based on the total cost of Meters (FERC Account 381) and Industrial Measuring and Regulating Station Equipment ("M&R equipment"; FERC Account 385) used to serve customers in different rate classes. The calculation relies upon the Company's records, which provide an inventory of each type and size of meter and M&R equipment for a specific rate schedule.
MTR_383	The house regulators factor is determined by the weighted number of customers for the rate cases R and N. Rate R assumes a 1:1 relationship customer/house regulator. The customer weighting for Rate N is determined by the average cost per service relationship between Rate R and Rate N and it relies upon the data contained in the Company's property records which provide the total cost of service lines by customer class.
MTR_385	The Industrial Measuring and Regulating Station Equipment factor is developed using the same methodology for factor MTR_381, excluding Rates R and N.
SVCS_380	The services factor is based on the total cost of Services (FERC Account 380) used to serve customers in different rate classes. The analysis calculation relies upon the Company's records, which provide an inventory of service sizes for a specific rate schedule.
CUST	The customer factor is based on the proforma customer count.
SALES_EXP_R/N	The sales expense factor is calculated using the number of customers for each classification in Rates R and N only.
R_Direct	Direct assignment to Rate R.
XD_Direct	Direct assignment to Rate XD Firm.
Uncollectibles	The Uncollectible Accounts factor (FERC Account 904) is based on a 3-year average of net write-offs by rate class.
Penalty Revenue	Based on a historical analysis of penalty revenue (forfeited discounts) by class.
Customer Deposits	Based on a historical analysis of customer deposits by class.
DIR_910.10	Direct assignment of Energy Efficiency and Conservation Program expenses.
Reconnect	Based on a historical analysis of customer reconnection fees by class.

Commodity and Revenue Allocation Factors

Costs classified as "Commodity" are allocated among customer classes based on the weather-normalized volumes for the FPFTY. The "Revenue" factors directly assign revenues to the relevant customer class.

TOTVOL	Total Volumes based on forecasted billing determinants.
Avg. PGC Volumes	Based on the average daily Purchased Gas Cost (PGC) volumes (mcf) for each service classification in the FPFTY.
Avg. PGC_Choice Volumes	Based on the average daily Purchased Gas Cost (PGC) and Choice volumes (mcf) for each service classification in the FPFTY.
Avg. Daily Throughput	Based on the average daily throughput volumes (mcf) for each service classification in the FPFTY.
Revenues	Based on the Sales Revenue under Present Rates, excluding cost of gas revenues.
GCR	Factor developed to directly assign associated gas cost revenues to the specific class in the FPFTY.

Demand Allocation Factors

Demand-related costs are generally allocated based on peak capacity demand for each customer class.

PEAKDAY_EXCESS	Peak day excess demand for each service classification, excluding interruptible.
PEAKDAY_EXCESS_Excl XD	Peak day excess demand for each service classification, excluding interruptible and XD Firm Service.
AVG_EXCESS	Weighting of the factors derived from average daily volumes and from peak day excess demand for each service classification. Weighting is based on total system load factor.
AVG_EXCESS_Excl XD	Weighting of the factors derived from average daily volumes and from peak day excess demand for each service classification, excluding XD Firm Service (direct assigned) and 100% interruptible. Weighting is based on system load factor for firm service.

3.2.Internal Allocation Factors

UGI Gas's Internal Allocation Factors are presented on Schedule 6. Internal Allocation Factors are developed within the ACOSS model based on the cost ratios of allocated cost using the external allocation factors.

INT_TOTPLT	Total Plant – The factor is based on the total plant in service by customer class.

INT_RATEBASE	Total Rate Base – The factor is based on the derived rate base by customer class.
INT_OM	Operation and Maintenance Expense excluding Administrative and General Expenses – The factor is based on the total customer class allocated O&M Expenses, excluding A&G Expenses.
INT_LABOR	Total Labor Expense – The factor is based on the total customer class allocated labor-related expenses.
INT_REVREQ	Total Revenue Requirement – The factor is based on the total FPFTY expenses at current rates and return on rate base.
INT_DISTEXP	Distribution Operation Expenses – The factor is based on the FPFTY expenses in FERC Accounts 871 through 879.
INT_DMAINT	Distribution Maintenance Expenses – The factors is based on the FPFTY expenses in FERC Accounts 886 through 893.
INT_MAINSXSML	Distribution Plant Mains, excluding small diameters (2” and under) – The factor is based on the allocated plant balances by customer class of FERC Account 376 "Mains" identified as large and direct assigned.
INT_MAINS	Distribution Plant Mains – The factor is based on the allocated plant balances by customer class of FERC Account 376 "Mains".

III. UGI GAS'S ALLOCATED COST OF SERVICE RESULTS

1. **Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates**
2. **Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class**
3. **Schedule 3 - Cost of Service Allocation Study Detail by Account**
4. **Schedule 4 - Account Balances and Allocation Methods**
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6. **Schedule 6 - Internal Allocation Factors**

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 1 - Summary of Cost of Service and Rate of Return Under Current and Proposed Rates

Line No.	Category Description	Total Company	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
1	**Rate Base**							
2	Plant in Service	$ 6,676,559	$ 4,030,975	$ 1,590,903	$ 269,351	$ 453,637	$ 193,367	$ 138,327
3	Accumulated Reserve	(1,736,046)	(1,084,034)	(402,794)	(65,434)	(105,650)	(45,573)	(32,561)
4	Other Rate Base Items	(621,162)	(360,592)	(158,796)	(26,197)	(44,559)	(17,427)	(13,590)
5	**Total Rate Base**	**$ 4,319,351**	**$ 2,586,349**	**$ 1,029,313**	**$ 177,720**	**$ 303,428**	**$ 130,366**	**$ 92,175**
6	**Revenue at Current Rates**							
7	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
8	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
9	N/A	-	-	-	-	-	-	-
10	**Subtotal Base Revenue at Current Rates**	$ 1,220,551	$ 794,595	$ 269,032	$ 36,024	$ 58,792	$ 39,155	$ 22,953
11	Other Revenues	$ 14,131	$ 7,044	$ 2,848	$ 279	$ 445	$ 3,383	$ 132
12	N/A	-	-	-	-	-	-	-
13	**Total Revenue at Current Rates**	**$ 1,234,682**	**$ 801,640**	**$ 271,880**	**$ 36,303**	**$ 59,236**	**$ 42,538**	**$ 23,085**
14	**Expenses at Current Rates**							
15	Purchased Power Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	O&M and A&G Expenses	715,943	522,603	152,903	10,135	14,582	11,344	4,377
17	Depreciation and Amortization Expense	170,518	111,318	36,287	5,953	9,500	4,547	2,912
18	Taxes Other Than Income	15,249	9,392	3,369	670	979	522	317
19	Current Gross Receipts Tax	-	-	-	-	-	-	-
20	Deferred Income Taxes	-	-	-	-	-	-	-
21	Current Income Taxes	50,156	23,849	11,948	2,944	5,148	3,935	2,332
22	**Total Expenses at Current Rates**	**$ 951,866**	**$ 667,162**	**$ 204,507**	**$ 19,702**	**$ 30,209**	**$ 20,348**	**$ 9,938**
23	**Operating Income at Current Rates**	**$ 282,817**	**$ 134,478**	**$ 67,373**	**$ 16,601**	**$ 29,027**	**$ 22,190**	**$ 13,147**
24	Current Rate of Return	6.5%	5.2%	6.5%	9.3%	9.6%	17.0%	14.3%
25	Relative Rate of Return	1.00	0.79	1.00	1.43	1.46	2.60	2.18
26	Current Revenue to Cost Ratio	0.93	0.89	0.92	1.05	1.07	1.45	1.37
27	Current Parity Ratio	1.00	0.96	0.99	1.14	1.16	1.56	1.48
28	**Current Revenue at Equal Rates of Return**							
29	Current Rate of Return	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
30	Current Operating Income at Equal ROR	$ 282,817	$ 169,346	$ 67,396	$ 11,637	$ 19,867	$ 8,536	$ 6,035
31	Current Income Taxes - Equal ROR	50,156	30,032	11,952	2,064	3,523	1,514	1,070
32	Current Gross Receipts Tax - Equal ROR	-	-	-	-	-	-	-
33	Other Expenses - Equal ROR	901,710	637,129	192,554	17,638	26,686	18,834	8,867
34	**Total Margin at Equal Rates of Return**	**$ 1,234,682**	**$ 836,507**	**$ 271,903**	**$ 31,339**	**$ 50,077**	**$ 28,884**	**$ 15,973**
35	Current (Subsidies)/Excesses	$ -	$ (34,867)	$ (23)	$ 4,965	$ 9,160	$ 13,654	$ 7,112
36	**Revenue Requirement at Equal Rates of Return**							
37	Required Return	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%	8.2%
38	Required Operating Income	$ 354,187	$ 212,081	$ 84,404	$ 14,573	$ 24,881	$ 10,690	$ 7,558

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 1 - Summary of Cost of Service and Rate of Return Under Current and Proposed Rates

Line No.	Category Description	Total Company	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
39	**Expenses at Required Return**							
40	Purchased Power Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	O&M and A&G Expenses	715,943	522,603	152,903	10,135	14,582	11,344	4,377
42	Depreciation and Amortization Expense	170,518	111,318	36,287	5,953	9,500	4,547	2,912
43	Taxes Other Than Income	15,249	9,392	3,369	670	979	522	317
44	Gross Receipts Tax	-	-	-	-	-	-	-
45	Deferred Income Taxes	-	-	-	-	-	-	-
46	Current Income Taxes	50,156	30,032	11,952	2,064	3,523	1,514	1,070
47	Gross-up Federal Income Tax	18,972	11,360	4,521	781	1,333	573	405
48	Gross-up State Utility Tax	7,314	4,380	1,743	301	514	221	156
49	Gross-up Bad Debts	1,712	1,602	107	0	2	-	1
50	Gross-up Annual Filing Fee	-	-	-	-	-	-	-
51	**Total Expenses at Required Return**	**$ 979,864**	**$ 690,687**	**$ 210,882**	**$ 19,904**	**$ 30,433**	**$ 18,720**	**$ 9,238**
52	**Total Revenue Requirement at Equal Rates of Return**	**$ 1,334,051**	**$ 902,768**	**$ 295,286**	**$ 34,477**	**$ 55,315**	**$ 29,410**	**$ 16,796**
53	LESS							
54	Other Revenues	14,131	7,044	2,848	279	445	3,383	132
55	N/A	-	-	-	-	-	-	-
56	**Total Base Rate Revenue Requirement at Equal Rates of Re**	**$ 1,319,920**	**$ 895,723**	**$ 292,438**	**$ 34,197**	**$ 54,870**	**$ 26,027**	**$ 16,665**
57	**Base Rate Margin (Deficiency)/Surplus**	**$ (99,369)**	**$ (101,128)**	**$ (23,405)**	**$ 1,827**	**$ 3,922**	**$ 13,128**	**$ 6,288**
58	**Proposed Margin (Decrease)/Increase**	**$ 99,369**	**$ 74,677**	**$ 23,386**	**$ 708**	**$ 736**	**$ (64)**	**$ (73)**
59	**Total Revenue at Proposed Rates**	**$ 1,334,051**	**$ 876,316**	**$ 295,266**	**$ 37,011**	**$ 59,972**	**$ 42,473**	**$ 23,011**
60	**Total Base Rate Revenue at Proposed Rates**	**$ 1,319,920**	**$ 869,272**	**$ 292,418**	**$ 36,732**	**$ 59,528**	**$ 39,090**	**$ 22,879**
61	Proposed Percentage Change to Total Revenue	8.0%	9.3%	8.6%	2.0%	1.2%	-0.2%	-0.3%
62	Proposed Percentage Change to Margin Revenue	12.2%	15.1%	14.4%	2.0%	1.3%	-0.2%	-0.3%
63	Proposed (Subsidies)/Excesses	-	(26,451)	(20)	2,535	4,658	13,063	6,215
64	**Operating Income at Proposed Rates**							
65	Operating Expenses	$ 901,710	$ 643,313	$ 192,558	$ 16,758	$ 25,062	$ 16,413	$ 7,606
66	Proposed Revenue Related Expenses	1,712	1,128	379	48	77	51	30
67	Operating Income Prior to Taxes	430,629	231,876	102,328	20,206	34,834	26,010	15,376
68	Income Taxes	76,442	41,161	18,165	3,587	6,183	4,617	2,729
69	**Total Operating Income at Proposed Rates**	$ 354,187	$ 190,715	$ 84,164	$ 16,619	$ 28,650	$ 21,393	$ 12,646
70	Proposed Rate of Return	8.2%	7.4%	8.2%	9.4%	9.4%	16.4%	13.7%
71	Relative Rate of Return	1.00	0.90	1.00	1.14	1.15	2.00	1.67
72	Proposed Revenue to Cost Ratio	1.00	0.97	1.00	1.07	1.08	1.44	1.37
73	Proposed Parity Ratio	1.00	0.97	1.00	1.07	1.08	1.44	1.37

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
1	**Functional Rate Base**							
2	**Production**							
3	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	**Storage**							
8	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Commodity	$ 23,662	$ 14,841	$ 8,821	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 23,662	$ 14,841	$ 8,821	$ -	$ -	$ -	$ -
12	**Distribution**							
13	Demand	$ 2,559,636	$ 1,140,209	$ 768,484	$ 155,904	$ 283,647	$ 126,376	$ 85,018
14	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ 1,494,043	$ 1,212,437	$ 235,200	$ 19,902	$ 15,876	$ 3,984	$ 6,644
16	Subtotal	$ 4,053,679	$ 2,352,645	$ 1,003,684	$ 175,805	$ 299,522	$ 130,360	$ 91,662
17	**Customer**							
18	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ 228,925	$ 212,732	$ 12,677	$ 1,076	$ 2,378	$ 6	$ 55
21	Subtotal	$ 228,925	$ 212,732	$ 12,677	$ 1,076	$ 2,378	$ 6	$ 55
37	**Total**							
38	Demand	$ 2,572,721	$ 1,146,339	$ 772,615	$ 156,742	$ 285,174	$ 126,376	$ 85,475
39	Commodity	$ 23,662	$ 14,841	$ 8,821	$ -	$ -	$ -	$ -
40	Customer	$ 1,722,968	$ 1,425,169	$ 247,878	$ 20,978	$ 18,254	$ 3,990	$ 6,699
41	**TOTAL RATE BASE**	$ 4,319,351	$ 2,586,349	$ 1,029,313	$ 177,720	$ 303,428	$ 130,366	$ 92,175

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
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Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
42	**Functional Revenue Requirement**							
43	**Production**							
44	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Commodity	$ 1,670	$ 1,231	$ 439	$ -	$ -	$ -	$ -
46	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Subtotal	$ 1,670	$ 1,231	$ 439	$ -	$ -	$ -	$ -
48	**Storage**							
49	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	Commodity	$ 407,380	$ 299,997	$ 107,383	$ -	$ -	$ -	$ -
51	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	Subtotal	$ 407,380	$ 299,997	$ 107,383	$ -	$ -	$ -	$ -
53	**Distribution**							
54	Demand	$ 430,940	$ 189,397	$ 127,743	$ 25,852	$ 46,776	$ 27,131	$ 14,041
55	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	Customer	$ 285,105	$ 219,113	$ 47,234	$ 7,568	$ 6,280	$ 2,274	$ 2,636
57	Subtotal	$ 716,045	$ 408,510	$ 174,978	$ 33,420	$ 53,056	$ 29,404	$ 16,677
58	**Customer**							
59	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Customer	$ 207,034	$ 192,129	$ 11,879	$ 934	$ 2,034	$ 6	$ 52
62	Subtotal	$ 207,034	$ 192,129	$ 11,879	$ 934	$ 2,034	$ 6	$ 52
78	**Total**							
79	Demand	$ 432,861	$ 190,297	$ 128,350	$ 25,975	$ 47,001	$ 27,131	$ 14,108
80	Commodity	$ 409,050	$ 301,228	$ 107,822	$ -	$ -	$ -	$ -
81	Customer	$ 492,139	$ 411,242	$ 59,114	$ 8,502	$ 8,314	$ 2,279	$ 2,688
	TOTAL REVENUE REQUIREMENT AT EQUAL	$ 1,334,051	$ 902,768	$ 295,286	$ 34,477	$ 55,315	$ 29,410	$ 16,796
82	**RATES OF RETURN**							

UGI Utilities Inc. - Gas Division
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FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
83	Demand	32.45%	21.08%	43.47%	75.34%	84.97%	92.25%	83.99%
84	Energy	30.66%	33.37%	36.51%	0.00%	0.00%	0.00%	0.00%
85	Customer	36.89%	45.55%	20.02%	24.66%	15.03%	7.75%	16.01%
86	**Unit Costs**							
87	**Production**							
88	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Commodity	$ 0.00	$ 0.02	$ 0.01	$ -	$ -	$ -	$ -
90	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	**Storage**							
92	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	Commodity	$ 1.20	$ 5.94	$ 3.58	$ -	$ -	$ -	$ -
94	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	**Distribution**							
96	Demand	$ 244.42	$ -	$ -	$ -	$ 30.51	$ 117.94	$ -
97	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	Customer	$ 33.64	$ 28.79	$ 56.48	$ 483.26	$ 820.27	$ 3,508.67	$ 749.83
99	**Customer**							
100	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	Customer	$ 24.43	$ 25.24	$ 14.20	$ 59.64	$ 265.66	$ 8.87	$ 14.78
115	**Total**							
116	Demand	$ 245.51	$ -	$ -	$ -	$ 30.66	$ 117.94	$ -
117	Commodity	$ 1.21	$ 5.97	$ 3.59	$ -	$ -	$ -	$ -
118	Customer (per cust month)	$ 58.07	$ 54.03	$ 70.69	$ 542.90	$ 1,085.93	$ 3,517.55	$ 764.61
119	Demand & Customer (per cust month)	$ 109.15	$ 79.04	$ 224.16	$ 2,201.57	$ 7,224.99	$ 45,386.04	$ 4,777.15

UGI Utilities Inc. - Gas Division
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FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
120	**BILLING DETERMINANTS**							
121	Demand (Billing Demand)	1,763,102				1,533,062	230,040	
122	Commodity	339,204,231	50,491,037	30,008,036	8,868,042	27,341,950	207,826,615	14,668,550
123	Customers (Number of Bills)	8,474,784	7,611,024	836,280	15,660	7,656	648	3,516

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
1	**RATE BASE**									
2	**Plant in Service**									
3	**Intangible Plant**									
4	Organization	301	290	-	185	57	14	16	12	6
5	Franchises & Consents	302	194	-	117	46	8	13	6	4
6	Misc. Intangible Plant	303	290	-	175	69	12	20	8	6
7	Subtotal - Intangible Plant		774	-	477	173	33	49	26	16
					-	-	-	-	-	-
8	**Manufactured Gas Production Plant**				0	0	0	0	0	0
9	Land and Land Rights	304	-	-	-	-	-	-	-	-
10	Structures and Improvements	305	-	-	-	-	-	-	-	-
11	Liquefied Petroleum Gas Equipment	311	-	-	-	-	-	-	-	-
12	Producing Lands	325.1	-	-	-	-	-	-	-	-
13	Production Leaseholds	325.2	-	-	-	-	-	-	-	-
14	Rights-Of-Way	325.4	-	-	-	-	-	-	-	-
15	Other Lands	325.5	-	-	-	-	-	-	-	-
16	Field Measuring and Regulating Station Equipment	328	-	-	-	-	-	-	-	-
17	Other Structures	329	-	-	-	-	-	-	-	-
18	Producing Gas Wells - Well Construction	330	-	-	-	-	-	-	-	-
19	Producing Gas Wells - Well Equipment	331	-	-	-	-	-	-	-	-
20	Field Lines	332	-	-	-	-	-	-	-	-
21	Field Measuring and Regulating Station Equipment	334	-	-	-	-	-	-	-	-
22	Drilling and Cleaning Equipment	335	-	-	-	-	-	-	-	-
23	Other Equipment	337	-	-	-	-	-	-	-	-
24	Subtotal - Manufactured Gas Production Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
25	**Natural Gas Underground Storage Plant**				-	-	-	-	-	-
26	Land	350.1	-	-	-	-	-	-	-	-
27	Rights-of-way	350.2	-	-	-	-	-	-	-	-
28	Structures and Improvements	351	-	-	-	-	-	-	-	-
29	Well Construction	352	-	-	-	-	-	-	-	-
30	Storage leaseholds and rights	352.1	-	-	-	-	-	-	-	-
31	Reservoirs	352.2	-	-	-	-	-	-	-	-
32	Nonrecoverable natural gas	352.3	-	-	-	-	-	-	-	-
33	Lines	353	-	-	-	-	-	-	-	-
34	Compressor Station Equipment	354	-	-	-	-	-	-	-	-
35	Measuring and Regulating Equipment	355	-	-	-	-	-	-	-	-
36	Purification Equipment	356	-	-	-	-	-	-	-	-
37	Other Equipment	357	-	-	-	-	-	-	-	-
38	ARO for Natural Gas Underground Storage Plant	358	-	-	-	-	-	-	-	-
39	Subtotal - Natural Gas Underground Storage Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
40	**Transmission plant**				-	-	-	-	-	-
41	Land and Land Rights	365.1	47	-	22	15	3	6	-	2
42	Rights-of-Way	365.2	868	-	407	274	56	101	-	30
43	Structures and improvements	366	162	-	76	51	10	19	-	6
44	Mains	367	39,468	-	18,491	12,461	2,529	4,607	-	1,380
45	Compressor station equipment	368	-	-	-	-	-	-	-	-
46	Measuring and regulating station equipment	369	6,173	-	2,892	1,949	396	721	-	216
47	Communication equipment	370	3,505	-	1,642	1,107	225	409	-	123
48	Other equipment	371	351	-	164	111	22	41	-	12
49	Testing Equipment	371.1	-	-	-	-	-	-	-	-
50	Subtotal - Transmission plant		50,575	-	23,694	15,967	3,241	5,904	-	1,769

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
51	**Distribution Plant**				-	-	-	-	-	-
52	Land and land rights	374	11,638	-	5,200	3,504	711	1,296	539	388
53	Structures and improvements	375	7,923	-	3,540	2,386	484	882	367	264
54	Mains - Small	376	1,134,433	-	531,480	358,154	72,698	132,422	-	39,678
55	Mains - Large	376	1,908,230	-	894,004	602,451	122,286	222,747	-	66,743
56	Mains - Direct	376	147,691	-	-	-	-	-	147,691	-
57	Compressor station equipment	377	-	-	-	-	-	-	-	-
58	Measuring and regulating station equipment—general	378	229,058	-	102,346	68,969	13,999	25,500	10,604	7,641
59	Measuring and regulating station equipment—city gate check stations	379	81,780	-	36,540	24,624	4,998	9,104	3,786	2,728
60	Services	380	1,937,404	-	1,695,188	227,010	7,850	4,951	511	1,894
61	Meters	381	219,403	-	99,547	94,556	10,619	9,102	1,735	3,844
62	Meter installations	382	153,632	-	69,705	66,211	7,436	6,374	1,215	2,692
63	House regulators	383	10,274	-	9,060	1,214	-	-	-	-
64	House regulatory installations	384	17,829	-	15,722	2,108	-	-	-	-
65	Industrial measuring and regulating station equipment	385	42,671	-	19,360	18,390	2,065	1,770	337	748
66	Other property	386	1,274	-	1,115	149	5	3	0	1
67	Other equipment	387	6,799	-	4,312	1,367	212	357	443	109
68	Other equipment	387.1	-	-	-	-	-	-	-	-
69	Asset retirement costs for distribution plant	388	-	-	-	-	-	-	-	-
70	Subtotal - Distribution Plant		5,910,038	-	3,487,119	1,471,092	243,364	414,507	167,227	126,730
					-	-	-	-	-	-
71	**General Plant**				-	-	-	-	-	-
72	Land and Land Rights	389	14,128	-	10,266	2,048	449	655	516	194
73	Land and Land Rights - Common Allocated	389.1	-	-	-	-	-	-	-	-
74	Structures and Improvements	390	240,055	-	174,437	34,798	7,624	11,136	8,766	3,293
75	Reading Service Center - Common Allocated	390.1	-	-	-	-	-	-	-	-
76	Structures and Improvements - Common Allocated	390.2	-	-	-	-	-	-	-	-
77	Office Furniture and Equipment	391	308,260	-	223,999	44,686	9,790	14,300	11,256	4,229
78	Office Furniture and Equip. - CIS	391.1	-	-	-	-	-	-	-	-
79	Office Furniture and Equip. - System Development Costs	391.2	-	-	-	-	-	-	-	-
80	Office Furniture and Equip. - System Development Costs	391.4	-	-	-	-	-	-	-	-
81	Transportation Equipment	392	87,535	-	63,608	12,689	2,780	4,061	3,196	1,201
82	Transportation Equipment - Common Allocated	392.1	-	-	-	-	-	-	-	-
83	Stores Equipment	393	16	-	12	2	1	1	1	0
84	Tools, Shop, and Garage Equipment	394	46,259	-	33,614	6,706	1,469	2,146	1,689	635
85	Laboratory Equipment	395	438	-	318	63	14	20	16	6
86	Power Operated Equipment	396	13,798	-	10,027	2,000	438	640	504	189
87	Communication Equipment	397	2,364	-	1,718	343	75	110	86	32
88	Misc. Equipment	398	2,320	-	1,686	336	74	108	85	32
89	Other Intangible Property	399	-	-	-	-	-	-	-	-
90	ARO for General Plant	399.1	-	-	-	-	-	-	-	-
					-	-	-	-	-	-
					-	-	-	-	-	-
91	Subtotal - General Plant		715,173	-	519,685	103,672	22,713	33,177	26,115	9,812
					-	-	-	-	-	-
92	**Other Assets**				-	-	-	-	-	-
93	Gas Plant Held for Future Use - Production Plant	101.1	-	-	-	-	-	-	-	-
94	Gas Plant Held for Future Use - Distribution Plant	102	-	-	-	-	-	-	-	-
95	Completed construction not classified - Intangible	105	-	-	-	-	-	-	-	-
96	Completed construction not classified - Distribution	106	-	-	-	-	-	-	-	-
97	Completed construction not classified - General	107	-	-	-	-	-	-	-	-
98	Subtotal - Other Assets		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
99	**Total Plant in Service**		6,676,559	-	4,030,975	1,590,903	269,351	453,637	193,367	138,327

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
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Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
100	**Accumulated Depreciation & Amortization**				-	-	-	-	-	-
101	**Intangible Plant**				-	-	-	-	-	-
102	Organization	301	-	-	-	-	-	-	-	-
103	Franchises & Consents	302	-	-	-	-	-	-	-	-
104	Misc. Intangible Plant	303	-	-	-	-	-	-	-	-
105	Subtotal - Intangible Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
106	**Manufactured Gas Production Plant**				-	-	-	-	-	-
107	Land and Land Rights	304	-	-	-	-	-	-	-	-
108	Structures and Improvements	305	-	-	-	-	-	-	-	-
109	Liquefied Petroleum Gas Equipment	311	-	-	-	-	-	-	-	-
110	Producing Lands	325.1	-	-	-	-	-	-	-	-
111	Production Leaseholds	325.2	-	-	-	-	-	-	-	-
112	Rights-Of-Way	325.4	-	-	-	-	-	-	-	-
113	Other Lands	325.5	-	-	-	-	-	-	-	-
114	Field Measuring and Regulating Station Equipment	328	-	-	-	-	-	-	-	-
115	Other Structures	329	-	-	-	-	-	-	-	-
116	Producing Gas Wells - Well Construction	330	-	-	-	-	-	-	-	-
117	Producing Gas Wells - Well Equipment	331	-	-	-	-	-	-	-	-
118	Field Lines	332	-	-	-	-	-	-	-	-
119	Field Measuring and Regulating Station Equipment	334	-	-	-	-	-	-	-	-
120	Drilling and Cleaning Equipment	335	-	-	-	-	-	-	-	-
121	Other Equipment	337	-	-	-	-	-	-	-	-
122	Subtotal - Manufactured Gas Production Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
123	**Natural Gas Underground Storage Plant**				-	-	-	-	-	-
124	Land	350.1	-	-	-	-	-	-	-	-
125	Rights-of-way	350.2	-	-	-	-	-	-	-	-
126	Structures and Improvements	351	-	-	-	-	-	-	-	-
127	Well Construction	352	-	-	-	-	-	-	-	-
128	Storage leaseholds and rights	352.1	-	-	-	-	-	-	-	-
129	Reservoirs	352.2	-	-	-	-	-	-	-	-
130	Nonrecoverable natural gas	352.3	-	-	-	-	-	-	-	-
131	Lines	353	-	-	-	-	-	-	-	-
132	Compressor Station Equipment	354	-	-	-	-	-	-	-	-
133	Measuring and Regulating Equipment	355	-	-	-	-	-	-	-	-
134	Purification Equipment	356	-	-	-	-	-	-	-	-
135	Other Equipment	357	-	-	-	-	-	-	-	-
136	Lines	353	-	-	-	-	-	-	-	-
137	Subtotal - Natural Gas Underground Storage Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
138	**Transmission plant**				-	-	-	-	-	-
139	Land and Land Rights	365.1	-	-	-	-	-	-	-	-
140	Rights-of-Way	365.2	(594)	-	(278)	(188)	(38)	(69)	-	(21)
141	Structures and improvements	366	(157)	-	(74)	(50)	(10)	(18)	-	(6)
142	Mains	367	(23,932)	-	(11,212)	(7,556)	(1,534)	(2,794)	-	(837)
143	Compressor station equipment	368	-	-	-	-	-	-	-	-
144	Measuring and regulating station equipment	369	(4,437)	-	(2,079)	(1,401)	(284)	(518)	-	(155)
145	Communication equipment	370	(2,631)	-	(1,232)	(831)	(169)	(307)	-	(92)
146	Other equipment	371	(312)	-	(146)	(98)	(20)	(36)	-	(11)
147	Testing Equipment	371.1	-	-	-	-	-	-	-	-
148	Subtotal - Transmission plant		(32,063)	-	(15,021)	(10,123)	(2,055)	(3,743)	-	(1,121)

UGI Utilities Inc. - Gas Division
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Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
149	**Distribution Plant**				-	-	-	-	-	-
150	Land and land rights	374	(1,594)	-	(712)	(480)	(97)	(177)	(74)	(53)
151	Structures and improvements	375	(3,846)	-	(1,719)	(1,158)	(235)	(428)	(178)	(128)
152	Mains - Small	376	(229,141)	-	(107,352)	(72,343)	(14,684)	(26,748)	-	(8,015)
153	Mains - Large	376	(385,439)	-	(180,578)	(121,688)	(24,700)	(44,992)	-	(13,481)
154	Mains - Direct	376	(29,832)	-	-	-	-	-	(29,832)	-
155	Compressor station equipment	377	-	-	-	-	-	-	-	-
156	Measuring and regulating station equipment—general	378	(51,380)	-	(22,957)	(15,470)	(3,140)	(5,720)	(2,379)	(1,714)
157	Measuring and regulating station equipment—city gate check stations	379	(18,454)	-	(8,245)	(5,556)	(1,128)	(2,054)	(854)	(616)
158	Services	380	(508,598)	-	(445,013)	(59,594)	(2,061)	(1,300)	(134)	(497)
159	Meters	381	(91,740)	-	(41,624)	(39,537)	(4,440)	(3,806)	(725)	(1,607)
160	Meter installations	382	(52,438)	-	(23,792)	(22,599)	(2,538)	(2,175)	(415)	(919)
161	House regulators	383	(6,278)	-	(5,536)	(742)	-	-	-	-
162	House regulatory installations	384	(10,128)	-	(8,931)	(1,197)	-	-	-	-
163	Industrial measuring and regulating station equipment	385	(22,284)	-	(10,111)	(9,604)	(1,079)	(924)	(176)	(390)
164	Other property	386	(729)	-	(638)	(85)	(3)	(2)	(0)	(1)
165	Other equipment	387	(4,894)	-	(3,104)	(984)	(152)	(257)	(319)	(78)
166	Asset retirement costs for distribution plant	388	-	-	-	-	-	-	-	-
167	Subtotal - Distribution Plant		(1,416,775)	-	(860,311)	(351,037)	(54,258)	(88,584)	(35,086)	(27,499)
					-	-	-	-	-	-
168	**General Plant**				-	-	-	-	-	-
169	Land and Land Rights	389	-	-	-	-	-	-	-	-
170	Structures and Improvements	390	(70,116)	-	(50,951)	(10,164)	(2,227)	(3,253)	(2,560)	(962)
171	Office Furniture and Equipment	391	(149,964)	-	(108,972)	(21,739)	(4,763)	(6,957)	(5,476)	(2,057)
172	Transportation Equipment	392	(39,498)	-	(28,702)	(5,726)	(1,254)	(1,832)	(1,442)	(542)
173	Stores Equipment	393	(9)	-	(6)	(1)	(0)	(0)	(0)	(0)
174	Tools, Shop, and Garage Equipment	394	(18,442)	-	(13,401)	(2,673)	(586)	(856)	(673)	(253)
175	Laboratory Equipment	395	(223)	-	(162)	(32)	(7)	(10)	(8)	(3)
176	Power Operated Equipment	396	(6,980)	-	(5,072)	(1,012)	(222)	(324)	(255)	(96)
177	Communication Equipment	397	(752)	-	(547)	(109)	(24)	(35)	(27)	(10)
178	Misc. Equipment	398	(1,223)	-	(889)	(177)	(39)	(57)	(45)	(17)
179	Other Intangible Property	399	-	-	-	-	-	-	-	-
180	ARO for General Plant	399.1	-	-	-	-	-	-	-	-
181	0	0	-	-	-	-	-	-	-	-
182	0	0	-	-	-	-	-	-	-	-
183	Subtotal - General Plant		(287,208)	-	(208,701)	(41,634)	(9,121)	(13,324)	(10,487)	(3,940)
					-	-	-	-	-	-
184	**Other Assets**				-	-	-	-	-	-
185	Gas Plant Held for Future Use - Production Plant	101.1	-	-	-	-	-	-	-	-
186	Gas Plant Held for Future Use - Distribution Plant	102	-	-	-	-	-	-	-	-
187	Completed construction not classified - Intangible	105	-	-	-	-	-	-	-	-
188	Completed construction not classified - Distribution	106	-	-	-	-	-	-	-	-
189	Completed construction not classified - General	107	-	-	-	-	-	-	-	-
190	Subtotal - Other Assets		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
191	**Accumulated Provision for Amortization**				-	-	-	-	-	-
192	Intangible Plant	111	-	-	-	-	-	-	-	-
193	Production Plant	111	-	-	-	-	-	-	-	-
194	Natural gas storage and processing plant	111	-	-	-	-	-	-	-	-
195	LNG Terminaling & Processing Plant	111	-	-	-	-	-	-	-	-
196	Transmission plant	111	-	-	-	-	-	-	-	-
197	Distribution plant	111	-	-	-	-	-	-	-	-
198	General plant	111	-	-	-	-	-	-	-	-
199	Subtotal - Accumulated Provision for Amortization		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
200	**Total Accumulated Depreciation & Amortization**		(1,736,046)	-	(1,084,034)	(402,794)	(65,434)	(105,650)	(45,573)	(32,561)

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Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
201	**Other Rate Base Items**				-	-	-	-	-	-
202	Gas Storage Inventory		23,662	-	14,841	8,821	-	-	-	-
203	Cash Working Capital		66,523	-	48,339	9,643	2,113	3,086	2,429	913
204	Cash Working Capital - Purchased Gas Related		-	-	-	-	-	-	-	-
205	Materials & Supplies		28,644	-	20,814	4,152	910	1,329	1,046	393
206	Accumulated Deferred Income Taxes		(716,793)	-	(432,763)	(170,800)	(28,917)	(48,703)	(20,759)	(14,851)
207	Customer Deposits		(23,198)	-	(11,824)	(10,612)	(302)	(271)	(143)	(45)
			-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
208	Total Other Rate Base Items		(621,162)	-	(360,592)	(158,796)	(26,197)	(44,559)	(17,427)	(13,590)
					0	0	0	0	0	0
209	**TOTAL RATE BASE**		4,319,351	-	2,586,349	1,029,313	177,720	303,428	130,366	92,175
					-	-	-	-	-	-
210	**OPERATION AND MAINTENANCE EXPENSE**				-	-	-	-	-	-
211	**Production, Storage, LNG, Transmission, and Distribution Expense**				-	-	-	-	-	-
212	**Manufactured Gas Production Expense**				-	-	-	-	-	-
213	Manufactured gas production operation	710	-	-	-	-	-	-	-	-
214	Steam expenses	711	-	-	-	-	-	-	-	-
215	Other power expenses	712	-	-	-	-	-	-	-	-
216	Duplicate charges—credit	734	-	-	-	-	-	-	-	-
217	Miscellaneous production expenses	735	-	-	-	-	-	-	-	-
218	Rents	736	-	-	-	-	-	-	-	-
219	Maintenance supervision and engineering	740	-	-	-	-	-	-	-	-
220	Maintenance of structures and improvements	741	-	-	-	-	-	-	-	-
221	Maintenance of production equipment	742	-	-	-	-	-	-	-	-
222	Subtotal - Manufactured Gas Production Expense		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
223	**Other Gas Supply Expenses**				-	-	-	-	-	-
224	Natural Gas Transmission Line Purchases	800	-	-	-	-	-	-	-	-
225	Natural Gas City Gate Purchases	804	530,074	-	390,694	139,380	-	-	-	-
226	Liquefied natural gas purchases	804.1	-	-	-	-	-	-	-	-
227	Other gas purchases	805	5	-	4	1	-	-	-	-
228	Purchased gas cost adjustments	805.1	(106,575)	-	(78,552)	(28,023)	-	-	-	-
229	Exchange Gas	806	-	-	-	-	-	-	-	-
230	Purchased Gas Expenses	807	-	-	-	-	-	-	-	-
231	Gas Withdrawn from Storage-Debit	808.1	47,230	-	34,811	12,419	-	-	-	-
232	Gas Delivered to Storage-Credit	808.2	(62,675)	-	(46,195)	(16,480)	-	-	-	-
233	Gas Used for Operations	812	2,169	-	1,599	570	-	-	-	-
234	Other Gas Supply Expenses	813	(5,256)	-	(3,874)	(1,382)	-	-	-	-
235	Subtotal - Other Gas Supply Expenses		404,972	-	298,487	106,485	-	-	-	-

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					-	-	-	-	-	-
236	**Distribution Operation Expenses**				-	-	-	-	-	-
237	Operation supervision and engineering	870	6,320	-	4,008	1,270	197	331	412	101
238	Distribution load dispatching	871	3,427	-	1,039	717	134	197	1,277	63
239	Compressor station labor and expenses	872	-	-	-	-	-	-	-	-
240	Mains and services expenses	874	-	-	-	-	-	-	-	-
241	Mains - Small	874	7,003	-	3,281	2,211	449	817	-	245
242	Mains - Large	874	11,780	-	5,122	3,452	701	1,276	846	382
243	Services	874	15,981	-	13,983	1,872	65	41	4	16
244	Measuring and regulating station expenses—general	875	2,208	-	670	462	86	127	823	40
245	Measuring and regulating station expenses—industrial	876	21	-	-	-	9	8	1	3
246	Measuring and regulating station expenses—city gate check stations	877	461	-	140	96	18	26	172	8
247	Meter and house regulator expenses	878	3,700	-	1,679	1,595	179	154	29	65
248	Customer installations expenses	879	3,364	-	1,526	1,450	163	140	27	59
249	Other expenses	880	7,233	-	4,587	1,454	225	379	472	116
250	Rents	881	74	-	47	15	2	4	5	1
251	Rents - Direct to XD	881.D	577	-	-	-	-	-	577	-
252	Subtotal - Distribution Operation Expenses		62,148	-	36,082	14,594	2,228	3,500	4,645	1,099
					-	-	-	-	-	-
253	**Distribution Maintenance Expenses**				-	-	-	-	-	-
254	Maintenance supervision and engineering	885	2,349	-	900	582	253	326	177	112
255	Maintenance of structures and improvements	886	-	-	-	-	-	-	-	-
256	Maintenance of mains - small	887	8,104	-	3,797	2,558	519	946	-	283
257	Maintenance of mains - large	887	13,631	-	5,927	3,994	811	1,477	979	443
258	Maintenance of compressor station equipment	888	-	-	-	-	-	-	-	-
259	Maintenance of measuring and regulating station equipment—general	889	2,364	-	717	495	92	136	881	43
260	Maintenance of measuring and regulating station equipment—industrial	890	4,015	-	-	-	1,685	1,444	275	610
261	Maintenance of measuring and regulating station equipment—city gate	891	105	-	32	22	4	6	39	2
262	Maintenance of services	892	677	-	592	79	3	2	0	1
263	Maintenance of meters and house regulators	893	40	-	18	17	2	2	0	1
264	Maintenance of other equipment	894	594	-	227	147	64	82	45	28
265	Construction Maintenance	895	-	-	-	-	-	-	-	-
266	Subtotal - Distribution Maintenance Expenses		31,879	-	12,210	7,895	3,433	4,421	2,396	1,523
					-	-	-	-	-	-
267	**Total Production, Storage, LNG, Transmission, and Distribution Expense**		498,999	-	346,779	128,975	5,661	7,921	7,041	2,623
					-	-	-	-	-	-
268	**Customer Accounts, Service, and Sales Expense**				-	-	-	-	-	-
269	**Customer Account**				-	-	-	-	-	-
270	Supervision	901	882	-	792	87	2	1	0	0
271	Meter reading expenses	902	2,972	-	2,669	293	5	3	0	1
272	Customer records and collection expenses	903	27,817	-	24,981	2,745	51	25	2	12
273	Universal Service Program - Direct	903.1	30,831	-	30,831	-	-	-	-	-
274	Uncollectible accounts	904	20,342	-	19,033	1,271	5	22	-	10
275	Miscellaneous customer accounts expenses	905	71	-	63	7	0	0	0	0
276	Subtotal - Customer Account		82,913	-	78,370	4,403	64	50	2	23
					-	-	-	-	-	-
277	**Customer Service & Information Expenses**				-	-	-	-	-	-
278	Supervision	907	90	-	81	9	0	0	0	0
279	Customer assistance expenses	908	1,110	-	1,110	-	-	-	-	-
280	Informational and instructional advertising expenses	909	1,358	-	1,220	134	3	1	0	1
281	Miscellaneous Customer Service & Informational Exp.	910	82	-	74	8	0	0	0	0
282	Energy Efficiency and Conservation Programs	910.1	12,026	-	9,861	791	398	976	-	-
283	Subtotal - Customer Service & Information Expenses		14,666	-	12,345	942	401	977	0	1

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					-	-	-	-	-	-
284	**Sales Expenses**				-	-	-	-	-	-
285	Supervision	911	-	-	-	-	-	-	-	-
286	Demonstrating and selling expenses	912	766	-	690	76	-	-	-	-
287	Advertising expenses	913	526	-	474	52	-	-	-	-
288	Miscellaneous sales expenses	916	-	-	-	-	-	-	-	-
289	Subtotal - Sales Expenses		1,292	-	1,164	128	-	-	-	-
					-	-	-	-	-	-
290	**Total Customer Accounts, Service, and Sales Expense**		98,871	-	91,879	5,473	465	1,028	3	24
					-	-	-	-	-	-
291	**Administrative and General Expenses**				-	-	-	-	-	-
292	Administrative and general salaries	920	36,548	-	26,558	5,298	1,161	1,695	1,335	501
293	Office supplies and expenses	921	19,009	-	13,813	2,756	604	882	694	261
294	Administrative expenses transferred—Credit	922	-	-	-	-	-	-	-	-
295	Outside services employed	923	18,775	-	13,643	2,722	596	871	686	258
296	Outside services employed - Manufactured Gas Plant	923.MGP	1,670	-	1,231	439	-	-	-	-
297	Property insurance	924	361	-	262	52	11	17	13	5
298	Injuries and damages	925	12,048	-	8,755	1,746	383	559	440	165
299	Employee pensions and benefits	926	18,437	-	11,753	3,650	881	1,047	734	373
300	Franchise requirements	927	-	-	-	-	-	-	-	-
301	Regulatory commission expenses	928	1,759	-	1,053	419	72	124	53	38
302	Duplicate charges—Credit	929	-	-	-	-	-	-	-	-
303	General advertising expenses	930.1	171	-	124	25	5	8	6	2
304	Miscellaneous general expenses	930.2	3,979	-	2,891	577	126	185	145	55
305	Rents	931	77	-	56	11	2	4	3	1
306	Maintenance of general plant	932	5,239	-	3,807	759	166	243	191	72
307	Maintenance of general plant	935	-	-	-	-	-	-	-	-
308	Total Administrative and General Expenses		118,072	-	83,945	18,455	4,008	5,633	4,300	1,730
					-	-	-	-	-	-
309	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		715,943	-	522,603	152,903	10,135	14,582	11,344	4,377
					-	-	-	-	-	-
310	**Adjustments, Depreciation and Amortization Expense**				-	-	-	-	-	-
311	**Depreciation Expense**				-	-	-	-	-	-
312	**Intangible Plant**				0	0	0	0	0	0
313	Organization	301	-	-	-	-	-	-	-	-
314	Franchises & Consents	302	-	-	-	-	-	-	-	-
315	Misc. Intangible Plant	303	-	-	-	-	-	-	-	-
316	Subtotal - Intangible Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
317	**Manufactured Gas Production Plant**				0	0	0	0	0	0
318	Land and Land Rights	304	-	-	-	-	-	-	-	-
319	Structures and Improvements	305	-	-	-	-	-	-	-	-
320	Liquefied Petroleum Gas Equipment	311	-	-	-	-	-	-	-	-
321	Producing Lands	325.1	-	-	-	-	-	-	-	-
322	Production Leaseholds	325.2	-	-	-	-	-	-	-	-
323	Rights-Of-Way	325.4	-	-	-	-	-	-	-	-
324	Other Lands	325.5	-	-	-	-	-	-	-	-
325	Field Measuring and Regulating Station Equipment	328	-	-	-	-	-	-	-	-
326	Other Structures	329	-	-	-	-	-	-	-	-
327	Producing Gas Wells - Well Construction	330	-	-	-	-	-	-	-	-
328	Producing Gas Wells - Well Equipment	331	-	-	-	-	-	-	-	-
329	Field Lines	332	-	-	-	-	-	-	-	-
330	Field Measuring and Regulating Station Equipment	334	-	-	-	-	-	-	-	-
331	Drilling and Cleaning Equipment	335	-	-	-	-	-	-	-	-
332	Other Equipment	337	-	-	-	-	-	-	-	-
333	Subtotal - Manufactured Gas Production Plant		-	-	-	-	-	-	-	-

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					-	-	-	-	-	-
334	**Natural Gas Underground Storage Plant**				-	-	-	-	-	-
335	Land	350.1	-	-	-	-	-	-	-	-
336	Rights-of-way	350.2	-	-	-	-	-	-	-	-
337	Structures and Improvements	351	-	-	-	-	-	-	-	-
338	Well Construction	351.01	-	-	-	-	-	-	-	-
339	Storage leaseholds and rights	352.1	-	-	-	-	-	-	-	-
340	Reservoirs	352.2	-	-	-	-	-	-	-	-
341	Nonrecoverable natural gas	352.3	-	-	-	-	-	-	-	-
342	Lines	353	-	-	-	-	-	-	-	-
343	Compressor Station Equipment	354	-	-	-	-	-	-	-	-
344	Measuring and Regulating Equipment	355	-	-	-	-	-	-	-	-
345	Purification Equipment	356	-	-	-	-	-	-	-	-
346	Other Equipment	357	-	-	-	-	-	-	-	-
347	ARO for Natural Gas Underground Storage Plant	358	-	-	-	-	-	-	-	-
348	Subtotal - Natural Gas Underground Storage Plant		-	-	-	-	-	-	-	-
					-	-	-	-	-	-
349	**Transmission plant**				-	-	-	-	-	-
350	Land and Land Rights	365.1	-	-	-	-	-	-	-	-
351	Rights-of-Way	365.2	11	-	5	3	1	1	-	0
352	Structures and improvements	366	0	-	0	0	0	0	-	0
353	Mains	367	399	-	187	126	26	47	-	14
354	Compressor station equipment	368	-	-	-	-	-	-	-	-
355	Measuring and regulating station equipment	369	87	-	41	27	6	10	-	3
356	Communication equipment	370	77	-	36	24	5	9	-	3
357	Other equipment	371	5	-	2	2	0	1	-	0
358	Testing Equipment	371.1	-	-	-	-	-	-	-	-
359	Subtotal - Transmission plant		579	-	271	183	37	68	-	20
					-	-	-	-	-	-
360	**Distribution Plant**				-	-	-	-	-	-
361	Land and land rights	374	43	-	19	13	3	5	2	1
362	Structures and improvements	375	144	-	64	43	9	16	7	5
363	Mains - Small	376	18,275	-	8,562	5,770	1,171	2,133	-	639
364	Mains - Large	376	30,741	-	14,402	9,705	1,970	3,588	-	1,075
365	Mains - Direct	376	2,379	-	-	-	-	-	2,379	-
366	Compressor station equipment	377	-	-	-	-	-	-	-	-
367	Measuring and regulating station equipment—general	378	6,275	-	2,804	1,889	383	699	290	209
368	Measuring and regulating station equipment—city gate check stations	379	2,234	-	998	673	137	249	103	75
369	Services	380	51,721	-	45,255	6,060	210	132	14	51
370	Meters	381	7,851	-	3,562	3,383	380	326	62	138
371	Meter installations	382	3,709	-	1,683	1,598	180	154	29	65
372	House regulators	383	206	-	182	24	-	-	-	-
373	House regulatory installations	384	319	-	281	38	-	-	-	-
374	Industrial measuring and regulating station equipment	385	798	-	362	344	39	33	6	14
375	Other property	386	27	-	23	3	0	0	0	0
376	Other equipment	387	89	-	57	18	3	5	6	1
377	Other equipment	387.1	-	-	-	-	-	-	-	-
378	Asset retirement costs for distribution plant	388	-	-	-	-	-	-	-	-
379	Subtotal - Distribution Plant		124,811	-	78,254	29,562	4,483	7,339	2,899	2,273

UGI Utilities Inc. - Gas Division
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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
380	**General Plant**				-	-	-	-	-	-
381	Land and Land Rights	389	-	-	-	-	-	-	-	-
382	Structures and Improvements	390	8,959	-	6,510	1,299	285	416	327	123
383	Reading Service Center - Common Allocated	390.1	-	-	-	-	-	-	-	-
384	Structures and Improvements - Common Allocated	390.2	-	-	-	-	-	-	-	-
385	Office Furniture and Equipment	391	26,357	-	19,152	3,821	837	1,223	962	362
386	Office Furniture and Equip. - CIS	391.1	-	-	-	-	-	-	-	-
387	Office Furniture and Equip. - System Development Costs	391.2	-	-	-	-	-	-	-	-
388	Office Furniture and Equip. - System Development Costs	391.4	-	-	-	-	-	-	-	-
389	Transportation Equipment	392	8,288	-	6,022	1,201	263	384	303	114
390	Stores Equipment	393	1	-	1	0	0	0	0	0
391	Tools, Shop, and Garage Equipment	394	2,360	-	1,715	342	75	109	86	32
392	Laboratory Equipment	395	22	-	16	3	1	1	1	0
393	Power Operated Equipment	396	833	-	605	121	26	39	30	11
394	Communication Equipment	397	264	-	192	38	8	12	10	4
395	Misc. Equipment	398	86	-	62	12	3	4	3	1
396	Other Intangible Property	399	-	-	-	-	-	-	-	-
397	ARO for General Plant	399.1	-	-	-	-	-	-	-	-
398	Subtotal - General Plant		47,170	-	34,276	6,838	1,498	2,188	1,722	647
					-	-	-	-	-	-
399	**Total - Depreciation Expense**		172,559	-	112,801	36,583	6,018	9,595	4,621	2,940
					-	-	-	-	-	-
400	**Amortization Expense**				-	-	-	-	-	-
401	Amortization of Net Salvage	404.1	9,703	-	7,051	1,407	308	450	354	133
402	Subtotal - Amortization Expense		9,703	-	7,051	1,407	308	450	354	133
					-	-	-	-	-	-
403	**Adjustments**				-	-	-	-	-	-
404	Amount Charged to Clearing Accounts		(11,745)	-	(8,534)	(1,703)	(373)	(545)	(429)	(161)
405	Subtotal - Adjustments		(11,745)	-	(8,534)	(1,703)	(373)	(545)	(429)	(161)
					-	-	-	-	-	-
406	**Total Adjustments, Depreciation and Amortization Expense**		170,518	-	111,318	36,287	5,953	9,500	4,547	2,912
					-	-	-	-	-	-
407	**Taxes**				-	-	-	-	-	-
408	**Taxes Other Than Income Taxes**				-	-	-	-	-	-
409	PURTA & Property Taxes	408.1	1,420	-	857	338	57	96	41	29
410	Taxes Other Than Income Taxes - Payroll	408.1	6,573	-	4,190	1,301	314	373	262	133
411	Taxes Other Than Income Taxes - Excise	408.1	-	-	-	-	-	-	-	-
412	Public Utility Assessment	408.1	6,006	-	3,596	1,431	247	422	181	128
413	PA Local Use and Miscellaneous	408.1	1,250	-	748	298	51	88	38	27
414	Miscellaneous Taxes	408.1	-	-	-	-	-	-	-	-
415	Subtotal - Taxes Other Than Income Taxes		15,249	-	9,392	3,369	670	979	522	317
					-	-	-	-	-	-
416	**Income Taxes**				-	-	-	-	-	-
417	Income Taxes - federal taxes utility operating income	409.1	41,256	-	24,704	9,831	1,697	2,898	1,245	880
418	Income Taxes - State	409.1	8,900	-	5,329	2,121	366	625	269	190
419	Provisions for deferred income taxes, utility operating income	410.1	-	-	-	-	-	-	-	-
420	Provision for deferred income taxes—credit, utility operating income	411.1	-	-	-	-	-	-	-	-
421	Investment Tax credit Adj.	411.4	-	-	-	-	-	-	-	-
422	Subtotal - Income Taxes		50,156	-	30,032	11,952	2,064	3,523	1,514	1,070
					-	-	-	-	-	-
423	**Total Taxes**		65,405	-	39,424	15,321	2,733	4,503	2,036	1,387

UGI Utilities Inc. - Gas Division
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Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
					-	-	-	-	-	-
424	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**				-	-	-	-	-	-
425	**Test Year Expenses at Current Rates**		951,866	-	673,345	204,511	18,822	28,585	17,927	8,676
426	**Return on Rate Base**		354,187	-	212,081	84,404	14,573	24,881	10,690	7,558
427	**Gross Up Items**				-	-	-	-	-	-
428	Gross-up Federal Income Tax		18,972	-	11,360	4,521	781	1,333	573	405
429	Gross-up State Utility Tax		7,314	-	4,380	1,743	301	514	221	156
430	Gross-up Bad Debts		1,712	-	1,602	107	0	2	-	1
431	Gross-up Annual Filing Fee		-	-	-	-	-	-	-	-
432	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		1,334,051	-	902,768	295,286	34,477	55,315	29,410	16,796
433	**INTERNAL ALLOCATION FACTORS**									
434	INT_TOTPLT		6,675,785	-	4,030,498	1,590,731	269,318	453,588	193,341	138,311
435	INT_RATEBASE		4,319,351	-	2,586,349	1,029,313	177,720	303,428	130,366	92,175
436	INT_OM		192,898	-	140,171	27,963	6,126	8,949	7,044	2,647
437	INT_LABOR		46,421	-	29,590	9,191	2,217	2,636	1,849	938
438	INT_REV_REQ		1,334,051	-	902,768	295,286	34,477	55,315	29,410	16,796
439	INT_DISTEXP	871-879	40,881	-	24,234	8,811	1,461	2,493	3,124	758
440	INT_DMAINT	886-893	28,936	-	11,083	7,166	3,116	4,013	2,175	1,383
441	INT_MAINSXSML		2,055,921	-	894,004	602,451	122,286	222,747	147,691	66,743
442	INT_MAINS		3,190,354	-	1,425,484	960,605	194,984	355,169	147,691	106,422
443	last line for internals									

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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Total Check	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
444	Operating Revenue									
445	Residential Sales	480	496,238	0	301,857	98,902	21,919	35,772	23,824	13,966
446	Commercial and industrial sales	481	198,491	0	120,740	39,560	8,767	14,308	9,529	5,586
447	Lg Transport/Other, Interruptible Sales	489	120,850	0	73,512	24,086	5,338	8,712	5,802	3,401
448	Residential Sales - GCR	480.GCR	298,400	0	219,937	78,463	-	-	-	-
449	Commercial and industrial sales - GCR	481.GCR	106,572	0	78,549	28,023	-	-	-	-
450	Lg Transport/Other, Interruptible Sales - GCR	489.3	-	0	-	-	-	-	-	-
451	Forfeited Discounts	487	6,337	0	3,892	1,808	155	245	165	71
452	Miscellaneous service Revenue	488	2,142	0	1,450	474	55	89	47	27
453	Miscellaneous service Revenue - Reconnection Fees	488	-	0	-	-	-	-	-	-
454	Revenues from transportation of gas of others XD	489.3	1,036	0	-	-	-	-	1,036	-
455	Rent from Gas Properties	493	215	0	130	51	9	15	6	4
456	Rent from Gas Properties	493.XD	2,077	0	-	-	-	-	2,077	-
457	Other gas revenues	495	2,324	0	1,573	514	60	96	51	29
458	Total Operating Revenue		1,234,682	-	801,640	271,880	36,303	59,236	42,538	23,085
459	NET INCOME AT CURRENT RATES		282,817	0	128,294	67,370	17,482	30,651	24,611	14,408

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	290	INT_LABOR					
5	Franchises & Consents	302.0	194	INT_TOTPLT					
6	Misc. Intangible Plant	303.0	290	INT_TOTPLT					
7	Subtotal - Intangible Plant		774						
8	**Manufactured Gas Production Plant**								
9	Land and Land Rights	304.0	0						
10	Structures and Improvements	305.0	0						
11	Liquefied Petroleum Gas Equipment	311.0	0						
12	Producing Lands	325.1	0						
13	Production Leaseholds	325.2	0						
14	Rights-Of-Way	325.4	0						
15	Other Lands	325.5	0						
16	Field Measuring and Regulating Station Equipment	328.0	0						
17	Other Structures	329.0	0						
18	Producing Gas Wells - Well Construction	330.0	0						
19	Producing Gas Wells - Well Equipment	331.0	0						
20	Field Lines	332.0	0						
21	Field Measuring and Regulating Station Equipment	334.0	0						
22	Drilling and Cleaning Equipment	335.0	0						
23	Other Equipment	337.0	0						
24	Subtotal - Manufactured Gas Production Plant		-						
25	**Natural Gas Underground Storage Plant**								
26	Land	350.1	0						
27	Rights-of-way	350.2	0						
28	Structures and Improvements	351.0	0						
29	Well Construction	352.0	0						
30	Storage leaseholds and rights	352.1	0						
31	Reservoirs	352.2	0						
32	Nonrecoverable natural gas	352.3	0						
33	Lines	353.0	0						
34	Compressor Station Equipment	354.0	0						
35	Measuring and Regulating Equipment	355.0	0						
36	Purification Equipment	356.0	0						
37	Other Equipment	357.0	0						
38	ARO for Natural Gas Underground Storage Plant	358.0	0						
39	Subtotal - Natural Gas Underground Storage Plant		-						
40	**Transmission plant**								
41	Land and Land Rights	365.1	47		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
42	Rights-of-Way	365.2	868		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
43	Structures and improvements	366.0	162		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
44	Mains	367.0	39,468		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
45	Compressor station equipment	368.0	0		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
46	Measuring and regulating station equipment	369.0	6,173		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
47	Communication equipment	370.0	3,505		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
48	Other equipment	371.0	351		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
49	Testing Equipment	371.1	0		TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD		
50	Subtotal - Transmission plant		50,575						

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
51	**Distribution Plant**								
52	Land and land rights	374.0	11,638	INT_MAINS					
53	Structures and improvements	375.0	7,923	INT_MAINS					
54	Mains - Small	376.0	1,134,433		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
55	Mains - Large	376.0	1,908,230		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
56	Mains - Direct	376.0	147,691		DISTRIBUTION	DEMAND	XD_Direct		
57	Compressor station equipment	377.0	0						
58	Measuring and regulating station equipment—general	378.0	229,058	INT_MAINS					
59	Measuring and regulating station equipment—city gate check stations	379.0	81,780	INT_MAINS					
60	Services	380.0	1,937,404		DISTRIBUTION	CUSTOMER			SVCS_380
61	Meters	381.0	219,403		DISTRIBUTION	CUSTOMER			MTRS_381
62	Meter installations	382.0	153,632		DISTRIBUTION	CUSTOMER			MTRS_381
63	House regulators	383.0	10,274		DISTRIBUTION	CUSTOMER			MTRS_383
64	House regulatory installations	384.0	17,829		DISTRIBUTION	CUSTOMER			MTRS_383
65	Industrial measuring and regulating station equipment	385.0	42,671		DISTRIBUTION	CUSTOMER			MTRS_381
66	Other property	386.0	1,274		DISTRIBUTION	CUSTOMER			SVCS_380
67	Other equipment	387.0	6,799	INT_DISTEXP					
68	Other equipment	387.1	0	INT_DISTEXP					
69	Asset retirement costs for distribution plant	388.0	0						
70	Subtotal - Distribution Plant		5,910,038						
71	**General Plant**								
72	Land and Land Rights	389.0	14,128	INT_OM					
73	Land and Land Rights - Common Allocated	389.1	0	INT_OM					
74	Structures and Improvements	390.0	240,055	INT_OM					
75	Reading Service Center - Common Allocated	390.1	0	INT_OM					
76	Structures and Improvements - Common Allocated	390.2	0	INT_OM					
77	Office Furniture and Equipment	391.0	308,260	INT_OM					
78	Office Furniture and Equip. - CIS	391.1	0	INT_OM					
79	Office Furniture and Equip. - System Development Costs	391.2	0	INT_OM					
80	Office Furniture and Equip. - System Development Costs	391.4	0	INT_OM					
81	Transportation Equipment	392.0	87,535	INT_OM					
82	Transportation Equipment - Common Allocated	392.1	0	INT_OM					
83	Stores Equipment	393.0	16	INT_OM					
84	Tools, Shop, and Garage Equipment	394.0	46,259	INT_OM					
85	Laboratory Equipment	395.0	438	INT_OM					
86	Power Operated Equipment	396.0	13,798	INT_OM					
87	Communication Equipment	397.0	2,364	INT_OM					
88	Misc. Equipment	398.0	2,320	INT_OM					
89	Other Intangible Property	399.0	0						
90	ARO for General Plant	399.1	0						
91	Subtotal - General Plant		715,173						
92	**Other Assets**								
93	Gas Plant Held for Future Use - Production Plant	101.1	0						
94	Gas Plant Held for Future Use - Distribution Plant	102.0	0						
95	Completed construction not classified - Intangible	105.0	0						
96	Completed construction not classified - Distribution	106.0	0						
97	Completed construction not classified - General	107.0	0						
98	Subtotal - Other Assets		-						
99	**Total Plant in Service**		6,676,559						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
100	**Accumulated Depreciation & Amortization**								
101	**Intangible Plant**								
102	Organization	301.0	0	INT_LABOR	-	-	-	-	-
103	Franchises & Consents	302.0	0	INT_TOTPLT	-	-	-	-	-
104	Misc. Intangible Plant	303.0	0	INT_TOTPLT	-	-	-	-	-
105	Subtotal - Intangible Plant		-						
106	**Manufactured Gas Production Plant**								
107	Land and Land Rights	304.0	0	-	-	-	-	-	-
108	Structures and Improvements	305.0	0	-	-	-	-	-	-
109	Liquefied Petroleum Gas Equipment	311.0	0	-	-	-	-	-	-
110	Producing Lands	325.1	0	-	-	-	-	-	-
111	Production Leaseholds	325.2	0	-	-	-	-	-	-
112	Rights-Of-Way	325.4	0	-	-	-	-	-	-
113	Other Lands	325.5	0	-	-	-	-	-	-
114	Field Measuring and Regulating Station Equipment	328.0	0	-	-	-	-	-	-
115	Other Structures	329.0	0	-	-	-	-	-	-
116	Producing Gas Wells - Well Construction	330.0	0	-	-	-	-	-	-
117	Producing Gas Wells - Well Equipment	331.0	0	-	-	-	-	-	-
118	Field Lines	332.0	0	-	-	-	-	-	-
119	Field Measuring and Regulating Station Equipment	334.0	0	-	-	-	-	-	-
120	Drilling and Cleaning Equipment	335.0	0	-	-	-	-	-	-
121	Other Equipment	337.0	0	-	-	-	-	-	-
122	Subtotal - Manufactured Gas Production Plant		-						
123	**Natural Gas Underground Storage Plant**								
124	Land	350.1	0	-	-	-	-	-	-
125	Rights-of-way	350.2	0	-	-	-	-	-	-
126	Structures and Improvements	351.0	0	-	-	-	-	-	-
127	Well Construction	352.0	0	-	-	-	-	-	-
128	Storage leaseholds and rights	352.1	0	-	-	-	-	-	-
129	Reservoirs	352.2	0	-	-	-	-	-	-
130	Nonrecoverable natural gas	352.3	0	-	-	-	-	-	-
131	Lines	353.0	0	-	-	-	-	-	-
132	Compressor Station Equipment	354.0	0	-	-	-	-	-	-
133	Measuring and Regulating Equipment	355.0	0	-	-	-	-	-	-
134	Purification Equipment	356.0	0	-	-	-	-	-	-
135	Other Equipment	357.0	0	-	-	-	-	-	-
136	Lines	353.0	0	-	-	-	-	-	-
137	Subtotal - Natural Gas Underground Storage Plant		-						
138	**Transmission plant**								
139	Land and Land Rights	365.1	0	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
140	Rights-of-Way	365.2	(594)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
141	Structures and improvements	366.0	(157)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
142	Mains	367.0	(23,932)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
143	Compressor station equipment	368.0	0	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
144	Measuring and regulating station equipment	369.0	(4,437)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
145	Communication equipment	370.0	(2,631)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
146	Other equipment	371.0	(312)	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
147	Testing Equipment	371.1	0	0	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
148	Subtotal - Transmission plant		(32,063)						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
149	**Distribution Plant**								
150	Land and land rights	374.0	(1,594)	INT_MAINS	0	0	0	-	-
151	Structures and improvements	375.0	(3,846)	INT_MAINS	0	0	0	-	-
152	Mains - Small	376.0	(229,141)	0	DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD	-	-
153	Mains - Large	376.0	(385,439)	0	DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD	-	-
154	Mains - Direct	376.0	(29,832)	0	DISTRIBUTION	DEMAND	XD_Direct	-	-
155	Compressor station equipment	377.0	0	0	0	0	0	-	-
156	Measuring and regulating station equipment—general	378.0	(51,380)	INT_MAINS	0	0	0	-	-
157	Measuring and regulating station equipment—city gate check stations	379.0	(18,454)	INT_MAINS	0	0	0	-	-
158	Services	380.0	(508,598)	0	DISTRIBUTION	CUSTOMER	0	-	SVCS_380
159	Meters	381.0	(91,740)	0	DISTRIBUTION	CUSTOMER	0	-	MTRS_381
160	Meter installations	382.0	(52,438)	0	DISTRIBUTION	CUSTOMER	0	-	MTRS_381
161	House regulators	383.0	(6,278)	0	DISTRIBUTION	CUSTOMER	0	-	MTRS_383
162	House regulatory installations	384.0	(10,128)	0	DISTRIBUTION	CUSTOMER	0	-	MTRS_383
163	Industrial measuring and regulating station equipment	385.0	(22,284)	0	DISTRIBUTION	CUSTOMER	0	-	MTRS_381
164	Other property	386.0	(729)	0	DISTRIBUTION	CUSTOMER	0	-	SVCS_380
165	Other equipment	387.0	(4,894)	INT_DISTEXP	0	0	0	-	-
166	Asset retirement costs for distribution plant	388.0	0	0	0	0	0	-	-
167	Subtotal - Distribution Plant		(1,416,775)						
168	**General Plant**								
169	Land and Land Rights	389.0	0	INT_OM	-	-	-	-	-
170	Structures and Improvements	390.0	(70,116)	INT_OM	-	-	-	-	-
171	Office Furniture and Equipment	391.0	(149,964)	INT_OM	-	-	-	-	-
172	Transportation Equipment	392.0	(39,498)	INT_OM	-	-	-	-	-
173	Stores Equipment	393.0	(9)	INT_OM	-	-	-	-	-
174	Tools, Shop, and Garage Equipment	394.0	(18,442)	INT_OM	-	-	-	-	-
175	Laboratory Equipment	395.0	(223)	INT_OM	-	-	-	-	-
176	Power Operated Equipment	396.0	(6,980)	INT_OM	-	-	-	-	-
177	Communication Equipment	397.0	(752)	INT_OM	-	-	-	-	-
178	Misc. Equipment	398.0	(1,223)	INT_OM	-	-	-	-	-
179	Other Intangible Property	399.0	0	-	-	-	-	-	-
180	ARO for General Plant	399.1	0	-	-	-	-	-	-
181	0	0.0	0	-	-	-	-	-	-
182	0	0.0	0	-	-	-	-	-	-
183	Subtotal - General Plant		(287,208)						
184	**Other Assets**								
185	Gas Plant Held for Future Use - Production Plant	101.1	0	-	-	-	-	-	-
186	Gas Plant Held for Future Use - Distribution Plant	102.0	0	-	-	-	-	-	-
187	Completed construction not classified - Intangible	105.0	0	-	-	-	-	-	-
188	Completed construction not classified - Distribution	106.0	0	-	-	-	-	-	-
189	Completed construction not classified - General	107.0	0	-	-	-	-	-	-
190	Subtotal - Other Assets		-						
191	**Accumulated Provision for Amortization**								
192	Intangible Plant	111.0	0						
193	Production Plant	111.0	0						
194	Natural gas storage and processing plant	111.0	0						
195	LNG Terminaling & Processing Plant	111.0	0						
196	Transmission plant	111.0	0						
197	Distribution plant	111.0	0						
198	General plant	111.0	0						
199	Subtotal - Accumulated Provision for Amortization		-						
200	**Total Accumulated Depreciation & Amortization**		(1,736,046)						

UGI Utilities Inc. - Gas Division
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
201	**Other Rate Base Items**								
202	Gas Storage Inventory		23,662		STORAGE	COMMODITY		Avg. PGC_Choice Volumes	
203	Cash Working Capital		66,523	INT_OM					
204	Cash Working Capital - Purchased Gas Related		0		STORAGE	COMMODITY		Avg. PGC Volumes	
205	Materials & Supplies		28,644	INT_OM					
206	Accumulated Deferred Income Taxes		(716,793)	INT_TOTPLT					
207	Customer Deposits		(23,198)		DISTRIBUTION	CUSTOMER			Customer Deposits
			0						
			0						
			0						
208	**Total Other Rate Base Items**		(621,162)						
209	**TOTAL RATE BASE**		4,319,351						
210	**OPERATION AND MAINTENANCE EXPENSE**								
211	**Production, Storage, LNG, Transmission, and Distribution Expense**								
212	**Manufactured Gas Production Expense**								
213	Manufactured gas production operation	710.0	0						
214	Steam expenses	711.0	0						
215	Other power expenses	712.0	0						
216	Duplicate charges—credit	734.0	0						
217	Miscellaneous production expenses	735.0	0		PRODUCTION	COMMODITY		Avg. PGC Volumes	
218	Rents	736.0	0						
219	Maintenance supervision and engineering	740.0	0						
220	Maintenance of structures and improvements	741.0	0						
221	Maintenance of production equipment	742.0	0		PRODUCTION	COMMODITY		Avg. PGC Volumes	
222	**Subtotal - Manufactured Gas Production Expense**		-						
223	**Other Gas Supply Expenses**								
224	Natural Gas Transmission Line Purchases	800.0	0		STORAGE	COMMODITY		GCR	
225	Natural Gas City Gate Purchases	804.0	530,074		STORAGE	COMMODITY		GCR	
226	Liquefied natural gas purchases	804.1	0		STORAGE	COMMODITY		GCR	
227	Other gas purchases	805.0	5		STORAGE	COMMODITY		GCR	
228	Purchased gas cost adjustments	805.1	(106,575)		STORAGE	COMMODITY		GCR	
229	Exchange Gas	806.0	0		STORAGE	COMMODITY		GCR	
230	Purchased Gas Expenses	807.0	0		STORAGE	COMMODITY		GCR	
231	Gas Withdrawn from Storage-Debit	808.1	47,230		STORAGE	COMMODITY		GCR	
232	Gas Delivered to Storage-Credit	808.2	(62,675)		STORAGE	COMMODITY		GCR	
233	Gas Used for Operations	812.0	2,169		STORAGE	COMMODITY		GCR	
234	Other Gas Supply Expenses	813.0	(5,256)		STORAGE	COMMODITY		GCR	
235	**Subtotal - Other Gas Supply Expenses**		404,972						

UGI Utilities Inc. - Gas Division
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
236	**Distribution Operation Expenses**								
237	Operation supervision and engineering	870.0	6,320	INT_DISTEXP					
238	Distribution load dispatching	871.0	3,427		DISTRIBUTION	DEMAND	AVG_EXCESS		
239	Compressor station labor and expenses	872.0	0						
240	Mains and services expenses	874.0	0		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
241	Mains - Small	874.0	7,003		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
242	Mains - Large	874.0	11,780	INT_MAINSXSML					
243	Services	874.0	15,981		DISTRIBUTION	CUSTOMER			SVCS_380
244	Measuring and regulating station expenses—general	875.0	2,208		DISTRIBUTION	DEMAND	AVG_EXCESS		
245	Measuring and regulating station expenses—industrial	876.0	21		DISTRIBUTION	CUSTOMER			MTRS_385
246	Measuring and regulating station expenses—city gate check stations	877.0	461		DISTRIBUTION	DEMAND	AVG_EXCESS		
247	Meter and house regulator expenses	878.0	3,700		DISTRIBUTION	CUSTOMER			MTRS_381
248	Customer installations expenses	879.0	3,364		DISTRIBUTION	CUSTOMER			MTRS_381
249	Other expenses	880.0	7,233	INT_DISTEXP					
250	Rents	881.0	74	INT_DISTEXP					
251	Rents - Direct to XD	881.D	577		DISTRIBUTION	CUSTOMER			XD_Direct
252	Subtotal - Distribution Operation Expenses		62,148						
253	**Distribution Maintenance Expenses**								
254	Maintenance supervision and engineering	885.0	2,349	INT_DMAINT					
255	Maintenance of structures and improvements	886.0	0	INT_MAINS					
256	Maintenance of mains - small	887.0	8,104		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
257	Maintenance of mains - large	887.0	13,631	INT_MAINSXSML					
258	Maintenance of compressor station equipment	888.0	0		DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD		
259	Maintenance of measuring and regulating station equipment—general	889.0	2,364		DISTRIBUTION	DEMAND	AVG_EXCESS		
260	Maintenance of measuring and regulating station equipment—industrial	890.0	4,015		DISTRIBUTION	CUSTOMER			MTRS_385
261	Maintenance of measuring and regulating station equipment—city gate	891.0	105		DISTRIBUTION	DEMAND	AVG_EXCESS		
262	Maintenance of services	892.0	677		DISTRIBUTION	CUSTOMER			SVCS_380
263	Maintenance of meters and house regulators	893.0	40		DISTRIBUTION	CUSTOMER			MTRS_381
264	Maintenance of other equipment	894.0	594	INT_DMAINT					
265	Construction Maintenance	895.0	0	INT_DMAINT					
266	Subtotal - Distribution Maintenance Expenses		31,879						
267	**Total Production, Storage, LNG, Transmission, and Distribution Expense**		498,999						
268	**Customer Accounts, Service, and Sales Expense**								
269	**Customer Account**								
270	Supervision	901.0	882		CUSTOMER	CUSTOMER			CUST
271	Meter reading expenses	902.0	2,972		CUSTOMER	CUSTOMER			CUST
272	Customer records and collection expenses	903.0	27,817		CUSTOMER	CUSTOMER			CUST
273	Universal Service Program - Direct	903.1	30,831		CUSTOMER	CUSTOMER			R_Direct
274	Uncollectible accounts	904.0	20,342		CUSTOMER	CUSTOMER			Uncollectibles
275	Miscellaneous customer accounts expenses	905.0	71		CUSTOMER	CUSTOMER			CUST
276	Subtotal - Customer Account		82,913						
277	**Customer Service & Information Expenses**								
278	Supervision	907.0	90		CUSTOMER	CUSTOMER			CUST
279	Customer assistance expenses	908.0	1,110		CUSTOMER	CUSTOMER			R_Direct
280	Informational and instructional advertising expenses	909.0	1,358		CUSTOMER	CUSTOMER			CUST
281	Miscellaneous Customer Service & Informational Exp.	910.0	82		CUSTOMER	CUSTOMER			CUST
282	Energy Efficiency and Conservation Programs	910.1	12,026		CUSTOMER	CUSTOMER			DIR_910.10
283	Subtotal - Customer Service & Information Expenses		14,666						

UGI Utilities Inc. - Gas Division
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
284	**Sales Expenses**								
285	Supervision	911.0	0		CUSTOMER	CUSTOMER			SALES_EXP_R/N
286	Demonstrating and selling expenses	912.0	766		CUSTOMER	CUSTOMER			SALES_EXP_R/N
287	Advertising expenses	913.0	526		CUSTOMER	CUSTOMER			SALES_EXP_R/N
288	Miscellaneous sales expenses	916.0	0		CUSTOMER	CUSTOMER			SALES_EXP_R/N
289	Subtotal - Sales Expenses		1,292						
290	**Total Customer Accounts, Service, and Sales Expense**		98,871						
291	**Administrative and General Expenses**								
292	Administrative and general salaries	920.0	36,548	INT_OM					
293	Office supplies and expenses	921.0	19,009	INT_OM					
294	Administrative expenses transferred—Credit	922.0	0	INT_OM					
295	Outside services employed	923.0	18,775	INT_OM					
296	Outside services employed - Manufactured Gas Plant	923.MGP	1,670		PRODUCTION	COMMODITY		Avg. PGC Volumes	
297	Property insurance	924.0	361	INT_OM					
298	Injuries and damages	925.0	12,048	INT_OM					
299	Employee pensions and benefits	926.0	18,437	INT_LABOR					
300	Franchise requirements	927.0	0						
301	Regulatory commission expenses	928.0	1,759	INT_RATEBASE					
302	Duplicate charges—Credit	929.0	0						
303	General advertising expenses	930.1	171	INT_OM					
304	Miscellaneous general expenses	930.2	3,979	INT_OM					
305	Rents	931.0	77	INT_OM					
306	Maintenance of general plant	932.0	5,239	INT_OM					
307	Maintenance of general plant	935.0	0	INT_OM					
308	**Total Administrative and General Expenses**		118,072						
309	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		715,943						
310	**Adjustments, Depreciation and Amortization Expense**								
311	**Depreciation Expense**								
312	**Intangible Plant**								
313	Organization	301.0	0	INT_LABOR	-	-	-	-	-
314	Franchises & Consents	302.0	0	INT_TOTPLT	-	-	-	-	-
315	Misc. Intangible Plant	303.0	0	INT_TOTPLT	-	-	-	-	-
316	Subtotal - Intangible Plant		-						
317	**Manufactured Gas Production Plant**								
318	Land and Land Rights	304.0	0	-	-	-	-	-	-
319	Structures and Improvements	305.0	0	-	-	-	-	-	-
320	Liquefied Petroleum Gas Equipment	311.0	0	-	-	-	-	-	-
321	Producing Lands	325.1	0	-	-	-	-	-	-
322	Production Leaseholds	325.2	0	-	-	-	-	-	-
323	Rights-Of-Way	325.4	0	-	-	-	-	-	-
324	Other Lands	325.5	0	-	-	-	-	-	-
325	Field Measuring and Regulating Station Equipment	328.0	0	-	-	-	-	-	-
326	Other Structures	329.0	0	-	-	-	-	-	-
327	Producing Gas Wells - Well Construction	330.0	0	-	-	-	-	-	-
328	Producing Gas Wells - Well Equipment	331.0	0	-	-	-	-	-	-
329	Field Lines	332.0	0	-	-	-	-	-	-
330	Field Measuring and Regulating Station Equipment	334.0	0	-	-	-	-	-	-
331	Drilling and Cleaning Equipment	335.0	0	-	-	-	-	-	-
332	Other Equipment	337.0	0	-	-	-	-	-	-
333	Subtotal - Manufactured Gas Production Plant		-						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
334	**Natural Gas Underground Storage Plant**								
335	Land	350.1	0	-	-	-	-	-	-
336	Rights-of-way	350.2	0	-	-	-	-	-	-
337	Structures and Improvements	351.0	0	-	-	-	-	-	-
338	Well Construction	351.0	0	-	-	-	-	-	-
339	Storage leaseholds and rights	352.1	0	-	-	-	-	-	-
340	Reservoirs	352.2	0	-	-	-	-	-	-
341	Nonrecoverable natural gas	352.3	0	-	-	-	-	-	-
342	Lines	353.0	0	-	-	-	-	-	-
343	Compressor Station Equipment	354.0	0	-	-	-	-	-	-
344	Measuring and Regulating Equipment	355.0	0	-	-	-	-	-	-
345	Purification Equipment	356.0	0	-	-	-	-	-	-
346	Other Equipment	357.0	0	-	-	-	-	-	-
347	ARO for Natural Gas Underground Storage Plant	358.0	0	-	-	-	-	-	-
348	Subtotal - Natural Gas Underground Storage Plant		-						
349	**Transmission plant**								
350	Land and Land Rights	365.1	0	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
351	Rights-of-Way	365.2	11	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
352	Structures and improvements	366.0	0	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
353	Mains	367.0	399	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
354	Compressor station equipment	368.0	0	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
355	Measuring and regulating station equipment	369.0	87	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
356	Communication equipment	370.0	77	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
357	Other equipment	371.0	5	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
358	Testing Equipment	371.1	0	-	TRANSMISSION	DEMAND	AVG_EXCESS_Excl XD	-	-
359	Subtotal - Transmission plant		579						
360	**Distribution Plant**								
361	Land and land rights	374.0	43	INT_MAINS	-	-	-	-	-
362	Structures and improvements	375.0	144	INT_MAINS	-	-	-	-	-
363	Mains - Small	376.0	18,275	-	DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD	-	-
364	Mains - Large	376.0	30,741	-	DISTRIBUTION	DEMAND	AVG_EXCESS_Excl XD	-	-
365	Mains - Direct	376.0	2,379	-	DISTRIBUTION	DEMAND	XD_Direct	-	-
366	Compressor station equipment	377.0	0	-	-	-	-	-	-
367	Measuring and regulating station equipment—general	378.0	6,275	INT_MAINS	-	-	-	-	-
368	Measuring and regulating station equipment—city gate check stations	379.0	2,234	INT_MAINS	-	-	-	-	-
369	Services	380.0	51,721	-	DISTRIBUTION	CUSTOMER	-	-	SVCS_380
370	Meters	381.0	7,851	-	DISTRIBUTION	CUSTOMER	-	-	MTRS_381
371	Meter installations	382.0	3,709	-	DISTRIBUTION	CUSTOMER	-	-	MTRS_381
372	House regulators	383.0	206	-	DISTRIBUTION	CUSTOMER	-	-	MTRS_383
373	House regulatory installations	384.0	319	-	DISTRIBUTION	CUSTOMER	-	-	MTRS_383
374	Industrial measuring and regulating station equipment	385.0	798	-	DISTRIBUTION	CUSTOMER	-	-	MTRS_381
375	Other property	386.0	27	-	DISTRIBUTION	CUSTOMER	-	-	SVCS_380
376	Other equipment	387.0	89	INT_DISTEXP	-	-	-	-	-
377	Other equipment	387.1	0	INT_DISTEXP	-	-	-	-	-
378	Asset retirement costs for distribution plant	388.0	0	-	-	-	-	-	-
379	Subtotal - Distribution Plant		124,811						

UGI Utilities Inc. - Gas Division
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
380	**General Plant**								
381	Land and Land Rights	389.0	0	INT_OM	-	-	-	-	-
382	Structures and Improvements	390.0	8,959	INT_OM	-	-	-	-	-
383	Reading Service Center - Common Allocated	390.1	0	INT_OM	-	-	-	-	-
384	Structures and Improvements - Common Allocated	390.2	0	INT_OM	-	-	-	-	-
385	Office Furniture and Equipment	391.0	26,357	INT_OM	-	-	-	-	-
386	Office Furniture and Equip. - CIS	391.1	0	INT_OM	-	-	-	-	-
387	Office Furniture and Equip. - System Development Costs	391.2	0	INT_OM	-	-	-	-	-
388	Office Furniture and Equip. - System Development Costs	391.4	0	INT_OM	-	-	-	-	-
389	Transportation Equipment	392.0	8,288	INT_OM	-	-	-	-	-
390	Stores Equipment	393.0	1	INT_OM	-	-	-	-	-
391	Tools, Shop, and Garage Equipment	394.0	2,360	INT_OM	-	-	-	-	-
392	Laboratory Equipment	395.0	22	INT_OM	-	-	-	-	-
393	Power Operated Equipment	396.0	833	INT_OM	-	-	-	-	-
394	Communication Equipment	397.0	264	INT_OM	-	-	-	-	-
395	Misc. Equipment	398.0	86	INT_OM	-	-	-	-	-
396	Other Intangible Property	399.0	0	-	-	-	-	-	-
397	ARO for General Plant	399.1	0	-	-	-	-	-	-
398	Subtotal - General Plant		47,170						
399	**Total - Depreciation Expense**		172,559						
400	**Amortization Expense**								
401	Amortization of Net Salvage	404.1	9,703	INT_OM					
402	Subtotal - Amortization Expense		9,703						
403	**Adjustments**								
404	Amount Charged to Clearing Accounts		(11,745)	INT_OM					
405	Subtotal - Adjustments		(11,745)						
406	**Total Adjustments, Depreciation and Amortization Expense**		170,518						
407	**Taxes**								
408	**Taxes Other Than Income Taxes**								
409	PURTA & Property Taxes	408.1	1,420	INT_TOTPLT					
410	Taxes Other Than Income Taxes - Payroll	408.1	6,573	INT_LABOR					
411	Taxes Other Than Income Taxes - Excise	408.1	0						
412	Public Utility Assessment	408.1	6,006	INT_RATEBASE					
413	PA Local Use and Miscellaneous	408.1	1,250	INT_RATEBASE					
414	Miscellaneous Taxes	408.1	0	INT_TOTPLT					
415	Subtotal - Taxes Other Than Income Taxes		15,249						
416	**Income Taxes**								
417	Income Taxes - federal taxes utility operating income	409.1	41,256	INT_RATEBASE					
418	Income Taxes - State	409.1	8,900	INT_RATEBASE					
419	Provisions for deferred income taxes, utility operating income	410.1	0						
420	Provision for deferred income taxes—credit, utility operating income	411.1	0						
421	Investment Tax credit Adj.	411.4	0						
422	Subtotal - Income Taxes		50,156						
423	**Total Taxes**		65,405						

UGI Utilities Inc. - Gas Division
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
424	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
425	**Test Year Expenses at Current Rates**		951,866						
426	**Return on Rate Base**		354,187	INT_RATEBASE					
427	**Gross Up Items**								
428	Gross-up Federal Income Tax		18,972	INT_RATEBASE					
429	Gross-up State Utility Tax		7,314	INT_RATEBASE					
430	Gross-up Bad Debts		1,712		CUSTOMER	CUSTOMER			Uncollectibles
431	Gross-up Annual Filing Fee		0						
432	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**1,334,051**						
433	**INTERNAL ALLOCATION FACTORS**								
434	INT_TOTPLT		6,675,785						
435	INT_RATEBASE		4,319,351	15					
436	INT_OM		192,898	12					
437	INT_LABOR		46,421	13					
438	INT_REV_REQ		1,334,051						
439	INT_DISTEXP	871-879	47,945	10					
440	INT_DMAINT	886-893	28,936	11					
441	INT_MAINSXSML		2,055,921	17					
442	INT_MAINS		3,190,354	18					
443	*last line for internals*								

UGI Utilities Inc. - Gas Division
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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor Revenue/Margin Allocation Factor	Functional Allocation Factor Revenue Category	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
444	**Operating Revenue**								
445	Residential Sales	480.0	496,238	Revenues	Sales Revenue				
446	Commercial and industrial sales	481.0	198,491	Revenues	Sales Revenue				
447	Lg Transport/Other, Interruptible Sales	489.0	120,850	Revenues	Sales Revenue				
448	Residential Sales - GCR	480.GCR	298,400	GCR	Gas Cost Revenue				
449	Commercial and industrial sales - GCR	481.GCR	106,572	GCR	Gas Cost Revenue				
450	Lg Transport/Other, Interruptible Sales - GCR	489.3	0	GCR	Gas Cost Revenue				
451	Forfeited Discounts	487.0	6,337	Penalty Revenue	Other Revenues				
452	Miscellaneous service Revenue	488.0	2,142	INT_REV_REQ	Other Revenues				
453	Miscellaneous service Revenue - Reconnection Fees	488.0	0	Reconnect	Other Revenues				
454	Revenues from transportation of gas of others XD	489.3	1,036	XD_Direct	Other Revenues				
455	Rent from Gas Properties	493.0	215	INT_TOTPLT	Other Revenues				
456	Rent from Gas Properties	493.XD	2,077	XD_Direct	Other Revenues				
457	Other gas revenues	495.0	2,324	INT_REV_REQ	Other Revenues				
458	**Total Operating Revenue**		1,234,682						
459	**NET INCOME AT CURRENT RATES**		282,817						
460	**EARNINGS (DEFICIENCY)/SURPLUS**		(71,370)						
461	**REQUIRED INCOME INCREASE/(DECREASE)**		71,370						
462	**REVENUE GROSS-UP**		27,999						
463	**REQUIRED REVENUE INCREASE/(DECREASE)**		99,369						

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
Schedule 5 External Allocation Factors
FPFTY ending September 30, 2027

Line No	Allocator Code	Description	Classifier	Total	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
		CUSTOMER EXTERNAL ALLOCATORS								
1	**CUST**		CUS	100.00%	89.81%	9.87%	0.18%	0.09%	0.01%	0.04%
		Proforma Customer Count		706,232	634,252	69,690	1,305	638	54	293
2	**MTRS_381**		CUS	100.00%	45.37%	43.10%	4.84%	4.15%	0.79%	1.75%
		Cost of meters by class included in Accounts 381 and 385, Meters and M&R Equipment		204,440,309	92,757,900	88,107,949	9,894,911	8,481,363	1,616,403	3,581,784
3	**MTRS_383**		CUS	100.00%	88.18%	11.82%	0.00%	0.00%	0.00%	0.00%
		Number of weighted house regulators for customers served. Applicable to Rates R and N only		703,942	634,252	69,690				
		Relative Weighting Factor			1.00	1.22				
		Weighted Customers		719,274	634,252	85,022				
4	**MTRS_385**		CUS	100.00%	0.00%	0.00%	41.97%	35.98%	6.86%	15.19%
		Cost of meters by class included in Accounts 381 and 385, Meters and M&R Equipment. Not applicable to Rates R and N.		23,574,459	-	-	9,894,911	8,481,363	1,616,403	3,581,784
5	**SVCS_380**		CUS	100.00%	87.50%	11.72%	0.41%	0.26%	0.03%	0.10%
		Cost of services by class included in Account 380, Service Lines		1,647,771,953	1,441,766,561	193,073,405	6,676,398	4,210,666	434,211	1,610,711
6	**SALES_EXP_R/N**		CUS	100.00%	90.10%	9.90%	0.00%	0.00%	0.00%	0.00%
		Sales R, N only		703,942	634,252	69,690	0	0	0	0
7	**XD_Direct**		CUS	100%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
		Direct assignment to Rate XD Firm		54					54	
8	**Uncollectibles**		CUS	100.00%	93.57%	6.25%	0.03%	0.11%	0.00%	0.05%
		History of net write-offs by class (3-year average)		19,911,098	18,630,339	1,244,401	5,377	21,080	-	9,900
9	**Penalty Revenue**		CUS	100.00%	61.42%	28.53%	2.45%	3.87%	2.61%	1.12%
		Historical analysis of penalty revenue (Forfeited Discounts) by class		5,458,887	3,352,909	1,557,487	133,695	211,055	142,444	61,298
10	**Customer Deposits**		CUS	100.00%	50.97%	45.75%	1.30%	1.17%	0.62%	0.20%
		Factors are based on a historical analysis of customer deposits by class.		24,474,332	12,474,540	11,195,883	318,886	286,256	150,896	47,870

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
Schedule 5 External Allocation Factors
FPFTY ending September 30, 2027

Line No	Allocator Code	Description	Classifier	Total	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
11	**DIR_910.10**		CUS	100.00%	82.00%	6.58%	3.31%	8.12%	0.00%	0.00%
		Direct assignment of Energy Efficiency and Conservation Program expenses		12,026	9,861	791	398	976		
12	**R_Direct**		CUS	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Residential Direct		634,252	634,252					
13	**Reconnect**		CUS	100.00%	97.97%	2.03%	0.00%	0.00%	0.00%	0.00%
		Reconnection Fees based on historical data		1,711,050	1,676,349	34,700	0	0	0	0
		COMMODITY and REVENUE ALLOCATORS								
14	**TOTVOL**		COM	100.00%	14.89%	8.85%	2.61%	8.06%	61.27%	4.32%
		Total Volume - Forecasted Billing Determinants		339,204,231	50,491,037	30,008,036	8,868,042	27,341,950	207,826,615	14,668,550
15	**Avg. PGC Volumes**		COM	100.00%	73.71%	26.29%	0.00%	0.00%	0.00%	0.00%
		Average daily Purchased Gas Cost (PGC) volumes		164,540	121,275	43,265	-	-	-	-
16	**Avg. PGC_Choice Volumes**		COM	100.00%	62.72%	37.28%	0.00%	0.00%	0.00%	0.00%
		Average daily PGC & Choice volumes		220,546	138,332	82,214	-	-	-	-
17	**Avg. Daily Throughput**		COM	100.00%	14.89%	8.85%	2.61%	8.06%	61.27%	4.32%
		Average daily throughput volumes		929,327	138,332	82,214	24,296	74,909	569,388	40,188
18	**REVENUES**		REV	100.00%	60.83%	19.93%	4.42%	7.21%	4.80%	2.81%
		Revenue excl GCR		$ 815,249,115	$ 495,907,854	$ 162,481,380	$ 36,009,619	$ 58,767,849	$ 39,138,908	$ 22,943,504
19	**GCR**		REV	100.00%	73.71%	26.29%	0.00%	0.00%	0.00%	0.00%
		Gas Cost Revenue (GCR)		$ 405,302,162	$ 298,730,133	$ 106,572,029	$ -	$ -	$ -	$ -
		DEMAND ALLOCATORS								
20	**PEAKDAY_EXCESS**		DEM	100.00%	41.67%	29.80%	4.86%	4.05%	19.62%	0.00%
		Peak day excess demand, excluding interruptible		1,304,533	543,553	388,761	63,375	52,846	255,998	-
21	**PEAKDAY_EXCESS_Excl XD**		DEM	100.00%	51.84%	37.08%	6.04%	5.04%	0.00%	0.00%
		Peak day excess demand, excluding interruptible and XD Firm		1,048,535	543,553	388,761	63,375	52,846	-	-
22	**AVG_EXCESS_Excl XD**		DEM	100.00%	46.85%	31.57%	6.41%	11.67%	0.00%	3.50%
		Weighting of average daily volumes and peak day excess demand, excluding XD Firm		1.0000	0.4685	0.3157	0.0641	0.1167	-	0.0350
23	**AVG_EXCESS**		DEM	100.00%	30.32%	20.92%	3.91%	5.75%	37.26%	1.83%
		Weighting of average daily volumes and peak day excess demand		1.0000	0.3032	0.2092	0.0391	0.0575	0.3726	0.0183

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 6 - Internal Allocation Factors

Line No.	Category Description	Total System	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
1	**Allocation Factor Basis**							
2	0	-	-	-	-	-	-	-
3	0	-	-	-	-	-	-	-
4	0	-	-	-	-	-	-	-
5	0	-	-	-	-	-	-	-
6	0	-	-	-	-	-	-	-
7	0	-	-	-	-	-	-	-
8	0	-	-	-	-	-	-	-
9	INT_TOTPLT	6,675,785	4,030,498	1,590,731	269,318	453,588	193,341	138,311
10	INT_RATEBASE	4,319,351	2,586,349	1,029,313	177,720	303,428	130,366	92,175
11	0	-	-	-	-	-	-	-
12	0	-	-	-	-	-	-	-
13	0	-	-	-	-	-	-	-
14	INT_OM	192,898	140,171	27,963	6,126	8,949	7,044	2,647
15	0	-	-	-	-	-	-	-
16	0	-	-	-	-	-	-	-
17	0	-	-	-	-	-	-	-
18	0	-	-	-	-	-	-	-
19	INT_LABOR	46,421	29,590	9,191	2,217	2,636	1,849	938
20	INT_REV_REQ	1,334,051	902,768	295,286	34,477	55,315	29,410	16,796
21	0	-	-	-	-	-	-	-
22	INT_DISTEXP	40,881	24,234	8,811	1,461	2,493	3,124	758
23	INT_DMAINT	28,936	11,083	7,166	3,116	4,013	2,175	1,383
24	INT_MAINSXSML	2,055,921	894,004	602,451	122,286	222,747	147,691	66,743
25	INT_MAINS	3,190,354	1,425,484	960,605	194,984	355,169	147,691	106,422

UGI Utilities Inc. - Gas Division
Gas Class Cost of Service Study
FPFTY ending September 30, 2027 ($ in Thousands)
Schedule 6 - Internal Allocation Factors

Line No.	Category Description		Total System	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Rate IS
23	**Allocation Factor %**								
26		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
27		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
28		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
29		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
30		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
31		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
32		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
33	INT_TOTPLT		100.0%	60.4%	23.8%	4.0%	6.8%	2.9%	2.1%
34	INT_RATEBASE		100.0%	59.9%	23.8%	4.1%	7.0%	3.0%	2.1%
35		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
36		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
37		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
38	INT_OM		100.0%	72.7%	14.5%	3.2%	4.6%	3.7%	1.4%
39		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
40		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
41		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
42		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
43	INT_LABOR		100.0%	63.7%	19.8%	4.8%	5.7%	4.0%	2.0%
44	INT_REV_REQ		100.0%	67.7%	22.1%	2.6%	4.1%	2.2%	1.3%
45		0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
46	INT_DISTEXP		100.0%	59.3%	21.6%	3.6%	6.1%	7.6%	1.9%
			100.0%	38.3%	24.8%	10.8%	13.9%	7.5%	4.8%

BOOK X

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT F

CURRENT TARIFFS
UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI GAS EXHIBIT F – CURRENT TARIFF

GAS SERVICE TARIFF - PA P.U.C. NO. 7

UGI UTILITIES, INC. – GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Service and Choice Aggregation Service

in the

Territory Described Herein

Issued: November 26, 2025

Effective for service rendered on and after December 1, 2025. Issued in accordance with the Commission's Ordered entered September 25, 2025 at Docket No. R-2025-3054938.

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes changes, increases and decreases to existing rates (see Page 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Rider B – Purchased Gas Costs, Page 52
- The Annual C-Factor has decreased.
- The Annual E-Factor has increased.
- The Total Purchased Gas Cost rate has increased.

Section 15, Price to Compare, Page 57
- The Annual C-Factor has decreased.
- The Annual E-Factor has increased.
- The Merchant Function Charge has increased.
- The Price to Compare Charge has increased.

Rider F – Universal Service Program Rider, Page 58
- The Universal Service Program Rider rate has increased.

Rider G – Energy Efficiency and Conservation Rider, Pages 60-61.
- The Energy Efficiency and Conservation Rider has been updated to include cost recovery for expenses related to the development and implementation of Phase II of the Energy Efficiency and Conservation Plan approved by the Pennsylvania Public Utility Commission by Order entered July 24, 2025 at Docket No. M-2024-3048418.
- The Energy Efficiency and Conservation Rider rate has increased for Rate Schedules R/RT and LFD and decreased for Rate Schedules N/NT and DS.

Rider J – Gas Delivery Enhancement Rider, Page 67
- The Gas Delivery Enhancement Rider rate has decreased.

Section 22, General Terms for Delivery Service for Rates DS, LFD, XD, and IS, Page 75
- The retainage rate has increased.

Rate MBS, Monthly Balancing Service, Page 98(a)
- Rates DS/IS, LFD and XD have increased.

UGI Gas – Choice Supplier Tariff No. 7S

Cover Page, UGI Utilities, Inc. – Gas Division - Gas Choice Supplier Tariff
- Issuance and effective dates are updated.

Section 5.1, Operational Requirements, Page 116
- The retainage rate has increased.

Section 7.3, - Nomination Procedure, Page 118
- Peak Day allocation percentages are updated.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Rule 19, Rider I, Distribution System Improvement Charge, Page 63.
- The rate was reset to 0.00% and reference to prior rate case docket and Commission Order was removed.

Rule 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, Pages 76-77 and 79-81.
- All references to Gas Daily have been replaced with DPP.
- All references to "index" have been replaced by "Reference Price".
- Section 22.6 was updated to include references to Rate XD.

Rate R – General Service – Residential, Page 85.
- The Customer Charge and Distribution Charge have been increased.
- References to outdated Distribution Charge step increases removed.

Rate RT – General Service – Residential Transportation, Page 86.
- The Customer Charge and Distribution Charge have been increased.
- References to outdated Distribution Charge step increases removed.

Rate GL – General Service – Gas Light Service, Page 88.
- The Distribution Charge has been increased.
- References to outdated Distribution Charge step increases removed.

Rate N – General Service – Non-Residential, Page 89.
- The Customer Charge and the Distribution Charge have been increased.
- References to outdated Distribution Charge step increases removed.

Rate NT – General Service – Non-Residential Transportation, Page 90.
- The Customer Charge and the Distribution Charge have been increased.
- References to outdated Distribution Charge step increases removed.

Rate DS – Delivery Service, Page 94.
- The Customer Charge has been increased.
- The Maximum Distribution Charge has been increased and reflects a unified rate.
- References to outdated Distribution Charge step increases removed.

Rate MBS – Monthly Balancing Service, Page 98(a).
- The Rate MBS has been recalculated and increased.

Rate LFD – Large Firm Delivery Service, Pages 100-101.
- The Maximum Demand Charge has been increased.
- The Maximum Distribution Charge has been increased and outdated references have been removed.
- Unauthorized Overrun rate has been increased and additional clarifying language added.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Rate XD – Extended Large Firm Delivery Service, Pages 103-104.

- Language added for Capacity Charges, if applicable.
- The Maximum Average Delivery Charge has been increased and outdated references have been removed.
- Unauthorized Overrun rate has been increased and additional clarifying language added.

Rate IS – Interruptible Service, Page 108-110.

- Language added related to Manual Interruptible Customers' ability to manually transfer fuel source of its interruptible equipment.
- Consumption capability of a Manual Interruptible Customer was changed from an off-peak period to annual period.
- Minimum annual bill language was consolidated. Separate provisions for Automatic Temperature Control (ATC) and Manual Interruptible (MI) customers were removed.
- Language added to clarify pricing in Section 22.4 as it relates to Unauthorized Overrun charges.

Choice Supplier Tariff

Cover Page

- Updated for Supplement Number and Issue and Effective dates.

Rule 4, Choice Supplier Obligations, Page 115.

- Subsection 4.12 – The residential and commercial Purchase of Receivable rates have been updated as a result of the change to the Merchant Function Charge.

Rule 7, Nomination Procedure, Page 119.

- Reference to Platt's Gas Daily updated to reference DPP.
- Reference to Platt's Gas Daily Price Guide ("Inside FERC") updated to reference MPP.
- All references to "Index" have been replaced by "Reference Price".

Rule 10, Rate AG – Aggregation Service, Page 127.

- Reference to Platt's Gas Daily updated to reference DPP.

Rule 11, Aggregation Agreement for Rate Schedules RT and NT (Pro Forma), Pages 129-138.

- Changes and additions made to Article I. Definitions. Language added to clarify that the Nomination Procedure is available on UGI's Energy Management Website. New definitions added for Choice Aggregator, Choice Broker, and Choice Natural Gas Supplier/Licensed Supplier. Definitions were renumbered and Article number added.
- Subsections in Articles III and IV renumbered to include the Article number.
- Subsection 12.6 added to Article XII. Miscellaneous.
- Information shown on the various pages have shifted as a result of the above changes in addition to line spacing changes made for further formatting consistency. As a result of these pagination changes, there are new intentionally blank pages.

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(C) Indicates Change

Description of Territory (C)

ADAMS COUNTY

Townships

Cumberland	Freedom

ARMSTRONG COUNTY

City

Parker

BEDFORD COUNTY

Boroughs

Bedford	Everett

Townships

Bedford	Colerain	Monroe
Napier	Snake Spring Valley	West Providence

BERKS COUNTY

City

Reading

Boroughs

Adamstown (part)	Bally	Birdsboro
Boyertown	Centerpoint	Fleetwood
Hamburg	Kenhorst	Kutztown
Laureldale	Leesport	Lyons
Mohnton	Mt. Penn	New Morgan
Robesonia	St. Lawrence	Shillington
Shoemakersville	Sinking Spring	Topton
Wernersville	West Reading	Womelsdorf
Wyomissing	Wyomissing Hills	

Townships

Alsace	Amity	Bern
Caernarvon	Centre	Colebrookdale
Cumru	Douglass	Exeter
Heidelberg	Hereford	Jefferson

(C) Indicates Change

Description of Territory - Continued **(C)**

Longswamp	Lower Alsace	Lower Heidelberg
Maiden Creek	Marion	Maxatawny
Muhlenberg	Ontelaunee	Perry
Richmond	Robeson	Rockland
Ruscombmanor	South Heidelberg	Spring
Tilden	Union	Washington
Windsor		

BLAIR COUNTY

Boroughs

Martinsburg	Roaring Spring

Townships

Huston	North Woodbury	Taylor
Woodbury		

BRADFORD COUNTY

Boroughs

Alba	Burlington	Canton
Sylvania	Troy	

Townships

Armenia	Burlington	Canton
Columbia	Granville	LeRoy
Ridgebury	Smithfield	South Creek
Springfield	Troy	Ulster
Wells	West Burlington	

BUCKS COUNTY

Boroughs

Perkasie	Quakertown	Richlandtown
Riegelsville	Sellersville	Silverdale
Trumbauersville		

Townships

Durham	East Rockhill	Haycock
Hilltown	Milford	Nockamixon
Richland	Springfield	West Rockhill

(C) Indicates Change

Description of Territory - Continued (C)

CARBON COUNTY

Boroughs

Bowmanstown	East Side	Jim Thorpe
Lehighton	Palmerton	Weissport

Townships

Banks	East Penn	Kidder
Lower Towamensing	Mahoning (part)	Packer

CENTRE COUNTY

Boroughs

Philipsburg	South Philipsburg

Township

Rush

CHESTER COUNTY

Borough

Oxford

Townships

East Coventry (part)	East Nottingham	Elk
Honey Brook (part)	Lower Oxford	North Coventry (part)
Upper Oxford	West Nottingham	

CLARION COUNTY

Boroughs

Callensburg	Silgo

Townships

Ashland	Beaver	Clarion
Elk	Farmington	Highland
Knox	Licking	Limestone
Millcreek	Monroe	Paint
Perry	Piney	Richland
Salem	Toby	Washington

(C) Indicates Change

Description of Territory – Continued **(C)**

CLEARFIELD COUNTY

Boroughs

Chester Hill	Clearfield and Environs	Curwensville
Wallaceton		

Townships

Boggs	Bradford	Decatur
Knox	Lawrence	Morris
Pike		

CLINTON COUNTY

City

Lock Haven

Boroughs

Avis	Beech Creek	Flemington
Mill Hall	Renovo	South Renovo

Townships

Allison	Bald Eagle	Beech Creek (part)
Castanea	Chapman	Crawford
Dunnstable	Gallagher	Grugan
Noyes	Pine Creek	Wayne
Woodward		

COLUMBIA COUNTY

Boroughs

Berwick	Briar Creek	Centralia

Town

Bloomsburg

Townships

Briar Creek	Conyngham	Hemlock
Mifflin	Montour	Scott
South Centre		

(C) Indicates Change

Description of Territory - Continued **(C)**

CUMBERLAND COUNTY

Boroughs

Camp Hill	Carlisle	Lemoyne
Mechanicsburg	Mt. Holly Springs	New Cumberland
Shippensburg	Shiremanstown	West Fairview
Wormleysburg		

Townships

Dickinson	East Pennsboro	Hampden
Lower Allen	Middlesex	Monroe
North Middleton	Shippensburg	Silver Spring
Southampton	South Middleton	Upper Allen

DAUPHIN COUNTY

City

Harrisburg

Boroughs

Dauphin	Highspire	Hummelstown
Middletown	Paxtang	Penbrook
Royalton	Steelton	

Townships

Conewago	Derry (including Hershey)	East Hanover
Jackson	Jefferson	Lykens
Londonderry	Lower Paxton	Lower Swatara
Middle Paxton	Rush	South Hanover
Susquehanna	Swatara	West Hanover
Williams		

FOREST COUNTY

Borough

Tionesta

Townships

Barnett	Green	Harmony
Jenks	Tionesta	

(C) Indicates Change

Description of Territory – Continued **(C)**

FRANKLIN COUNTY

Boroughs

Orrstown	Shippensburg	Waynesboro

Townships

Greene (part)	Guilford (part)	Hamilton (part)
Letterkenny (Army Depot)	Southampton	Washington

FULTON COUNTY

Borough

McConnellsburg

Townships

Ayr (part)	Todd

HUNTINGDON COUNTY

Boroughs

Huntingdon	Mapleton	Mill Creek
Mount Union		

Townships

Brady	Henderson	Juniata
Oneida	Shirley	Smithfield
Union	Walker	

JEFFERSON COUNTY

Borough

Summerville

Township

Barnett

JUNIATA COUNTY

Townships

Tuscarora	Lack	Milford

(C) Indicates Change

Description of Territory – Continued **(C)**

LACKAWANNA COUNTY

Cities

Carbondale	Scranton

Boroughs

Archbald	Blakely	Clarks Green
Clarks Summit	Dalton	Dickson City
Dunmore	Jermyn	Jessup
Mayfield	Moosic	Moscow
Old Forge	Olyphant	Taylor
Throop	Vandling	

Townships

Abington	Benton	Carbondale
Clifton	Covington	Elmhurst
Fell	Glenburn	Greenfield
Jefferson	La Plume	Madison
Newton	North Abington	Ransom
Roaring Brook	Scott	South Abington
Spring Brook	West Abington	

LANCASTER COUNTY

City

Lancaster

Boroughs

Adamstown (part)	Akron	Columbia
Denver	East Petersburg	Elizabethtown
Ephrata	Lititz	Manheim
Marietta	Millersville	Mount Joy
Mountville	New Holland	Quarryville
Strasburg		

Townships

Brecknock	Caernarvon	Clay
Colerain	Conoy	Earl
East Earl	East Cocalico	East Donegal
East Drumore	East Hempfield	East Lampeter
Ephrata	Lancaster	Leacock

(C) Indicates Change

Description of Territory – Continued **(C)**

Little Britain	Manheim	Manor
Mount Joy	Paradise	Penn
Pequea	Rapho	Strasburg
Upper Leacock	Warwick	West Cocalico
West Donegal	West Earl	West Hempfield
West Lampeter		

LEBANON COUNTY

City

Lebanon

Boroughs

Cleona	Cornwall	Myerstown
Palmyra	Richland	

Townships

Annville	Bethel	Cold Spring
East Hanover	Jackson	Millcreek
North Annville	North Cornwall	North Lebanon
North Londonderry	South Annville	South Lebanon
South Londonderry	Swatara	Union
West Cornwall	West Lebanon	

LEHIGH COUNTY

Cities

Allentown	Bethlehem (part)

Boroughs

Alburtis	Catasauqua	Coopersburg
Coplay	Emmaus	Fountain Hill
Macungie	Slatington	

Townships

Hanover	Lower Macungie	North Whitehall
Salisbury	South Whitehall	Upper Macungie
Upper Milford	Upper Saucon	Washington
Weisenburg	Whitehall	

(C) Indicates Change

Description of Territory – Continued **(C)**

LUZERNE COUNTY

Cities

Hazleton	Nanticoke	Pittston
Wilkes-Barre		

Boroughs

Ashley	Avoca	Conyngham
Courtdale	Dallas	Dupont
Duryea	Edwardsville	Exeter
Freeland	Forty Fort	Harvey's Lake
Hughestown	Kingston	Laflin (part)
Larksville	Laurel Run	Luzerne
Nescopeck	New Columbus	Nuangola
Pittston	Plymouth	Pringle
Shickshinny	Swoyersville	Sugar Notch
Warrior Run	West Hazleton	West Pittston
West Wyoming	White Haven	Wyoming
Yatesville		

Townships

Bear Creek	Buck	Butler
Conyngham	Dallas	Dennison
Dorrance	Exeter	Fairmount
Fairview	Foster	Franklin
Hanover	Hazel	Hollenback (part)
Hunlock	Huntington	Jackson
Jenkins (part)	Kingston	Lake
Lehman	Nescopeck	Newport
Pittston	Plains	Plymouth
Rice	Ross	Salem
Slocum	Sugarloaf	Union
Wilkes-Barre	Wright	

LYCOMING COUNTY

City

Williamsport

Boroughs

Duboistown	Hughesville	Jersey Shore
Montgomery	Montoursville	Muncy

(C) Indicates Change

Description of Territory – Continued **(C)**

Picture Rocks	Salladsburg	South Williamsport

Townships

Anthony	Armstrong	Bastress
Brady	Clinton	Eldred
Fairfield	Franklin	Hepburn
Jackson	Jordan	Limestone
Loyalsock	Lycoming	McNett
Mifflin (part)	Millcreek	Moreland
Muncy	Muncy Creek	Nippennose
Old Lycoming	Penn (part)	Piatt
Porter	Shrewsbury (part)	Susquehanna
Upper Fairchield	Washington	Wolf (part)
Woodward		

MCKEAN COUNTY

Boroughs

Eldred	Mount Jewett	Port Allegany

Townships

Annin	Ceres	Eldred
Hamlin	Keating	Liberty
Norwich	Otto	Sergeant

MIFFLIN COUNTY

Boroughs

Burnham	Juniata Terrace	Lewistown
McVeytown		

Townships

Armagh	Bratton	Brown
Decatur	Derry	Granville
Menno	Union	

MONROE COUNTY

Boroughs

Delaware Water Gap	East Stroudsburg	Mount Pocono
Stroudsburg	White Haven	

(C) Indicates Change

Description of Territory – Continued **(C)**

Townships

Chestnuthill	Coolbaugh	Eldred
Hamilton	Middle Smithfield	Paradise
Pocono	Ross	Smithfield
Stroud	Tobyhanna	Tunkhannock

MONTGOMERY COUNTY

Townships

Douglas	New Hanover	Limerick (restricted)

MONTOUR COUNTY

Borough

Danville

Townships

Cooper	Liberty (part)	Limestone
Mahoning	Valley	

NORTHAMPTON COUNTY

Cities

Bethlehem (part)	Easton

Boroughs

Bangor	Bath	East Bangor
Freemansburg	Glendon	Hellertown
Nazareth	Northampton	North Catasauqua
Pen Argyl and Vicinity	Portland	Roseto
Stockertown	Tatamy	Walnutport
West Easton	Wilson	Wind Gap

Townships

Allen	Bethlehem	Bushkill
East Allen	Forks	Hanover
Lehigh	Lower Mount Bethel	Lower Nazareth
Lower Saucon	Palmer	Plainfield
Upper Mount Bethel	Upper Nazareth	Washington
Williams		

(C) Indicates Change

Description of Territory – Continued **(C)**

NORTHUMBERLAND COUNTY

Cities

Shamokin	Sunbury	

Boroughs

Kulpmont	Marion Heights	Milton
Mount Carmel	Northumberland	Riverside
Snydertown	Turbotville	Watsontown

Townships

Coal	Delaware	East Cameron
East Chillisquaque	Jordan	Lewis Twp.
Little Mahanoy	Lower Augusta	Mount Carmel
Point	Ralpho	Rockefeller
Shamokin	Turbot	Upper Augusta
Washington	West Cameron	West Chillisquaque
Zerbe		

PIKE COUNTY

Borough

Milford

Townships

Dingman	Lehman	Milford
Westfall		

POTTER COUNTY

Boroughs

Austin	Bingham	Coudersport
Galeton	Hebron	Oswayo
Shinglehouse	Ulysses	

Townships

Abbott	Allegany	Clara
Eulalia	Genesee	Harrison
Hector	Hebron	Homer
Keating	Oswayo	Pike

(C) Indicates Change

Description of Territory – Continued **(C)**

Pleasant Valley	Portage	Roulette
Sharon	Summit	Sweden
Sylvania	Ulysses	West Branch
Wharton		

SCHUYLKILL COUNTY

City

Pottsville

Boroughs

Ashland	Auburn	Cressona
Deer Lake	Frackville	Gilberton
Girardville	Gordon	Landingville
McAdoo	Mechanicsville	Middleport
Minersville	Mount Carbon	New Philadelphia
Orwigsburg	Palo Alto	Port Carbon
Port Clinton	Ringtown	St. Clair
Schuylkill Haven		

Townships

Blythe	Branch	Butler
Cass	East Union	East Norwegian
Foster	Hubley	Kline
Mahanoy (part)	New Castle	North Manheim
Norweigan	Ryan	South Manheim
Union	Upper Mahantongo	West Brunswick
West Mahanoy		

SNYDER COUNTY

Boroughs

Selinsgrove	Shamokin Dam

Townships

Middlecreek	Monroe	Penn

SUSQUEHANNA COUNTY

Boroughs

Forest City	Uniondale

(C) Indicates Change

Description of Territory – Continued **(C)**

Townships

Auburn	Clifford	

TIOGA COUNTY

Boroughs

Blossburg	Elkland	Knoxville
Lawrenceville	Liberty	Mansfield
Roseville	Tioga	Wellsboro
Westfield		

Townships

Bloss	Brookfield	Charleston
Chatham	Clymer	Covington
Deerfield	Delmar	Duncan
Elkland	Farmington	Gaines
Hamilton	Jackson	Lawrence
Liberty	Middlebury	Nelson
Osceola	Putnam	Richmond
Rutland	Shippen	Sullivan
Tioga	Union	Ward
Westfield		

UNION COUNTY

Borough

Lewisburg

Townships

Buffalo (part)	East Buffalo (part)	Gregg
Kelly (part)	Lewis	Union (part)
West Buffalo (part)	White Deer	

VENANGO COUNTY

City

Oil City

Boroughs

Rouseville	Sugarcreek

(C) Indicates Change

Description of Territory – Continued **(C)**

Townships

Clinton	Cornplanter	Cranberry
Pinegrove	President	Richland
Rockland		

WAYNE COUNTY

Boroughs

Bethany	Hawley	Honesdale
Waymart		

Townships

Berlin	Canaan	Cherry Ridge
Clinton	Dyberry	Oregon
Palmyra	Paupack	Texas

WYOMING COUNTY

Boroughs

Factoryville	Laceyville	Meshoppen
Nicholson	Tunkhannock	

Townships

Braintrim	Clinton	Eaton
Exeter	Falls	Forkston
Lemon	Mehoopany	Meshoppen
Monroe	Nicholson	North Branch
Northmoreland	Noxen	Overfield
Tunkhannock	Washington	Windham

YORK COUNTY

Townships

Fairview	Newberry

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DEFINITIONS – GENERAL

Alternate Fuel:	Any fuel other than natural gas.
Applicant:	Any person, corporation or other entity that (i) desires from the Company natural gas or any other service provided for in this Tariff at a specific location, (ii) complies completely with all Company requirements for obtaining natural gas or any other service provided for in this Tariff, (iii) has filed and is awaiting Company approval of its application for service, and (iv) is not yet lawfully receiving from the Company any service provided for in this Tariff at such location.
Authorized Payment Agent:	An agent expressly authorized by Company to accept payments from Customers on behalf of Company.
Automated Meter Reading ("AMR"):	Metering using technologies that automatically read and collect data from metering devices and transfer that data to a central database for billing and other purposes and does not include a Remote Meter Reading Device. All meter readings by an AMR shall be deemed actual readings.
BTU (British Thermal Unit):	The amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. **(C)**
Ccf:	100 cubic feet of gas. This is a measure of gas usage.
CFH:	Cubic feet per hour.
CCFD:	One Hundred Cubic feet per day.
Chapter 56:	The PUC regulations that govern metering, billing and collections for residential gas and electricity service.
City Gate:	A point of interconnection between the Company's facilities and third party source of supply.
Combined Billing:	The aggregation of the billing determinants of two or more meters of the same Customer at the same location for billing purposes. This applies to only contiguous properties with the same billing/meter read date.
Consolidated Billing:	The aggregation of two or more Customer bills to one bill from different service locations or the same service location for ease of Customer receiving one bill for multiple service locations instead of receiving multiple bills. Each meter will be billed under the applicable Tariff rate and will not be considered combined billing. Customer will be required to pay Company to perform such transactions.
Commodity:	The gas delivered to a Customer during the billing month.
Company:	UGI Utilities, Inc. – Gas Division

(C) Indicates Change

DEFINITIONS – GENERAL (Continued)

Company: UGI Utilities, Inc. – Gas Division

Commercial Customer: A Customer who is not classified as an Industrial Customer or a Residential Customer.

Confirmed Low Income Customer: A Household for which UGI has information that would make it reasonably likely that the household has income at or below 150% Federal Poverty Level ("FPL"), consistent with the Commission's definition in 52 Pa. Code 62.2 and 69.262. Household information that fits this criteria includes: **(C)**

a. Self-certification;
b. Participation in any of the Company's income verified programs, including but not limited to CAP, Operation Share, or LIURP, where income is verified to be at or below 150% FPL; and/or
c. Receipt of LIHEAP funds in the prior 12 months.

Creditworthiness: An assessment of an Applicant's or Customer's ability to meet bill payment obligations for utility service.

Critical Day: Any day, determined by company in its sole discretion, when variations in supply or demand could jeopardize the safety or reliability of Company's Gas Service.

Customer: Any person, corporation or other entity lawfully in receipt of gas service, aggregation and balancing services or interconnection coordination services from the Company under this Tariff.

Customer Charge: A monthly charge.

Daily Flow Directive ("DFD"): An order issued by the Company to address system management, including actions necessary to comply with statutory directives and obligations. DFDs will be communicated to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, by facsimile, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. Customers and NGSs must provide the Company with a 24-hour contact for DFDs.

Daily Price Publication ("DPP"): The daily price reference guide published by S&P Platts (i.e., Gas Daily) or its successor (the "Reference Price"). In any event that the daily price reference guide published by S&P Platts or its successor expires, is terminated, or is otherwise unavailable to the Company, the Company shall use a commercially reasonable alternative published daily price guide Reference Price. If at any point the Reference Price locations change published name, expire, are discontinued from publication, are terminated, or are otherwise unavailable to the Company, the closest applicable alternative price location shall be used as the Reference Price location. **(C)**

(C) Indicates Change

DEFINITIONS – GENERAL (Continued)

Discontinuance of Service:	The cessation of service with the consent of Customer.
Distribution Charges:	Charges to recover the costs the Company incurs to provide the services necessary to deliver natural gas to a Customer from the point of receipt into the Company's distribution system.
Dth ("Dekatherm"):	A measure of the heat content value of gas. Gas usage is determined by multiplying the MCF used by the heat content value of the gas.
Extension Applicant:	Any person, corporation or other entity, whether or not currently receiving from the Company any service provided for in this Tariff, who desires from the Company an extension or expansion of facilities under Section 5 of this Tariff and who complies with all Company requirements for obtaining an extension or expansion of facilities as provided for in this Tariff.
Gas or Natural Gas:	A flammable gas meeting PUC heating value and purity requirements that may include natural gas, synthetic natural gas, propane, landfill gas and any and all natural gas substitutes.
Gas Service:	The furnishing of gas by the Company at the point of delivery regardless of whether the Customer makes any use of the gas.
Gas Supply or Commodity Charge:	Charges by an NGS or Supplier of Last Resort to recover the cost of procuring natural gas and delivering it to the Company's facilities for redelivery to Customers.
Industrial Customer:	A Customer engaged in the process which creates or changes raw materials or unfinished materials into another form or product.
Interruptible Service:	Natural gas services that can be temporarily discontinued under terms and conditions specified by Tariff or contract.
MCF:	1,000 cubic feet of gas. This is a measure of gas usage.
Monthly Price Publication ("MPP"):	The monthly price reference guide published by S&P Platts (i.e., Inside FERC Gas Market Report First of Month) or its successor(the "Reference Price"). In any event that the monthly price reference guide published by S&P Platts or its successor expires, is terminated, or is otherwise unavailable to the Company, the Company shall use a commercially reasonable alternative published monthly Reference Price guide. If at any point the Reference Price locations change published name, expire, are discontinued from publication, are terminated, or are otherwise unavailable to the Company, the closest applicable alternative price location shall be used as the Reference Price location. **(C)**

(C) Indicates Change

DEFINITIONS – GENERAL (Continued) **(C)**

Natural Gas Supplier ("NGS"):	Any person, corporation or other entity that has received a license from the PUC to supply natural gas supply services to Customers in the Company's service territory and that has met the additional criteria established by the Company to permit it to provide natural gas supply service to Customers.
Non-Critical Day:	Any day determined by Company not to be a Critical Day
Non-Residential Applicant:	An Applicant not classified as a Residential Applicant.
Non-Residential Customer:	A Customer not classified as a Residential Customer, including a Commercial Customer and an Industrial Customer.
Occupant:	A natural person who resides in the premises to which gas service is provided.
Operational Flow Order ("OFO"):	A directive issued by the Company that is reasonably necessary to alleviate conditions that threaten the operational integrity of the Company's system on a critical day, including actions necessary to comply with statutory directives and obligations. OFOs will be communicated as soon as reasonably practical to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, by facsimile, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. Customers and NGSs must provide the Company with a 24-hour contact for OFOs.
Point of Delivery:	The outlet of company facilities; usually the meter or regulator outlet.
Price to Compare:	The dollar amount charged by the Company, used by Customers to compare prices and potential savings with other Natural Gas Suppliers.
PUC:	The Pennsylvania Public Utility Commission.
Remote Meter Reading Device:	A device which by electrical impulse or otherwise transmits readings from a meter, usually located within a residence, to a more accessible location outside a residence. The term does not include AMR and devices that permit direct interrogation of the meter.

(C) Indicates Change

DEFINITIONS – GENERAL (Continued) **(C)**

Residential Applicant: An Applicant who is (1) a natural person at least 18 years of age not currently receiving service who applies for residential service, or (2) an adult Occupant whose name appears on the mortgage, deed or lease of the property for which the residential utility service is requested. The term shall not include (1) a Residential Customer who seeks to transfer service within the Company's service territory, or (2) a Residential Customer who, within 30 days after Termination or Discontinuance of Service, seeks to have service reconnected at the same location or transferred to another location within the Company's service territory.

Residential Customer: A Customer who is either (1) a natural person at least 18 years of age in whose name a residential account is listed and who is primarily responsible for payment of bills rendered for the service, or (2) any adult Occupant whose name appears on the mortgage, deed or lease of the property for which residential service is requested. A Residential Customer shall be further defined to include a Customer receiving the Company's gas service to a single-family dwelling or building, through one meter to four or fewer dwelling units in a multi-family dwelling, or premises used as a single family dwelling and for one or more business uses, provided the proprietor of the business resides in the single family dwelling, and the business uses less than fifty percent of the anticipated gas usage served through a single meter. Service will be supplied only where the Company's facilities are suitable to the service desired. A Residential Customer shall remain a Customer after Discontinuance of Service or Termination of Service until the final bill for service is past due. The term includes a person who, within 30 days after Termination or Discontinuance of Service, seeks to have service reconnected at the same location o transferred to another location within the Company's service territory.

Supplier of Last Resort: The Company or another entity that provides natural gas supply services to Customers that do not elect another supplier or choose to be served by the supplier of last resort, Customers that are refused service from another natural gas supplier, or Customers whose natural gas supplier fails to deliver the required gas supplies. Currently, the Company is the supplier of last resort for all Customers under the terms of this Tariff. Each Customer may only have one supplier of last resort with one exception: The Company shall be under no obligation and shall have no duty to serve as Supplier of Last Resort to any Rate DS, IS, LFD, or XD customers.

Tariff: The rates, rules, and regulations set forth herein, as may be amended, modified or superseded from time to time. The Tariff is on file with the PUC and available on the Company's website.

(C) Indicates Change

DEFINITIONS – GENERAL (Continued) **(C)**

Termination of Service:	The cessation of service, whether temporary or permanent, without the consent of Customer.
Unauthorized Use of Service:	Unreasonable interference or diversion of service, including meter tampering (any act which affects the proper registration of service through a meter), by-passing unmetered service that flows through a device connected between a service line and customer-owned facilities and unauthorized service restoral.
User Without Contract:	A natural person who takes or accepts gas service without the knowledge or approval of the Company, other than the Unauthorized Use of Service as defined above.

(C) Indicates Change

RULES AND REGULATIONS

1. THE GAS SERVICE TARIFF

1.1 Agreements. No agent or employee of the Company has authority to make any promise, agreement or representation not consistent with this Tariff.

1.2 Waiver of Rights. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to enforce any of the terms of this Tariff.

1.3 Filing and Posting. A copy of this Tariff is on file with the PUC and is available on Company's website at https://www.ugi.com/tariffs (C)

1.4 Application of Rates: The rates named in this Tariff are based upon supply to one Customer through one meter at the same or contiguous property. Each service to a different location and/or of a different rate classification shall be billed as a separate Customer. Customers who take service at two or more locations on the same or contiguous property under the same rate schedule may, by request, have their use of gas combined for billing purposes; Customers electing to take advantage of this rule shall pay the cost of all additional service connections required unless, in the Company's sole judgment, the Company's investment in such connections is warranted by the revenue anticipated from the service to be supplied. The Company will provide Customers with a written explanation regarding its analysis of the arrangement's economics. Customers may not pool together for purposes of qualifying for a rate schedule.

1.5 Liability and Legal Remedies: The Customer will indemnify, defend and hold harmless the Company against all claims, demands, costs or expenses for loss, damage, or injury to person or property in any manner either directly or indirectly connected with or growing out of the supply or use of gas service by the Customer at or on the Customer's side of the point of delivery. Neither the Company nor the Customer will be liable to each other for any act or omission caused either directly or indirectly by strikes, labor troubles, accidents, litigation, federal, state or municipal laws or interference, or other causes not a result of each party's own negligence or intentional misconduct.

(C) Indicates Change

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE

2.1 Application for Service. Every Applicant for Gas Service must apply through the Company. Non-Residential Applicants may be required to sign a contract for service consistent with this Tariff.

2.2 Right to Reject. The Company may limit the amount and character of service it will supply. It may reject applications where service is not available, or which might affect service to existing Customers, or for other good and sufficient reasons at the Company's sole discretion.

2.3 Facilities and System Access. Each Customer with a Daily Firm Requirement ("DFR"), Maximum Daily Quantity ("MDQ"), or peak usage capability of 1,000 MCF per day or greater shall provide the Company with the opportunity to review plans for the development of all gas facilities to the Customer's premises (including pipelines, mains, service lines and appurtenances), in order to assure safety and reliability, as follows: **(C)**

(a) If the Customer proposes to acquire, construct or contract for the use of service of gas facilities ("Customer gas facilities"), the Customer will provide advance notice to the Company in writing, at least sixty (60) days in advance of the earlier of the effective date of a contract or commencement date for construction of Customer gas facilities.

(b) The Customer agrees to submit all design and construction specifications and drawings to the Company in advance of construction, which demonstrate compliance with all applicable requirements as to gas main and service construction and pipeline safety. If the Company determines that Customer gas facilities will encroach upon or interconnect with Company facilities, serve common gas utilization equipment with Company facilities or are in the immediate vicinity of Company facilities such that the safety of Company facilities may be adversely affected thereby, the Company shall have the right to approve the design and location of such Customer gas facilities. The Company shall act upon its right to approve such Customer gas facilities within ninety (90) days after the later of submission of all design and construction specifications and drawings to the Company, or Customer notification required under Rule 2.3(a), provided however, if the Company fails to respond in writing within the ninety (90) day time period the Customer may move forward with its project. Customer gas facilities will be deemed to encroach upon the Company's facilities when they would interfere with or prevent the Company from accessing, maintaining or operating its facilities or when the Customer gas facilities would be configured or located in a manner that would cause safety or reliability concerns with respect to the Company's facilities.

(c) If the full sixty (60) day notice required in Rule 2.3(a) is not given by the Customer then the Customer shall be deemed to have granted the Company full authority to discontinue service upon discovery of any safety or reliability concerns. The Company will provide 24 hours' notice unless there are reliability or safety issues that must be addressed immediately. The Company shall not be liable for any costs or damages caused by such service discontinuance.

(C) Indicates Change

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE - Continued

2.4 Selection of Rate Schedules. When the characteristics of usage or service conditions of an Applicant or Customer are such that more than one rate schedule is available, the Applicant or Customer shall select the schedule to be applied. Upon request, the Company will assist to a reasonable extent in selecting the most advantageous schedule. For Customers changing schedules, the Company will bill the Customer under the selected rate beginning with the date of the next scheduled meter reading following notification of the selected rate. When service under a Demand Charge rate commences prior to the installation of equipment for determining the Customer's demand, the Customer's demand for billing purposes will be estimated by the Company.

2.5 Use of Gas. The use of gas shall only be for the purpose and in the places identified by the customer in applying for service. The gas supplied by the Company shall not be resold without the express written permission of the Company. In the event that the Customer uses the gas in an improper or unsafe manner, in violation of this Tariff or any applicable federal, state or municipal laws or codes, the Company may immediately terminate service as described in the Service Discontinuation and Termination section of this Tariff. In the event that any loss is sustained as a result of Customer's improper or illegal use of the gas, the Customer agrees to indemnify, defend and hold harmless Company. The Company will not supply gas for any additional equipment, or any increased usage for any Customer, unless request was filed with the Company prior to the connection or increased usage. The Company reserves the right to limit or discontinue Gas Service or charge Customer upgrade installation charges in order to provide additional Gas Service. Customer is responsible for any loss of Gas Service to other Customers caused by failure to register.

2.6 Distribution System Bypass. Unless otherwise provided by contract, if any Customer or potential Customer of the Company bypasses the Company for all or a portion of their Natural Gas Service needs then the Company thereafter shall have no obligation to serve or maintain the gas supply or physical capacity necessary to serve the Bypass portion of such Customer load, provided, however, that the Company will continue to serve the un-bypassed portion of a bypassing Customer's load consistent with the terms of any existing service agreement and will negotiate new service agreements to continue service so-long as the anticipated revenues justify any costs of providing the service. In addition, to the extent that such Customer returns from a total bypass, the Company shall serve such Customer as a new Customer and shall have the right to charge a negotiated rate for continued, subsequent or standby service that, at a maximum, is established solely by competitive market conditions, which shall reflect the costs of the Customer's alternatives.

2.7 Conditions Under Which Service Will Be Rendered From Transmission or Gathering Lines. The Company does not undertake or hold itself out to serve Customers from its transmission or gathering lines. Applications for service therefore may, at the election of the Company, be accepted where the lines are being operated in a manner which will permit gas to be served to the Applicant without interference with its operations. Applicants, if accepted by the Company, must agree to comply with the Rules and Regulations of the Company and more particularly the following rules applicable to this type of service:

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE - Continued

(a) Applicants agrees that service is only offered with the understanding that the Company's line from which gas is to be supplied is not permanent and that service to the Applicant is subject to temporary or absolute change or discontinuance at the sole discretion of the Company, which may at any time remove, repair, or change the use or manner of operating said line.

(b) Applicants agrees that the Company may at any time cancel service upon thirty (30) days' written notice to the Applicant and Applicant agrees that upon receipt of such notice of cancellation to promptly discontinue service within the said thirty (30) day period, and such cancellation and termination of service shall not be construed as an abandonment of service to such Customer within the meaning of the Pennsylvania Public Utility Code.

(c) The Applicant agrees to accept the gas at the varying pressures at which the line is operated from time to time and Applicant understands that such pressure is not governed by regulators but it is high and low and the Applicant expressly assumes the duty of regulating the flow of the pressure of gas delivered to him and he assumes all risks from variation in pressure, defects in pipe, connections and appliances, from the escape and leakage of gas, from the sticking of valves and regulators and from the burning of gas on his premises and from like causes incident to the use of gas.

(d) The Company shall not be liable for any deficiency in the supply of gas caused by the use of compressing stations, breakage of lines, variations in pressure, discontinuance of service or any other causes.

(e) The Company shall not be liable for any damage arising out of this agreement or the service supplied thereto.

(f) Service shall be at the sole risk of the Customer.

2.8 Government Identification to Establish Service. The Company will accept any current form of government-issued identification, including identification issued by a foreign government, to establish service. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT

3.1 Deposits for Non-Residential Accounts. A cash deposit may be required from a Non-Residential Applicant to secure payment of bills for regulated distribution service. In addition, the Company may require a deposit, letter of credit or other adequate assurance of payment, or any combination thereof, from a Non-Residential Customer if the Non-Residential Customer has been delinquent in payment of any bill in the preceding twelve (12) months or the Company otherwise has reasonable grounds to require security for payment of bills. The deposit shall not be more than the bill for regulated distribution service for the estimated usage for one average monthly billing period plus that for the highest billing period within the most recent twelve (12) months with a minimum fifty dollars ($50.00) deposit.

3.2 Additional Security from Large Volume Customers.

(a) Whether or not the Company could otherwise require security for payment, the Company may require a deposit, letter of credit, other adequate assurance of payment, or any combination thereof, to the extent the Customer seeks any combination of delivery or retail service for volumes in excess of 3,000 MCF per month. Such security may be established for an amount as determined by the Company.

(b) In addition, the Company may take one or more of the following actions:

(1) With the agreement of the Customer, reduce the meter reading and billing period to less than one month, require payment in no less than three calendar days from billing.

(2) Require payment by certified check or wire transfer; and

(3) Impose other procedures reasonably designed to reduce potential exposure to credit risk.

(c) The Company may, in its discretion, specify the manner in which security and payments shall be credited and applied to past due or current bills or to replenish security.

3.3 Deposits for Residential Accounts. The Company may require a cash deposit from a Residential Applicant or Residential Customer to secure payment of bills for regulated distribution service based upon the following:

(a) A Residential Applicant or Residential Customer whose service was terminated for any of the following reasons:

(1) Nonpayment of an undisputed delinquent account.

(2) Failure to complete payment of a deposit, providing a guarantee or establish credit.

(3) Failure to permit access to meters, service connections or other property of Company for the purposes of replacement, maintenance, repair, or meter reading.

(4) Unauthorized Use of Service on or about the affected dwelling.

(5) Failure to comply with the material terms of a payment arrangement.

(6) Fraud or material misrepresentation of identity for the purposes of obtaining utility service.

(7) Tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other Company equipment.

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT - Continued

(8) Violating tariff provisions on file with the PUC so as to endanger the safety of a person or the integrity of the Company's delivery system.

(b) Any Residential Applicant who is unable to establish creditworthiness to the satisfaction of Company through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that falls within the range of general industry practice and specifically assesses the risk of utility bill payment.

(c) A Residential Customer who fails to comply with the material terms or condition of a settlement or payment arrangement.

(d) A Residential Customer who has been delinquent in the payment of two (2) consecutive bills, or three (3) or more bills within the preceding twelve (12) months.

(e) The Company has established separate credit procedures and standards for Residential Applicants and Residential Customers who are victims with a protection from abuse order or for whom there is a court order from a court of competent jurisdiction in this Commonwealth, which provides clear evidence of domestic violence against the Residential Applicant or Residential Customer. These procedures shall be publicly posted on the Company's website and maintained on file in each of the business offices of the Company and made available, upon request, for inspection by members of the public.

(f) Effective November 1, 2025, the Company may not require a cash deposit from an applicant who is, based upon household income, confirmed to be eligible for a customer assistance program. An applicant is confirmed to be eligible for a customer assistance program by the Company if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the Company's customer assistance programs. For existing customers that already have monies paid against a security deposit and become enrolled in the Company's customer assistance programs, the Company will provide the customer a direct refund of the security deposit amount, along with applicable interest. The Company may apply the refund of the security deposit amount, with applicable interest, to the customer's account balance with the customer's informed consent. If checks providing a direct refund of the security deposit are returned as undeliverable, the Company will apply the amount as a bill credit, unless the customer contacts the Company with a corrected address. **(C)**

3.4. Amount of Deposit for Residential Accounts. For Residential Applicants, the amount of the cash deposit shall not be more than 1/6 of a Residential Applicant's estimated annual bill, with such estimated annual bill determined at the time the deposit is required. In lieu of a cash deposit from a Residential Applicant, the Company may accept a written third-party guaranty on behalf of the Residential Applicant, provided that the guarantor establishes credit with the Company under Section 3.3 and the terms of the written guaranty are approved in writing by the Company, with such approval not to be unreasonably withheld. For Residential Customers, the amount of the cash deposit shall not be more than the estimated charges for service based on the Residential Customer's prior consumption for the period equal to one average billing period plus one average month, not to exceed two (2) months. Deposit amounts for Residential Applicants and Residential Customers may include Natural Gas Supplier charges where such Supplier is a participant in the Company's Purchase of Receivables Program.

(C) Indicates Change

RULES AND REGULATIONS **(C)**

3. GUARANTEE OF PAYMENT – Continued

3.5 Payment Period for Deposits.

(a) Any Non-Residential Applicant seeking to establish service at a new or different service location or seeking to reconnect service at the same service location previously terminated or discontinued, shall pay the required deposit in full prior to the provision of service.

(b) Any Residential Applicant or Residential Customer seeking to establish service at a new or different location or seeking to reconnect service at the same service location previously terminated or discontinued shall pay the required deposit in full within 90 days. A Residential Applicant or Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the establishment or reconnection of service, within

25% of the required deposit to be billed by the Company 30 days after the establishment or reconnection of service and the remaining 25% billed 60 days after the establishment or reconnection of service. Nothing shall preclude the Residential Applicant or Residential Customer from electing to pay the deposit in full before or on the due date.

(c) Any Customer receiving service from the Company shall pay the required deposit in full on or before the due date. A Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the determination by the Company under Section 3.3(c) or (d) above that the deposit is required, with 25% to be billed by the Company 30 days after the determination and the remaining 25% billed 60 days after the determination.

3.6 Deposit Hold Period for Residential Accounts. A timely payment history is established for a Residential Customer when the Residential Customer has paid in full and on time for twelve (12) consecutive months. Company may hold a deposit on a Residential Customer's account until a timely payment history is established (the "Deposit Hold Period"). At the end of the Deposit Hold Period Company shall credit the deposit, plus accrued interest, to the Residential Customer's account. Deposits credited after the end of the Deposit Hold Period shall first be applied to any past due amounts. If service is terminated or discontinued before the end of the Deposit Hold Period, Company shall deduct any outstanding balance from the deposit and return any positive balance to the Residential Customer within sixty (60) days.

3.7 Refund Provision Non-Residential Customers. Deposits secured from Non-Residential Customers will be refunded when the Customer discontinues service and has no unpaid bills or at Company's sole discretion.

3.8 Adjustments. The amount of the deposit may be adjusted when there is a change in consumption that will significantly change the amount of the deposit as computed in Rule 3.1 and 3.4.

(C) Indicates Change

RULES AND REGULATIONS **(C)**

3. GUARANTEE OF PAYMENT - Continued

3.9 Interest on Deposits. Deposits from all Customers shall bear interest computed at the simple annual interest rate determined by the Secretary of Revenue for interest on underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as The Fiscal Code which will be credited annually to the Customer's deposit or account. The interest rate in effect when the deposit is required to be paid shall remain in effect until the later of the date the deposit is refunded or credited or December 31 of each year. On January 1 of each year, the new interest rate for that year will apply to the deposit. Deposits shall cease to bear interest upon termination or discontinuance of the service covered by the deposit.

3.10 Prior Debts.

(a) Non-Residential Accounts. As a condition of furnishing, transferring or reconnecting service to a Non-Residential Applicant or Non-Residential Customer, the Company may require payment of any outstanding balance on any account for which the Non-Residential Applicant or Non-Residential Customer is legally responsible.

(b) Residential Accounts. As a condition of furnishing, transferring or reconnecting service to a Residential Applicant or Residential Customer, the Company may require payment of any outstanding balance which accrued within the past four years on any account for which the Residential Applicant or Residential Customer is legally responsible. The foregoing four-year limitation shall not apply if the outstanding balance includes past due amounts that the Company was not aware of due to Unauthorized Use of Service, fraud or theft; in which case, the Company may require payment of all such past due amounts without regard to the four-year limitation. The Company may render a make-up bill to a Residential Customer for previously unbilled service which accrued within the past four (4) years resulting from billing error, meter failure, leakage that could not reasonably have been detected or loss of service. If the make-up bill exceeds the otherwise normal estimated bill for the billing period during which the make-up bill is issued by at least 50% or at least $50, whichever is greater, the Company shall, at the option of the Customer, amortize the bill at least as long as: (1) the period during which the excess amount accrued; or (2) necessary so that the quantity of service billed in any one billing period is not greater than the normal estimated quantity for that period plus 50%.

(c) The Company may utilize all means of determining an Applicant's or Customer's liability for any outstanding balances, including, but not limited to, the following: (1) use of Company records that contain confidential information previously provided to the Company, (2) information contained on a valid mortgage, lease or deed, (3) other information contained in the Company's records that indicate that the Applicant was an adult Occupant during the time the balances accrued, (4) use of commercially available consumer credit reporting service, (5) use of commercially available skip tracing software that contains records of names and addresses, and (6) use of information contained in credit reporting data utilized by the Company.

(C) Indicates Change

RULES AND REGULATIONS

4. SERVICE - SUPPLY FACILITIES

4.1 Facilities Ownership. Unless otherwise mutually agreed in writing that particular facilities are owned by the Customer, and except as provided in Sections 4.3 below, the Company will own and maintain any facilities required for the supply of Gas Service up to the outlet side of its metering equipment, including but not limited to, any mains, service lines, meters, regulators, connections or other equipment. All such equipment shall remain the exclusive property of the Company.

4.2 Facilities Location. The location of the Company's facilities shall in all cases be determined by the Company. The Customer shall provide, without charge, a suitable place for the meters, regulators or other equipment of the Company. The Customer is responsible to provide the connection point to the Customer's fuel line at a location adjacent to the terminus of Company facilities and where the connections are not concealed. Such service line, meter and connection locations shall be accessible to the Company's employees for the safe installation, operation, inspection and maintenance of the facilities and shall be, at all times, readily accessible, and if inside, free of excessive temperature variations, with ample passageway, and whether inside or outside, free of obstacles, and unsafe and hazardous conditions and, if not accessible, the Company has ability to charge the Customer to move facilities to a location acceptable to the Company. The owner of a premises receiving or capable of receiving natural gas service from Company shall be deemed to consent to the location of Company facilities on the premises.

4.3 Customer Convenience Valve. Company may, in its sole discretion, install a valve on the outlet side of its metering facilities which shall be owned by the owner of the premises ("Customer Convenience Valve"), and the owner of the premises may, under such conditions as may reasonably be established by Company, operate the Customer Convenience Valve after it is connected to the premise's fuel lines.

4.4 Fuel Line Designation. When two or more meters are installed on one premises, such as an office building or an apartment house, they shall be grouped at one common place accessible for reading and testing. In such an installation, each fuel line pipe shall bear a tag showing the apartment or area served, supplied by and maintained by the Customer. In cases where it is not possible to group meters at one accessible place, they shall be located as directed by the Company.

4.5 Facilities Relocation.

(a) Changes in location of mains, service lines, meters, regulators, connections or other equipment for the accommodation of the Customer shall be done by the Company, unless otherwise mutually agreed, at the expense of the Customer. This provision includes the relocation of facilities by the Company where obstructions limit Company access to its facilities.

RULES AND REGULATIONS

4. SERVICE - SUPPLY FACILITIES - Continued

(b) Ancillary Fuel Line Work. The Company may, in its sole discretion, when relocating its facilities, make reasonable modifications or additions to the fuel lines of a premises receiving or capable of receiving gas service for the limited purpose of connecting such fuel lines to Company's relocated facilities, and the owner of the premises shall thereafter own and have responsibility for such modified fuel lines. If Company relocates its facilities solely for its convenience or to comply with regulatory requirements it shall pay the costs of relocating or extending the fuel line; otherwise, unless otherwise agreed by Company, the person requesting or requiring the relocation shall be responsible for payment.

4.6 Right of Removal. The Company shall have the right to remove its facilities from the premises of the Customer or, where appropriate, abandon facilities in place, at any time after the termination of service, whatever may have been the reason for such termination.

4.7 Non-Standard Service. The Customer may be required to pay the cost of any special installation necessary to meet Customer's requirements for Gas Service at non-standard conditions.

4.8 Protection of Company Facilities. The Company may condition its provision or continued provision of Gas Service to a Customer on: (a) installation by Customer of equipment, such as check valves or regulation equipment, downstream from Company-owned facilities reasonably necessary to protect Company facilities or service levels, or (b) the installation by Company of equipment, such as valves designed to limit the flow of gas to levels Customer is permitted to receive, reasonable necessary to protect Company facilities or service levels. Unless otherwise agreed to by the Company, the Customer shall be responsible for the costs of such facilities required under this Section 4.8.

4.9 Excess Flow Valves. The Customer may be required to pay the cost of installation of an excess flow valve, upon a Customer's request for an excess flow valve, for a service location that had not been scheduled by the Company for a service line replacement or a new service line prior to the Customer's request for the installation of an excess flow valve.

RULES AND REGULATIONS

5. EXTENSION REGULATION

5.1 Obligation to Extend or Expand.

(a) Under the rules set forth below and under normal conditions of construction and installation, upon written application, the Company will extend or expand its facilities within its service territory, provided that (a) the requested extension or expansion will not adversely affect the availability or deliverability of gas supply to existing customers and (b) the Company's investment in facilities is warranted by the Annual Base Revenue to be derived from the extension. The costs of extending or expanding facilities beyond the Company's Allowable Investment Amount shall be paid by the Extension Applicant as a contribution. Extension contributions may be excused, in whole or in part, in accordance with Rule 5.1(b). Upon request, the Company will provide Customers with a written explanation and reasonable detail of the cost-benefit analysis used in clause (b) above including estimated project costs, the Company's maximum allowable investment, and the Company's Annual Base Revenues. In addition, the Company will provide the Customer with a written timetable for the anticipated construction of the upgrade and written notice of completion.

(b) No contribution amount shall be required for an extension of facilities if all of the following conditions, as determined by the Company, are met:

(1) Service location is directly accessible from an existing or proposed (non-high pressure) Company main that would be extended up to one hundred fifty (150) feet;

(2) Service length is one hundred fifty (150) feet or less;

(3) Customer will utilize gas service as their primary heating source and be served under Rates R, RT, N or NT;

(4) Construction does not cross third party non-public property, private right-of-way or complex obstruction (stream, culvert, excessive hillside, etc.) and does not present any abnormal or unusual construction conditions or require unusual permitting requirements.

(5) Extensions not meeting all of the above conditions (1) through (4) shall have the Customer contribution amount determined upon incremental investment amounts required beyond those permitted by the construction conditions stated above.

(6) [REMOVED] **(C)**

(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION - Continued

(C)

5.2 General

(a) Annual Base Revenue. As used in this Section 5, the Annual Base Revenue is the anticipated annual base rate revenue from the extension or expansion, as determined by the Company, less the cost of fuel included in base rates. Where gas is used as a supplemental source of fuel for peak heating purposes, anticipated base revenues from such use shall be excluded from Annual Base Revenue.

(b) Allowable Investment Amount. The Company's Allowable Investment Amount shall be the Annual Base Revenue divided by a predetermined rate of return.

(c) Estimates and non-standard costs. Cost estimates used by the Company may be based on construction and installation conditions anticipated for the extension, including, but not limited to, the cost of installation and construction: non-street surface restoration, such as replacement or repair of sidewalks, driveways, landscaping or sod; street opening and restoration terms and fees; and any other local government fees required for the installation. The Company may determine cost estimates based on average experienced unit costs.

(d) Surface Restoration. The Company will restore the street surface in accordance with applicable local government regulations and provide rough backfilling of the installation trench from the curb to the meter. The Extension Applicant will be required to perform or pay the Company's cost of non-street surface restoration.

(e) Standard conditions of construction in a residential development, commercial park and industrial park include trenching provided by the developer.

5.3 Residential and Small Commercial Gas Service. For Gas Service to individually metered, single dwelling units, the Company will install required service facilities, including, as applicable, a meter, regulator, service-supply pipe and supply-main, provided the costs in excess of the Allowable Investment Amount shall be paid by the Extension Applicant.

5.4 Commercial and Industrial Gas Service (including apartment buildings and multi-unit housing)

(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION –Continued

(a) For commercial and industrial Gas Service costing up to $10,000 from which the Company in its sole judgment anticipates long-term, continuous usage at projected volumes, the Company will install, required service facilities, including, as applicable, a meter, regulator, service-supply pipe and supply-main, provided that the costs in excess of the Allowable Investment amount shall be paid by the Extension Applicant.

(b) The Company may condition its agreement to extend or expand its facilities upon satisfactory long-term and short-term usage commitments and any other terms and conditions of service as are mutually agreeable to the Company and the Extension Applicant. A contribution may be required up to the amount of the Company's total investment in the extension.

5.5 Contributions and Refunds

Except as otherwise described herein, when a contribution is required by the Company, the terms and conditions of refunds and or future payments that may be required of the Extension Applicant will be governed by the service agreement between the Company and the Extension Applicant. The terms of any refund due to the Extension Applicant shall be defined in the service agreement and shall be limited to a maximum refund of the amount of the original contribution (no interest) and shall be limited to the five-year period immediately following completion of this extension.

5.6 Taxes on Contributions for Construction & Customer Advances.

Any contribution, advance or other like amounts received from the Extension Applicant which shall constitute taxable income as defined by the Internal Revenue Service, will have the income taxes recorded in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with a contribution or advance will not be included as part of the contribution or advance charged to the Extension Applicant.

5.7 Daily Metering.

The Company reserves the right as a condition of service under non-residential Tariff rate schedules to install, at the Customer’s expense, remote read devices for the purposes of monitoring and/or billing Customer volumes, at every single meter or multimeter location served under such rate schedules. The Customer shall at all times, at the discretion of the Company, maintain, at its expense, a suitable telecommunication and electric lines to the device which will allow the Company unlimited remote access to the remote read device. If the Customer fails to maintain a suitable telecommunication connection and electric lines to the device, the Company reserves the right to install and maintain telecommunication and, as applicable, electric lines to serve the remote read device and charge the Customer accordingly.

Standard access to daily usage information shall be provided by the Company to the Customer, or Customer's agent, at no additional charge in a form and manner as specified by the Company. Custom reports, access to historical data beyond one month and/or multiple user access may be provided on an as-available basis by the Company for an additional fee.

RULES AND REGULATIONS **(C)**

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RULES AND REGULATIONS

6. CUSTOMER'S RESPONSIBILITY FOR COMPANY'S PROPERTY

6.1 Maintenance of Company Equipment. Company shall own and maintain Company facilities through the Point of Delivery but shall not be required to install or maintain any pipes, appurtenances or equipment beyond that point, unless specifically provided for in writing.

6.2 Access to Premises. The authorized agents and/or employees of the Company shall have free access at all reasonable times to the premises of the Customer for the purpose of reading meters and disconnecting service, for installing, testing, inspecting, repairing, adjusting or removing any Company property. Authorized agents of the Company shall have immediate access to any premises whenever they believe an unsafe or hazardous condition exists.

6.3 Protection by Customer. The Customer shall be responsible at Customers expense for the protection of the Company's property on his premises and shall not permit any unauthorized person to do any work on such property. In the event of damage or destruction of Company's facilities on Customer's property, the Customer shall pay the costs of repairs, replacement, and/or related costs.

6.4 Tampering and Theft of Service

(a) Tampering. In the event the Company's meter or other equipment is tampered or interfered with, the Customer shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations. Such tampering will be grounds for immediate termination of service without notice as specified in the Termination of Service and Disconnection section of this Tariff.

(b) Theft of service occurs when a person obtains gas, by deception, tampering with Company facilities or other means designed to avoid payment for gas provided by Company. Persons who obtain gas through such means may be subject to civil suit and/or criminal prosecution. If theft of service occurs, the Company may immediately terminate service to the location receiving the unauthorized service.

(1) Before service will be restored to the affected location, the Customer must pay (1) for all gas consumed during the period of unauthorized usage, (2) any delinquent gas service balance, including late fees, (3) reconnection fees, (4) a security deposit, and (5) the costs associated with damage to the Company's meters or equipment.

(2) In the event that the theft of service is referred for criminal prosecution, the Company may deny gas service until the case is concluded and any restitution ordered is paid.

RULES AND REGULATIONS

6. CUSTOMER'S RESPONSIBILITY FOR COMPANY'S PROPERTY - Continued

6.5 Continuity of Service. The Company will endeavor at all times to provide reasonable and continuous service to the Customer. The sole liability of the Company for failure to furnish a sufficient supply of gas or for failure to transport Customer's gas shall be limited to an amount equal to the Customer's proportionate monthly Customer charge for the period of time during which a Gas Service failure occurs during which a supply failure occurs. In no event shall the Company be liable for direct, extraordinary, special, or consequential damages arising in any manner whatsoever as a result of supply failure.

6.6 Notification of Construction. It will be the Customer's responsibility to notify the Company and any applicable federal, state or local agencies (i.e., Pennsylvania's One Call System, Inc.) prior to digging or before any construction occurs on the Customer's property that may impair or prevent access by the Company to its service line or any other equipment located on the Customer's property.

6.7 Gas Leaks. It is the responsibility of the Customer to exercise all due care in the detection of defects, leaks, or other dangerous developments incident to the handling of gas. The Customer agrees to immediately inform Company of any gas leaks and in the event of any resulting loss thereof, failure to do so may result in an evidentiary finding of contributory or comparative negligence on the part of the Customer.

6.8 Suspension of Service. For the purpose of making repairs to the mains or other parts of its system, the Company may suspend service for such periods as may in its sole judgment be necessary.

6.9 Company's Right to Inspect. Piping, fixtures and appliances on Customer's premises must be installed at the expense of the Customer or owner of the property. The Company shall have the right, but shall not be obligated, to examine the Customer's installation and appliances at the time service is first supplied or at any later time. If at any time the installation or appliance is found defective or unsafe, service may be refused or discontinued until Customer has the condition corrected. The Company's inspection, or failure to inspect or reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects or inadequacies in the installation, piping, or appliances, or from violation of the Company rules, or from accidents which may occur upon the premises of the Customer.

RULES AND REGULATIONS

7. METER READING

7.1 Definition of a Cubic Foot. A cubic foot shall be the amount of gas that occupies a volume of one cubic foot at an absolute pressure of 14.73 pounds per square inch and a temperature of 60° Fahrenheit. To determine the volume at conditions other than standard pressures of gas delivered, factors such as those for pressure, temperature, specific gravity, caloric value, and deviation from the laws of ideal gases may be applied.

7.2 Method of Measurement. Gas usage shall be measured by Company owned meters.

7.3 Pressure Correction. At the Customer's request, the Company may allow delivery at an elevated pressure that exceeds the standard pressure of seven-inches water column (7" W.C.). In situations where delivery pressure is two pounds per square inch or greater, the Company may choose to use a fixed factor to account for the higher energy content of the higher pressure gas, whereby the metered volume is multiplied by the pressure factor to determine the correct energy consumed. In cases where the Company agrees to provide delivery service at such an elevated pressure without a fixed factor, a supplemental device will be installed at the Customer's expense to correct the meter reading for pressure and temperature, the cost of which shall be estimated, inclusive of overhead amounts, however, the Company and Customer may negotiate cost responsibility for installation of pressure mechanisms upon mutual agreement. The Company may reject a Customer's request for non-standard service at elevated pressure for system operational reasons, where the Customer does not agree to pay the cost for non-standard service, where applicable, under Rules 4.7, 5.3 or 5.4(a), or for any other reason that the Company may determine at its sole discretion.

7.4 Heating Value Correction. Where direct sources of natural gas, renewable natural gas, synthetic natural gas or other natural gas substituted or blended supplies delivered into the Company's distribution system may vary in heating value content (BTUs per cubic foot), the Company may apply a heating value correction factor to metered usage to adjust for heating values that differ from the Company's applicable annual system wide average value (determined excluding direct sources where heating correction is being applied). This heating correction factor will apply when heating value differences exceed a 2% difference at the customer location. This factor may be adjusted monthly. This tariff provision only applies to decreased heating value content gas entering the Company's system. **(C)**

7.5 Meter Tests. The Company may, from time to time and at its expense, inspect and test its meters. The Customer has the right to have the Company test the meter in service at the Customer's premises, and, upon written request, the Company will, as applicable, remove, seal and test the meter in accordance with the Gas Service Regulations of the Pennsylvania Public Utility Commission ("Regulations") or secure an in-person meter reading to confirm the accuracy of an automatic meter reading device when a customer disconnects service or a new service request is received. Together with the written request for a meter test, the Customer shall deposit with the Company the meter testing fee specified by the Regulations. If the meter tests within the accuracy limits specified by the Regulations, the meter shall be deemed for all purposes to have registered accurately. In such case, no billing adjustment shall be made, and the meter testing fee deposited with the Company shall be credited to the Company. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

7. METER READING (Continued)

7.6 Adjustment for Meter Error. If any meter becomes defective or fails to test accurately, an adjustment will be made to the Customer's bill in accordance with the Regulations and the meter testing fee deposited with the Company shall be refunded to the Customer. **(C)**

7.7 Meter Test Fees. The Company may assess the following service charges: **(C)**

Meter Size:	
0 - 500 CFH	$10.00
501 - 1500 CFH	$20.00
Over - 1500 CFH	$30.00

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT

8.1 Billing Month. Bills are rendered monthly. The Company normally reads meters monthly. However, at its option, the Company may read meters once every two months. In instances where meters are read every two months, the first month's bill will be based on an estimate of the consumption for the first month of the bi-monthly period. Bills are due when rendered and shall be considered as received by the Customer when left at, or mailed to, the address where service is rendered, or such other address as designated by the Customer. A billing month is the period upon which a Customer's monthly charges and consumption are computed and for which a bill is rendered. For Residential Customers, the billing month is a period of not less than 26 or greater than 35 days. An initial bill for a new Residential Customer may be less than 26 days or greater than 35 days; provided however, if an initial bill exceeds 60 days the Residential Customer shall be given the opportunity to amortize the amount over a period equal to the period covered by the initial bill without penalty. A final bill due to the discontinuance may be less than 26 days or greater than 35 days but may never exceed 42 days. In cases involving termination, a final bill may be less than 26 days. In addition, bills for less than 26 days or more than 35 days shall be permitted if they result from rebilling initiated by the Company or Customer dispute to correct a billing problem. Bills for less than 26 days or more than 35 days shall be permitted if they result from a meter reading route change initiated by the Company.

8.2 Estimated Consumption. When the Company is unable to obtain an actual meter reading because of inability to gain access to the meter, or because of extreme weather conditions, emergencies, equipment failures, work stoppages or any other circumstances, the Company will render appropriately marked estimated bills.

8.3 Application of a Rate Schedule. The Company will compute bills under the rate schedule selected by and for which the customer qualifies. In the event the customer does not select a Rate Schedule, the Company may discontinue service or place the Customer on a rate schedule for which the Customer qualifies.

8.4 Budget Billing. Residential Heating Customers may elect an optional billing procedure which averages the estimated Company regulated service costs over a revolving twelve (12) month Budget Billing plan. These Customers will be billed for the use of gas during the next eleven (11) months beginning with whatever month that they select. Company will review the Budget Billing amount upon the completion of the third (3rd), sixth (6th), and ninth (9th) billing months with budget asked to pay amounts adjusting the fourth (4th), seventh (7th) and tenth (10th) billing months annually adjusting upward or downward the Budget Billing amount based on actual charges to date and projected charges to the end of the twelve (12) month Budget Billing. The twelfth bill will be for usage for the month, with an adjustment for the difference between payments made and actual charges for gas service for the prior eleven (11) months, inclusive. At the conclusion of the budget billing year, any resulting reconciliation amount exceeding $100 may be amortized over a twelve (12) month period upon Residential Heating Customer request. **(C)**

The optional twelve (l2) month Budget Billing plan, as described above, is available to Commercial and Industrial Heating Customers provided that at least seventy-five (75) percent of the Customer's total gas consumption is for space heating. If a Customer has an unpaid balance equal to the amount of two (2) Budget Bill Plan bills, billing under this plan may be terminated by the Company.

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued **(C)**

8.5 Payment Due Date. The due date for payment of Residential Customers' bills shall not be less than twenty (20) days from the date of mailing and fifteen (15) days for a Non-Residential Customer's bill with the exception that bills to the Commonwealth of Pennsylvania, the Government of the United States, or any of their agencies, and elementary and secondary schools shall be due fifteen (15) days after the date of mailing unless otherwise extended to thirty (30) days by mutual agreement. For all billings, if the due date for payment should fall on a Saturday, Sunday, bank holiday or any other day when the offices of the Company where payments are regularly received are not open to the general public, the due date shall be extended to the next business day. Failure to receive a bill will not release the Customer from payment obligations.

8.6 Date of Payment for Residential Customers. For payments by mail, the effective date of payment shall be the date of the postmark. For payments by mail which are not postmarked or postmarked clearly, the effective date of payment shall be one day prior to receipt. For payments made through electronic transmission, the effective date of payment shall be the date of actual receipt of payment by the Company. For payments made at a branch office or an Authorized Payment Agent, the effective date of payment shall be the date of actual receipt of payment at that location.

8.7 Late Payment Charge. Late Payment Charges will be applied as follows to the balance due which is not paid by the due date including amounts billed by the Company on behalf of natural gas suppliers other than the Company. Residential Customers will be charged a late payment charge of one and one half (1 1/2) percent per month on the balance due not paid by the due date; provided that, for a Residential Customer's payment by mail, the Company shall not impose a late payment charge unless payment is received more than 5 days after the due date. Non-Residential Customers will be charged five (5) percent per month on the balance due not paid by the due date and an additional one and one half (1 1/2) percent per month for each month thereafter.

8.8 Return Check Service Charge. The Company may impose a service charge of the greater of thirty-five dollars ($35.00) or maximum allowed by Commonwealth of Pennsylvania for each check received in payment of bill(s) which is dishonored and returned by the bank upon which it is drawn. The Company may require a Customer to tender non-electronic payment after the Customer tenders two (2) consecutive electronic payments that are subsequently dishonored, revoked, canceled or otherwise not authorized.

8.9 Due Date Extension Program. Residential Customers meeting the qualification requirements of the Due Date Extension Program shall, upon written application, have the due date for payment of bills for service to their personal residence extended. To qualify, Applicants must submit proof that their sole source of support, and that of others in their household, is derived from a permanent fixed income plan, issuing monthly checks. Under the program, the due date for payment on a bill normally falling due between the sixth day of the month and the twentieth day of the month shall be extended to the first working day after the twentieth of the month. The due date for payment on a bill normally falling due between the twenty-first day of the month and the fifth day of the following month, shall be extended to the first working day after the fifth day of the latter month.

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT – Continued **(C)**

8.10 Application of Payments for Rates RT and NT. Where Company renders a bill for natural gas supply service on behalf of a Choice Supplier and a partial payment received, the partial payment shall first be applied to pre-retail access Company balances and then to post-retail access balances. In the event a customer has a pre-retail access Company balance, partial payment shall be applied in the following order of priority:

1. First to outstanding pre-retail access Company balances, or the installation amount on a payment arrangement with the Company on this balance; then to
2. Current regulated Company charges; then to
3. Choice Supplier supply charges; then to
4. Non-Basic Service charges; then to
5. Hardship Energy Fund contributions.

In the event a Customer develops a post-retail access balance, partial payment shall first be applied to the pre-retail access Company balances in the order of priority specified above. Thereafter, partial payment shall be Company applied in the following order of priority:

1. First to outstanding post-retail access Company Balances, or the installat amount on a payment arrangement with the Company on this balance; then to
2. Current regulated Company charges; then to
3. Choice Supplier service charges; then to
4. Non-Basic service charges; then to
5. Hardship Energy Fund contributions.

Where Company renders a budget bill on behalf of a Choice Supplier for Natural Gas Supply service, partial payments shall be applied on a pro rata basis after outstanding pre-retail access balances and post retail access balances have been paid in accordance with the orders of priority specified above. For purposes of this Section, pre-retail access balances means outstanding account balances incurred prior to Customer transferring to Rate RT and NT.

For purposes of this Section, post-retail access balances means outstanding account balances incurred after Customer transfers to Rate RT and NT.

8.11 Joint Billing. Joint Billing provides Customers with one combined account and a combined invoice that displays charges for both their gas and electric service and pertains to Customers that are the same class as described below and receive both gas service from the Company and electric service from UGI Utilities, Inc. – Electric Division ("UGI-ED") at the same premises. Eligible Customers shall be Residential Customers receiving service under Rate Schedules R and RT who are also Residential Customers of UGI-ED receiving electric distribution service under UGI-ED Rate Schedules R, and Commercial and Industrial Customers receiving service under Rate Schedules N and NT who are also Commercial and Industrial Customers of UGI-ED receiving electric distribution service under UGI-ED Rate Schedules GS1, GS4, and GS5, unless they elect otherwise in writing or through mutual agreement with Company. Eligible Customers shall be combined into a single Customer account for service received from the Company and UGI-ED and shall receive combined bills

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued **(C)**

separately listing charges from each company. The Company and UGI-ED shall, for such combined accounts, and subject to applicable statutory and regulatory requirements, establish a reasonable hierarchy of categories for the posting of partial payments to such joint accounts, and within each such category payments shall first be posted, as applicable, to UGI-ED or Electric Generation Supplier charges before being posted to UGI Gas Division or Natural Gas Suppler charges.

8.12 Payment Refunds. Refunds due customers greater than two dollars ($2) shall be mailed to the Customer. Refunds less than two dollars ($2) may be picked up at the office within sixty (60) days. After sixty (60) days, the refund shall be applied to Operation Share.

8.13 Unless otherwise stated in this Section 8, Billing and Payment, all billing and payment provisions of this section apply to Customers served under all Company rate schedules, including Rate Schedules RT and NT where a Customer's Choice Supplier also participates in the Company's Purchase of Receivables ("POR") program.

(C) Indicates Change

RULES AND REGULATIONS

9. TERMINATION AND DISCONTINUANCE OF SERVICE

9.1 (a) Termination of Service. The Company may terminate service on reasonable notice and remove its equipment in case of Customer's (i) nonpayment of an undisputed delinquent account, (ii) failure to complete payment of a deposit, provide a guarantee of payment or establish credit, (iii) failure to permit access to meters, service connections or other property for the purpose of replacement, maintenance, repair or meter reading, (iv) failure to comply with the material terms of a payment arrangement, or (v) violation of tariff Rules and Regulations. The Company may terminate service promptly and without notice for Customer's (i) Unauthorized Use of Service delivered on or about the affected dwelling or premises, (ii) fraud or material misrepresentation of the Customer's identify for the purpose of obtaining service, (iii) abuse of or tampering with the meters, connections or other equipment of the Company, (iv) violating tariff Rules and Regulations which endanger the safety of a person or the integrity of the Company's distribution system, (v) tendering payment for reconnection of service that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice, or (vi) after receiving termination notice from the Company, tendering payment which is subsequently dishonored under 13 Pa. C.S. § 3502, or, in the case of an electronic payment, that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice. Prior to restoration of service terminated for any of the foregoing reasons, the Company may require a payment in advance of all arrearages, applicable deposit, and a reconnect charge of seventy-three dollars ($73). Effective November 1, 2025, confirmed low income Residential customers who provide verification of household income will not be assessed reconnection fees. **(C)**

(b) For Residential Customers, in the context of service termination during the period of December 1 through March 31, the Company will use financial information fro the Customer provided within the most recent twelve (12) month period to determine if a customer exceeds the 250% federal poverty level threshold. The Company will not require customer information to verify income if the customer has established income verificatior through receipt of LIHEAP within the past twelve (12) months or if the customer is currently participating in CAP. The Company will accept the following as verification of household income in determining whether an account under Chapter 56 is protected from termination during the period of December 1 through March 31: (i) recent pay stubs or W-2 forms, (ii) access card or statement from Department of Public Welfare ("DPW"), (iii) if a source of income is rental income, then a verified copy of rent receipt(s), (iv) if the Residential Customer receives social security payments, pension payments, disability payments, Supplemental Security Income (SSI) payments, or any other source of fixed income with direct deposit, then a copy of bank statement or benefit letter, (v) child support and/or alimony support verification letter, (vi) if the Residential Customer receives payments from unemployment benefits or workers' compensation, then a copy of the determination letter or check stub, (vii) previous year's income tax statement, (viii) a filed 1099 form showing any interest income, annuity or dividends, and (ix) a verification letter from DPW of any approved cash or crisis grant applicable to the current heating season.

(C) Indicates Change

RULES AND REGULATIONS

9. TERMINATION AND DISCONTINUANCE OF SERVICE - Continued (C)

9.2 Discontinuance of Service. Any Customer who is about to vacate any premises supplied with gas service or wishes to have service discontinued for any reason shall give at least seven (7) days written notice to the Company and any non-Customer Occupant of the premises to which service is being supplied, specifying the date on which it is desired that service be discontinued. If a Residential Customer requests a Discontinuance of Service at the Residential Customer's residence, and the Residential Customer and the members of the Residential Customer's household are the only Occupants, the Company may discontinue service without additional notice to the affected premise. If a Customer (other than a landlord ratepayer) requests a Discontinuance of Service at a dwelling other than the Customer's residence or at a single meter, multi-family residence, whether or not the Customer's residence, the Customer must state in writing (under penalty of law) that the premises are unoccupied. If the premises are occupied, the Customer's written notice requesting Discontinuance of Service must be endorsed by all affected Occupants. If the foregoing conditions are not met, the Company may discontinue service at the affected premises upon notice to the affected premises in accordance with Chapter 56. The Customer shall be liable for gas consumed until transfer of the account or the meter shut off. When Discontinuance of Service by Customer is for a period of less than twelve (12) months, the Company may require a payment of customer charges for each month the service has been discontinued in order to have the service restored.

9.3 If service to any Non-Residential Customer is terminated for the reasons set forth in Sections 9.1 (Termination of Service) or discontinued in accordance with 9.2 (Discontinuance of Service) hereof, the Company shall not be under any obligation to resume service to the same Customer at the same premises within twelve months unless it shall receive payment of an amount equal to the minimum bill for each month of the intervening period.

9.4 Reconnect Charge. If service to a Customer is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to such customer, at the same premises, within twelve (12) months from the date service was discontinued, unless they shall first receive a reconnection charge of Seventy-Three Dollars ($73.00). In addition, if the Customer's service was discontinued at the Customer's request, a payment of the applicable minimum charge for each month that service was discontinued shall be required. A Customer at the same premise who requests seasonal service and has gas shut off and turned on within twelve-month period shall be billed an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the twelve-month period.

(C) Indicates Change

RULES AND REGULATIONS

10. RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.01% **(I)**

This Rider applies to Rates R, RT, GL, N, NT, DS, and LFD.

(I) Indicates Increase

RULES AND REGULATIONS

11. RIDER B

SECTION 1307(F) PURCHASED GAS COSTS

Provisions for Recovery of Purchased Gas Costs

Rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R, N, and GL of this Tariff shall include purchased gas costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for gas service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the PUC's regulations, to reflect changes in the level of recovery of purchased gas costs.

Computation of Purchased Gas Costs per MCF

Purchased gas costs shall be computed to the nearest one-hundredth cent (0.01¢) per MCF in accordance with the formula set forth below:

$$PGC = \frac{(C-E)}{(S)}$$

Projected purchased gas costs, so computed, shall be included in rates charged to Customers for gas service pursuant to the rate schedules identified above for consecutive twelve-month periods. The amount of purchased gas costs per Mcf will vary, if appropriate, based upon annual filings pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the PUC's Regulations adopted pursuant thereto.

In the event a Natural Gas Supplier discontinues service or defaults before its contract with the Customer expires, any costs incurred by the Company during the period between the Natural Gas Supplier’s discontinuance of service or default and the first day of the Customer’s next regular billing cycle which cannot be recovered from the Natural Gas Supplier shall be considered a Purchased Gas Cost.

Definitions

In computing purchased gas costs pursuant to the formula above, the following definitions shall apply:

"PGC" - Purchased Gas Cost determined to the nearest one-hundredth cent (0.01¢) per Mcf to be included in rates for gas supplied under the rate schedules identified above.

"Purchased Gas" - The volume of gas purchased by the Company that is delivered to the Company's Customers, plus such portion of the Company's used and unaccounted-for gas, including, but not limited to, natural gas, synthetic gas, liquefied natural gas, and natural gas substitute, including liquefied propane and naphtha.

"C" - The current cost of gas (“C-Factor”) determined as follows: (a) for all types of purchased gas, project the cost for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect plus (b) the arithmetical sum of (1) the projected book value of noncurrent gas at the beginning of the computation year minus (2) the projected book value of noncurrent gas at the end of the computation year.

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

As applicable, to the extent such charges are not directly paid, Purchased Gas Costs shall include credits related to the use of PGC capacity by transportation customers where the Customer or NGS utilizes Company assigned or released pipeline capacity. In addition, revenues related to balancing services provided pursuant to Sections 22.2 and 22.4; Rate NNS; Rate MBS; capacity or commodity gas sales made pursuant to Customer elections under the Retail Standby Rider; Unauthorized Overrun; OFO, DFD and NGS penalty charges and bundled city gas sales made to NGSs shall be credited to the PGC. Such credits shall be reduced annually by the Economic Benefit Peaking Supply (EBPS Credit) reductions calculated pursuant to Rule 22.6 of the Rules and Regulations. **(C)**

"E" - Experienced net overcollection or undercollection of purchased gas costs ("E-Factor"). Such net overcollection or undercollection statement shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Each over-under collection statement shall also provide for refund or recovery of amounts necessary to adjust for over or underrecoveries of E factor amounts under the previous 1307(f)rate.

Interest shall be computed monthly at the rate provided for in Section 1307(f)(5) of the Public Utility Code from the month that the over or undercollection occurs to the effective month such overcollection is refunded or such undercollection is recouped.

Additionally, supplier refunds will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) calculated in accordance with the foregoing procedure, beginning with the month such refund is received by the Company.

Computation and Application of the E-Factor

The E-Factor shall be computed to the nearest one-hundredth cent (0.01¢) per Mcf in accordance with the formula set forth below:

$$\text{E-Factor} = (-E/S)$$

Each E-Factor so computed shall be applied to customer's bill for a one (1) year period during the Computation Year.

"S" - Projected MCF of gas to be billed to Customers during the projected period when rates will be in effect.

(C) Indicates Change

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

Revenue Sharing Incentive Mechanism: The PGC rate determined in this section may be adjusted to reflect the operation of a Revenue Sharing Incentive Mechanism as defined hereafter.

Off-system Sales: If and when the Company makes an off-system sale of natural gas, either in the Company's market area or upstream of the Company's market area with or without the use of PGC assets, the net revenues from the sale shall be shared by both the Company and the Company's retail customers served pursuant to this section of the tariff. The net revenues of the sale shall mean the total revenues from the sale of gas to a third party, less (1) the sum of the cost of natural gas, transportation commodity charges, and fuel retainage, if the sale or exchange is made upstream of the Company's market area or (2) the average city gate commodity cost of all gas purchased and flowing on the first of the month, including the natural gas, transportation commodity, and fuel, if such sale is made at the Company's city gate or in the Company's market area. The sharing of such net revenues shall be allocated in accordance with the Revenue Sharing Allocation procedure in this section.

Exchanges of Natural Gas: If and when the Company and a third party agree to make a location exchange of natural gas in which both parties receive like quantities of gas, with no adverse economic effect on the Company's Customers, any revenues received by the Company for performing this service shall be shared by the Company and the Company's retail Customers served pursuant to this section of the Tariff. Any revenues received from the exchange of natural gas, either upstream of the Company's city gate, or at the Company's city gate, shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section.

Capacity Release on Interstate Pipelines: Capacity release revenue generated by administrative releases to third parties that fill the Company's storage shall be credited 100% to PGC customers. Other revenue received by the company for off system Capacity Release of interstate pipeline capacity will be credited in accordance with the Revenue Sharing Allocation procedure in this Section.

Asset Management: If and when the Company has a third party manage gas supply assets paid for by the PGC, any revenues received from the third party ("Asset Management Fees") shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section. **(C)**

Revenue Sharing Allocation: Effective December 1, 2012, through November 30, 2026 the sum of the revenues derived from all Off-System Sales, Exchanges of Natural Gas, Capacity Release on interstate pipelines and Asset Management, will be allocated 75% to the retail customers served and 25% to the Company. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

The amount retained by the Company will be an incentive to pursue additional sales and will be treated below the line for ratemaking purposes. For purposes of calculating this margin, the cost of gas will be equal to the monthly average commodity cost of gas plus variable transportation costs to deliver the gas to the off-system customer. The monthly average commodity cost of gas shall be defined as the monthly average commodity cost of gas purchases for all supplies scheduled at the beginning of the month; provided, however, that if an additional unscheduled purchase is made during the month specifically for an off-system sale, such purchase shall be considered to be the gas used to make the off-system sale and the commodity cost of such purchase will be assigned to off-system sales up to the volume of the purchase.

Filing with the PUC: Audit, Rectification

The Company's annual reconciliation statement shall be submitted to the Commission by May 1 of each year, or such other time as the PUC may prescribe.

Quarterly Adjustments

When making the December 1, March 1, June 1 and September 1 quarterly C-factor adjustments, the Company will refund or recover all actual and projected incremental over or under collections from December 1 through November 30 over either remaining PGC year sales volumes or annual PGC year sales volumes, however the March 1 adjustment for projected over or under collections shall only utilize the remaining PGC year sales volumes. Any quarterly PGC rate change on December 1, March 1 and June 1 will be capped at 25% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. Any quarterly PGC rate change on September 1 will be capped at 15% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. The Company is authorized, at its sole discretion, to waive the quarterly cap on rate decreases only.

Rider B – Purchased Gas Cost (Mcf)

Annual C-Factor	$ 6.2323	**(D)**
Annual E-Factor	$ 0.5163	**(I)**
Total Purchased Gas Cost	$ 6.7486	**(I)**

(D) Indicates Decrease
(I) Indicates Increase

RULES AND REGULATIONS

12. Rider C

WEATHER NORMALIZATION ADJUSTMENT

Applicability and Purpose:

A Weather Normalization Adjustment ("WNA") shall be applied to bills of Residential and Non-Residential customers under Rate Schedules R, RT, N and NT, for any bills rendered during the heating season, which effective November 1, 2025 will include the months of October through April. Beginning with bills rendered on and after November 1, 2025, WNA will no longer be applied to confirmed low income residential customers who participate in the UGI Gas CAP program for CAP customers on a percent of income bill. CAP customers on average bill will continue to be billed based on an appropriate 12 month historic basis. The WNA commenced with bills rendered on and after November 1, 2022 and shall continue as a five-year pilot which will end on October 31, 2027, unless affirmatively extended or otherwise permitted by Commission Order. **(C)**

WNA is a distribution charge adjustment and is considered a basic service charge.

Calculated WNA amounts shall be subject to Rider A – State Tax Adjustment Surcharge and Rider I – Distribution System Improvement Charge. No additional riders or surcharges will be applied to the calculated WNA.

Calculation of Adjustment Amount:

The WNA will be applied to October through May billing cycles and shall be calculated on a customer account specific basis in accordance with the formula below:

WNBC = BLMC + [((NHDD +/- (NHDD * 3%)) / AHDD) x (AMC-BLMC)]
WNAC = WNBC – AMC
WNA = WNAC x Distribution Charge

(a) Weather Normalized Billing Ccfs("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of the Normal Heating Degree Days ("NHDD", adjusted for a 3% deadband as further discussed in subparts (i) and (j) below), divided by the Actual Heating Degree Days ("AHDD") and the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.

(b) BLMC shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a thirty-six-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent thirty-six months of bill history. If less than twelve months of bill history is available for the premise, an average base load for the related customer class will be applied.

(c) AMC shall be measured for each customer and billing cycle and will be inclusive of any heating value corrections.

(d) NHDD shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's 15-year average for the given day. NHDD shall be updated every 5 years using the methodology established in the Company's general rate case proceeding at R-2021-3030218 with the next scheduled update of the NHDD to be effective on October 1, 2025, and thereafter every five years.

(C) Indicates Change

RULES AND REGULATIONS

12. Rider C - Continued

WEATHER NORMALIZATION ADJUSTMENT **(C)**

(e) AHDD shall be the actual experienced heating degree days during the billing cycle for the customer's assigned Delivery Region, as determined by the customer's geographical location. A Delivery Region's AHDD shall be based upon experienced actual Gas Day temperatures as reported by the National Oceanic and Atmospheric Administration (NOAA) for weather stations located within that Delivery Region pursuant to the application of the Company's established Delivery Region calculation methodology.

(f) The period for which both NHDD and AHDD will be measured for each billing period used for the WNA calculation will be based on the starting day of the customer's billing cycle minus one day through last day of billing cycle minus one day. If AHDD is unavailable for any day(s) during that period, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any days missing AHDD from the WNBC calculation.

(g) AMC will be subtracted from the WNBC to compute the Weather Normalized Adjustment Ccfs ("WNAC").

(h) The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Rate Schedules R, RT, N and NT.

(i) A deadband of 3% shall apply. The WNA for a billing cycle will apply only if the AHDD for the billing cycle are lower than 97% or higher than 103% of the NHDD for the billing cycle.

(j) The WNA factor shall be calculated by first adjusting the NHDD for the billing cycle by the deadband percentage of 3%. The deadband percentage shall be multiplied by the NHDD and then added to NHDD for the billing period when the weather is colder than normal (i.e., AHDD>NHDD) or subtracted from NHDD for the billing period when the weather is warmer than normal (i.e., AHDD<NHDD).

(k) In the event a customer's bill needs to be canceled and rebilled at any time, the WNA will be recalculated using the most recently available data for the billing period. In some cases, updates in data used in the calculation, may result in a different WNA for the billing period. Bills requiring manual processing shall not have WNA applied.

(l) The Company will file reporting detailing weather normalization information with the Commission as outlined in the Final Order at the Company's Base Rate Proceeding at Docket No. R-2021-3030218.

(C) Indicates Change

RULES AND REGULATIONS

13. RIDER D

MERCHANT FUNCTION CHARGE

Applicability and Purpose

This Rider shall be applied to rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. The Rider is equal to the fixed percentage, established by the PUC in Company's last general base rate proceeding, of purchased gas costs which are expected to be uncollectible, and shall not be reconciled to reflect actual results. Rider D is intended to make Company's Price to Compare more comparable to the gas supply service prices offered of other Natural Gas Suppliers that presumably reflect anticipated uncollectible expenses.

Rider D Charge

Rider D charges shall be equal to 2.56% for Residential PGC Customers and 0.56% for Non-Residential PGC Customers of Rider B (Purchased Gas Costs). **(I)**

The collection of the Rider D charges will be summarized by Rate Schedule sub-accounts in the Gas Operating Revenue FERC Account No. 480000 for Rate R and 481000 for Rates N. The associated costs are recorded in FERC Account Nos. 904001 and 904002.

(I) Indicates Increase

RULES AND REGULATIONS

14. Rider E

GAS PROCUREMENT CHARGE

Applicability

This non-reconcilable Rider shall be applied to rates for each Mcf (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. Rider E shall be a volumetric charge as described below and shall remain in effect until reviewed and updated in the Company's next base rate case.

Rider E, or Gas Procurement Charge ("GPC"), recovers costs associated with gas procurement that were unbundled from base rates. The GPC rate is calculated by dividing total unbundled gas procurement costs by the sales volumes for the 12 months ending September 30, 2018, for Rate R and N.

Rider E Charge

Rates: R and N:	$ 0.0660 per Mcf

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	**Rate N (MCF)**	
Annual C-Factor	$ 0.62323	$ 6.2323	**(D)**
Annual E-Factor	$ 0.05163	$ 0.5163	**(I)**
Gas Procurement Charge	$ 0.00660	$ 0.0660	
Merchant Function Charge	$ 0.01728	$ 0.0378	**(I)**
Total Price to Compare	$ 0.69874	$ 6.8524	**(I)**

(D) Indicates Decrease
(I) Indicates Increase

RULES AND REGULATIONS

16. RIDER F

UNIVERSAL SERVICE PROGRAM

APPLICABILITY AND PURPOSE

This Rider shall be applicable to all residential customers except customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs.

RATE

In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each MCF of sales volumes or distribution volumes distributed by the Company to customers receiving service under Rate Schedules R and RT.

The USP rate: $0.6363/Mcf **(I)**

CALCULATION OF RATE

The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low-income program that is implemented during the period that the Rider is in effect.

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include
1) the projected CAP credit
2) projected CAP customer application and administrative costs; and
3) projected CAP pre-program arrearage forgiveness.

CAP Credit shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes.

(I) Indicates Increase

RULES AND REGULATIONS

16. RIDER F - Continued

UNIVERSAL SERVICE PROGRAM

QUARTERLY ADJUSTMENT

Any time that the Company makes a change in base rates or PGC rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION **(C)**

On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP and actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 9.2% adjustment for amounts granted to participants in excess of 25,404 (the number of CAP enrollees as of September 30, 2025). The 9.2% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following:

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits exceeding 25,404 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0920 in order to determine the amount of the CAP Credits which will not be recovered through Rider USP.

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness exceeding 25,404 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0920 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP.

(C) Indicates Change

RULES AND REGULATIONS

17. RIDER G

ENERGY EFFICIENCY AND CONSERVATION RIDER

Applicability and Purpose

The Energy Efficiency and Conservation Rider ("EEC Rider") shall recover costs related to the Company's Energy Efficiency and Conservation Plan ("EECP"). The EEC Rider shall be computed separately for each of the following four customer classes:

1. Residential customers served under Rate Schedules R/RT,

2. Non-Residential customers served under Rate Schedules N/NT,

3. Non-Residential customers served under Rate Schedule DS, and

4. Non-Residential customers served under Rate Schedule LFD.

EEC Rider Rate:

Rate R/RT	$0.1940/Mcf	**(I)**
Rate N/NT	$0.0259/Mcf	**(D)**
Rate DS	$0.0449/Mcf	**(D)**
Rate LFD	$0.0357/Mcf	**(I)**

The EEC Rider shall be subject to the State Tax Adjustment Surcharge.

Calculation

The EEC Rider shall be determined as follows:

1. Costs to be recovered shall include Company incurred costs to implement its Commission approved EECP during each plan year (October 1st through September 30th) (Plan Year), including all costs incurred to develop and administer the Company's EECP.

2. The Residential EEC Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

Residential EEC Rider = (Cr / Sr) – (Er / Sr) where

Cr = Projected Residential EECP Costs.

Sr = Projected Residential Class Sales.

Er = Net over or under collection of the Residential EEC Rider resulting from the difference between the EEC Rider revenues received and the EECP costs incurred.

(I) Indicates Increase (D) Indicates Decrease

RULES AND REGULATIONS

17. RIDER G - Continued

ENERGY EFFICIENCY AND CONSERVATION RIDER

3. The Non-Residential EEC Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

   Non-Residential EEC Rider = (Cn / Sn) – (En / Sn) where

   Cn = Projected Non-Residential EECP Costs.

   Sn = Projected Non-Residential Class Sales.

   En = Net over or under collection of the Non-Residential EEC Rider resulting from the difference between the EEC Rider revenues received and the EECP costs incurred.

4. The Residential and Non-Residential EEC Riders will be updated annually and will be filed with the Commission on one day's notice to be effective December 1 of each year. The Company reserves the right to make an interim filing to adjust the EEC Riders to be effective on sixty (60) days' notice. **(C)**

5. The Riders will be reconciled annually and will be filed with the Commission on or before November 1 of each year. **(C)**

6. If it is known that there will be a Phase III EE&C Plan at the end of the Final Reconciliation Year related to Phase II, any remaining balance will be recovered/refunded through the Phase III EEC Rider's E-Factor. If there will be no Phase III EE&C Plan, any balance remaining for a customer class at the end of the Final Reconciliation Year will be trued up through a one-time bill credit/debit issued to the applicable customers during the second full billing month following the end of the Final Reconciliation Year. The annual reconciliation and end-of-Plan reconciliation will be subject to Commission review and potential audit, as the Commission deems necessary. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

18. RIDER H

TECHNOLOGY AND ECONOMIC DEVELOPMENT RIDER

Availability. The Technology and Economic Development Rider("TED") is a negotiated rider available in the entire territory to Customers served by the Company which the Company determines, in its sole discretion, has prospective additional gas usage applicable to service under Tariff Rate Schedules N, NT, DS or LFD at the time of execution or renewal of a Service Agreement. The Rider TED is established for the purpose of adjusting the customer's overall distribution charge to address project specific or competitive issues to gain access to and expand use of natural gas within the Commonwealth of Pennsylvania. The negotiated Rider TED may be either a surcharge or credit depending on project specific customer and Company economic requirements, such that the overall economics must meet the requirements of Section 5.1 of this Tariff. Rider TED will be utilized to support the expansion of new technologies such as combined heat and power and natural gas vehicles, develop brownfields, and support economic development in Pennsylvania by facilitating business retention and attraction as well as other gas distribution system expansion activities.

General Terms. The Customer must execute a Rider TED service agreement.

MONTHLY RATE TABLE

Monthly Charge:	Negotiable
Plus	
Charge per Mcf:	Negotiable

RULES AND REGULATIONS

19. Rider I

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.33% will apply. **(I)**

19.A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

19.A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Piping, Couplings, Valves, Excess Flow Valves, Risers - Distribution & Transmission. (Accts. 374, 376, 365, 367)
- Measuring & Regulator Stations – Distribution & Transmission (Accts. 375, 378, 379, 366, 369, 370)
- Gas Service Lines and Insulated and Non-Insulated Fittings (Accts. 378, 380)
- Meters, Meter Bars, Meter Installations (Accts. 381, 382)
- House Regulators & Installations (Accts. 383, 384)
- Industrial & Farm Tap Measuring & Regulator Station Equipment (Accts. 385, 386)
- Miscellaneous Equipment and Material– Distribution & Transmission (Accts. 387, 371)
- Equipment – Electronic Systems & Software (Accts. 391)
- Vehicles, Power Equipment, Tools, Shop & Garage Equipment (Accts. 392, 394, 396)
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities.
- Gathering lines (Accts. 332)
- Storage lines (Accts. 353)
- Other related capitalized costs.

19.A.3 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

(I) Indicates Increase

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC-Eligible Plant Additions Reflected
April 1	December 1 through February 28
July 1	March 1 through May 31
October 1	June 1 through August 31
January 1	September 1 through November 30

19.A.4 Determination of Fixed Costs. The fixed costs of eligible distribution system improvements will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.
2. Pre-Tax Return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Utility's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of the Jurisdictional Utilities released by the Commission.

19.A.5 Application of DSIC. The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service under the otherwise applicable rates and charges, excluding amounts billed for the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of STAS.

Formula: The formula for the calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e)}{PQR} \quad \textbf{(C)}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

PTRR = Pre-tax return rate applicable to DSIC-eligible property.

STFT = State Tax Flow Through: pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **(C)**

Dep = Depreciation expenses related to DSIC-eligible property.

e = Amount calculated under the annual reconciliation feature or Commission audit, as described below.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be gained or lost by the beginning of the applicable service period.

Revenues will be determined as one-fourth (1/4) of projected annual revenues as determined in accordance with 19.A.7.5.

19.A.6 Quarterly Updates. Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Audits, Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

19.A.7 Customer Safeguards.

1. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.
2. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. § 1350, et seq., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year, or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. § 101, et seq.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.

(C) Indicates Change

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

1. New Base Rates: The DSIC will be reset to zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC. **(C)**
2. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert shall be included with the first billing
3. All Customer Classes: The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who are paying flexed or discounted rates and customers having negotiated contracts with the Company, if it is reasonably necessary to do so.
4. Earnings Reports: The DSIC will also be reset to zero, if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-days' notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.
5. Residual E-Factor Recovery Upon Reset to Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The utility shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 19.A.7.2. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

(C) Indicates Change

RULES AND REGULATIONS

20. Rider J

GAS DELIVERY ENHANCEMENT RIDER

Applicability and Purpose:
The Gas Delivery Enhancement Rider ("GDE") shall provide a mechanism to recover the portion of temporary mobile sources of gas supply and interstate pipeline demand charge enhancements (collectively "GDE Charges") that are incurred to achieve least-cost timely solutions to system reinforcement needs or for pipeline integrity management activities for customers taking service under Rate Schedules:(1) DS and (2) LFD. The allocation of GDE Charges to each of the foregoing Rate Classes will be established by the Company's annual Purchased Gas Cost Proceeding.

GDE Rider Rate:
Rate DS $0.0004 per Mcf (all volumes) **(D)**
Rate LFD $0.0004 per Mcf (all volumes) **(D)**

The GDE Rider shall be subject to the State Tax Adjustment Surcharge.

Calculation of Rate:
The GDE Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

$$\text{GDE Rider} = (F + De + Ca + EN)/(Mcf)$$

F = Fixed costs for physical infrastructure required to provide mobile sources of gas supply

DE = Demand enhancement charges

Ca = A commodity adder equal to the difference between the indexed price of natural gas for the affected portion of the service territory and the contracted price of alternative fuel that is used in lieu of natural gas during the system reinforcement.

EN = Net over or under collection of the GDE Rider resulting from the difference between the GDE Rider revenues received and the GDE Rider costs incurred.

Mcf = 1,000 cubic feet of gas supplied under Rate Schedules DS and LFD.

Annual Reconciliation:
In accordance with cost determinations in the Company's annual Purchased Gas Cost filings, GDE Rider costs and revenues will be reconciled on an annual basis that coincides with the Company's Purchased Gas Cost year for the period December 1 through November 30 and will be filed with the Commission on one day's notice to be effective December 1 of each year. Any over or under collection at the end of the period above shall be recovered or refunded through continuation of the GDE Rider until full recovery or refund has occurred.

(D) Indicates Decrease

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING

21.1 Company's Right To Reduce or Curtail Service. An emergency exists whenever the aggregate demand for firm service on the Company's system, or confined segment of the system, exceeds or threatens to exceed the gas supply or capacity that is actually and lawfully available to the Company to meet the demands, and the actual or threatened excess creates an immediate threat to the Company's system operating integrity with respect to Priority 1 Customers. In the event of a natural gas emergency, the Company shall have the right to impose a mandatory reduction or curtailment on any Customer's use of gas.

(a) Prior to taking any action under section 21.2 to curtail Customer usage, provided sufficient time exists as determined by the Company in its sole judgement, the Company shall use reasonable efforts and methods to: (1) interrupt all interruptible services, (2) issue Operational Flow Orders or Daily Flow Directives and, (3) call for voluntary usage reductions by any or all Customers.

(b) In planning for natural gas emergency situations, the Company shall make reasonable efforts to make contractual or informal arrangements with Customers and others which would allow the Company to obtain supplies or implement usage reductions in an effort to avoid or mitigate any emergency action pursuant to subsections 21.2 or 21.3 requiring firm service reductions. In making such arrangements, the Company may enter into specific negotiated terms, conditions and rates with any Customer or entity where a clear benefit exists to the Company for the management or avoidance of an emergency. Related costs, if any, may be included as gas costs for recovery under Section 11 of this Tariff.

21.2 Priority-Based Curtailments. In the event of an emergency, where the Company has mandated priority-based curtailments, the available gas supplies to the Company shall be prorated, if practicable, among Customers and NGSs according to the priorities set forth below, listed in descending order. Customers in a higher priority category shall not be curtailed until all Customers falling into a lower priority category have been curtailed to plant protection use levels, unless operational circumstances or physical limitations warrant a different result. Additionally, where only a partial restriction of a category is required, implementation shall be pro rata to the extent practical under the circumstances. Whenever possible, as determined by the Company in its sole discretion, allocation actions shall be limited to confined geographic or operational portions of the Company's system where the emergency exists.

(a) Priority 1. Service for residential and firm critical commercial essential human needs use.

(b) Priority 2. Firm service not included in Priority 1, which for purpose of curtailment shall be prioritized in the following subcategories:

(1) Firm small commercial and industrial service for plant protection under Rates N, NT, and DS.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING – Continued

(2) Firm large commercial and industrial service for plant protection under Rates LFD and XD.

(3) Firm commercial and industrial service under Rates N, NT, DS, LFD and XD, to the extent actual gas deliveries are being made to the Company's system on behalf of the Customer; all except for plant protection. **(C)**

21.3 Mandatory Reductions. In the event of an emergency under subsection 21.1, the Company may require each commercial and industrial retail and transportation Customer that is not a Priority 1 Customer to reduce its consumption of gas. In requiring mandatory reductions, the gas supplies available to the Company may be allocated to Customers in accordance with the priorities of use specified in subsection 21.2.

(1) The reduction required shall be determined by the Company without regard to priorities of use, as necessary to minimize the potential threat to public health and safety.
(2) The mandatory reduction shall be for a period specified by the Company and may be until further notice. The Company may change a Customer's authorized usage, upon notice, at any time during an emergency.
(3) Mandatory reductions shall be for a maximum duration of five (5) consecutive business days, unless extended by PUC order.
(4) Except as provided in 21.3(5), the minimum authorized usage may not be lower than the minimum usage of firm service necessary for plant protection use.
(5) When all other service has been curtailed except for Priority 1 service and the Company continues to be unable to meet Priority 1 requirements, the Company shall exercise its judgment as to any further curtailment that may be necessary and shall utilize measures designed to minimize harm to Customers if curtailments to plant protection use are found to be necessary.
(6) Consistent with its responsibility to maintain system integrity at all times, the Company shall provide periodic status updates and restore service as soon as practicable to any gas-fired electric generation facility that is deemed critical to electric system reliability by the electrical system's control area operator.
(7) Transportation Customers and NGSs are required to deliver, or cause to be delivered, natural gas supplies to the Company's system during an emergency, regardless of any mandatory gas consumption reductions imposed by the Company on such transportation Customers or NGSs' Customers. Such natural gas delivery may be required up to the Customer's or NGS's applicable DFR, MDQ, DDR or otherwise specified daily delivery quantity as determined by the Company in its discretion.

(C) Indicates Change

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING - Continued

21.4 Notice of Restriction or Curtailment

(a) Notice of any restriction or curtailment shall be made to affected Customers or NGSs via methods and mediums most reasonably expected to accomplish such notice; these may include, but are not limited to: telephone, facsimile, website, or electronic data exchange. If necessary, the Company will make notice through the media in order to communicate specific requests to large groups of Customer categories that are affected, including any relevant geographic limitations.

(b) It is the Customer's or NGS's responsibility to provide the Company with appropriate contact information, and to keep such information updated, in order to assure timely and efficient notices can be provided.

(c) The Company shall endeavor to provide the maximum notice time possible in the event of any notice of restriction or curtailment.

(d) The Company shall provide specific restriction or curtailment notices stating gas usage reduction percentages, absolute usage allowances or other reduction actions. In addition, the Company shall specify compliance timelines and restriction or curtailment durations as appropriate for the circumstance.

21.5 Emergency Allocation. The Company reserves the sole right to authorize exemptions in cases of verified Customer emergency situations affecting health and welfare.

21.6 Definitions

(a) Residential Use - Gas usage in a residential dwelling or unit for space heating, air conditioning, cooking, water heating, or other domestic purposes; all residential Customers served under Rates R, RT, and GL and apartments served under Rate N, NT, and GL, or subsequent rates classified by the Company as residential.

(b) Firm Service – Natural gas service offered by the Company to Customers under Tariffs or contracts that anticipate no interruptions. Such schedules are Rate R, RT, GL, N, NT, DS, LFD, and XD or subsequent firm rate schedules.

(c) Commercial Use – Gas usage by Customers engaged primarily in the sale of goods or services including consumption by office buildings, institutions and government agencies, and classified as commercial class for Company accounting purposes. Commercial Customers are served under Rates GL, N, NT, DS, LFD, XD, and IS or subsequent rates classified by the Company as commercial.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING – Continued

(d) Essential Human Needs Use - Gas usage into any building where persons normally dwell, including residences, apartment houses, dormitories, hotels, hospitals and nursing homes.

(e) Industrial Use - Gas usage by Customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power and classified as industrial for Company accounting purposes. Industrial Customers are served under Rates GL, N, NT, DS, LFD, XD, and IS, or subsequent rates classified by the Company as Industrial.

(f) Plant Protection Use - Minimum usage of natural gas required to prevent physical harm to an industrial or commercial consumer's plant facilities or danger to plant personnel at the facility when the protection cannot be afforded through the use of an alternate fuel. Plant protection uses include usage necessary for the protection of the material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

21.7 Limitation of Liability.

In the event of any limitation of service or curtailment, the Company may restrict, curtail or discontinue service in accordance with this Section 21, or PUC order, without incurring any penalty or liability for any loss, injury or expense that may be sustained by the Customer except when the restriction or discontinuation of service is a result of the Company's willful or wanton misconduct.

21.8 Appropriation Liability.

(a) The Company may appropriate natural gas and/or pipeline capacity pursuant to this Section 21, a PUC policy statement, directive or order, or an emergency order issued by the Governor of Pennsylvania.

(b) The Company shall compensate the Customer or the Customer's NGS for the cost of appropriated gas supplies. The compensation, in the aggregate, shall equal but not exceed, the greater of:

(1) the city gate cost of the appropriated natural gas including all transportation charges up to the Company's city gate; or,

(2) the reasonable cost actually paid by the Customer or the Customer's NGS for delivered substitute energy, as documented by the Customer or the Customer's NGS and presented as evidence to the Company. Such compensation may be a later delivery of in-kind gas service at the sole discretion of the affected Customer or NGS.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING - Continued

21.9 Discontinuance of Service.

The Company may discontinue service at its sole discretion, without notice, for the duration of an emergency, to any Customer that continues to take gas in violation of any rules, notice of limitation or curtailment provided for under this Section 21.

21.10 Penalties for Unauthorized Takes.

(a) The Company may, in its sole discretion, issue penalties for any unauthorized taking of gas to any Customer failing to comply with any restriction or curtailment made under this Section 21.

(b) The penalty for unauthorized takes associated with this section shall be equivalent to those for a Critical Day in Section 22.4 General Terms for Delivery Service For Rate Schedules DS, LFD, XD, and IS - Maximum Daily Excess Balancing Charge. Payment of penalties under this section shall be in addition to any liability for direct or indirect damages resulting from Customer's or Customer's NGS failure to comply.

(c) The Customer shall be liable to the Company for any costs incurred in taking action to discontinue service in accordance with actions taken under subsection 21.9.

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS (C)
Effective November 1, 2020

22.1 Application of Rates **(C)**

(a) Applicable Rates: DS, LFD, XD and IS.

(b) Notification of Delivery; Nomination Procedures. Customer shall notify the Company of any and all gas deliveries to the Company's system, including, but not limited to, the provision of nomination, revised nomination and scheduling information, in accordance with the Company's *Nomination Procedure*, as may be amended from time to time, and made available on the Company's Gas Management Website ("Nomination Procedure"). The quantity of gas received on behalf of the Customer shall be determined by allocation or other method by the Company if required in its sole discretion. It is the Customer's responsibility to arrange that any necessary billing information be provided to the Company and/or delivery gas source.

(c) Nominating Agents. A Customer shall notify the Company of its designated nominating agent ("Agent") for purposes of nominating the volumes of natural gas to be delivered to the Company's system on the Customer's behalf in accordance with the Nomination Procedures. Customer shall notify Company, on a form designated by the Company in the Nomination Procedures, of the responsibilities of the Agent, and shall provide Company with the Agent's valid e-mail address and valid 24-hour contact information. Customer shall remain liable for all charges and penalties notwithstanding Customer's designation and use of an Agent in accordance with the provisions herein.

(d) Penalties for Customer's Default. Customers failing to provide nomination, billing, scheduling, agent, supplier and/or other required information to the Company or pipeline(s)in accordance with the provisions of the Tariff, or otherwise failing to comply with the Company's *Nomination Procedure*, shall be subject to applicable imbalance charges and, in addition, be charged an Administrative Scheduling Fee in an amount no greater than $1,000 per day for every day such required information is delayed. If a Customer default of these provisions occurs and is occurring for a period of 90 days, the Company may impose retail or standby rates on the Customer's account beginning the first day after such 90-day period through and until such time as the Company deems the Customer default to have been resolved.

(e) Sequencing for Billing. Unless otherwise agreed by the Company and the Customer, customer-owned gas delivered under the transportation rate schedules shall be sequenced for billing as the first gas through the meter, and gas purchased under the Retail and Standby Rider shall be sequenced for billing purposes as the last gas through the meter. Gas billed under firm rate schedules shall be billed prior to gas billed under interruptible rate schedules. In lieu of otherwise specified tariff provisions, where the Company and Customer agree, Company shall use pipeline metering facilities for measuring and billing total deliveries to the Customer's facility.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued **(C)**

(f) Payment of Charges, Penalties. The Customer shall pay the Company for any and all additional charges incurred on the Customer's behalf or resulting from the Customer's actions or inactions which the Company can demonstrate arise out of the provision of transportation service including, but not limited to, pipeline transportation and service charges. Any such charge, penalty or obligation imposed by a pipeline transporter or supplier as result of balancing of gas delivered to the Customer shall be paid by the Customer in addition to otherwise applicable charges.

(g) The Billing Pool Agent is required to notify Company at least ten days prior to dropping a Customer from a Billing Pool. If adequate advance notice is not provided, the Company reserves the right to not drop the Customer from the Billing Pool.

(h) Billing Pools. One or more transportation Customers may join together in pooled transactions for the purchase and delivery of gas. The Company may allocate among all such customers the volumes of gas or imbalances for purposes of determining responsibility for charges, rates, penalties or other obligations imposed by the Company, or in connection with operation of the pool. A Supplier to a Billing Pool must notify the Company prior to initiating gas deliveries. A Customer is required to submit in writing a request for entry into a Billing Pool.

(1) Each Billing Pool shall appoint an Agent who will coordinate nomination, billing, reconciliation, allocation and any other necessary communication between the Billing Pool and the Company.

(2) All members of a Billing Pool shall be of like balancing service election. The Company may restrict formation or operation of any Billing Pool in order to meet like balancing service election or pipeline imposed eligibility requirements.

(3) Automated Meter Reading. The Company has the right as a condition of being a pool member, to install, at the Customer’s expense, automated meter reading (“AMR”) equipment for the purposes of daily collection or monitoring, and billing Customer volumes at each related service meter. Where AMR equipment is installed, the Customer shall maintain, at its expense, unless otherwise directed by the Company, a dedicated phone connection and electric service to the AMR equipment which will allow the Company unlimited remote access to the AMR device at all times. Failure to maintain a required phone and/or electric service may result in Customer being removed from a Billing Pool and being placed on a rate schedule not requiring daily measurement capability.

(4) Service under Rate NNS is required by, and shall be individually billed to, any and all members of a Billing Pool except when all pool members are monitored on a daily basis through the use of Company owned AMR equipment at all meter locations. Additionally, service under Rate MBS is required by, and shall be individually billed to, any and all members of a Billing Pool when the billing month for each pool member does not end on the same calendar date; Billing Pools having all customers monitored and billed through the use of Company owned AMR equipment at all meter locations shall be exempt from this requirement.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

(i) Recognition of Supplies. Volumes transported on behalf of the Customer will be recognized in the Customer's current billing month based on nominated or scheduled volumes information and may be adjusted after notification is received from the pipeline supplier(s) of the volumes transported on behalf of the Customer. Volumes scheduled shall be determined on the basis of best available actual or confirmed pipeline and/or Company information at the time of billing.

(j) Unless otherwise negotiated under Rate XD, the Company shall retain for Company use gas, and lost and unaccounted for gas, 1.5% of the total volume of gas delivered into its system for the Customer's account. **(I)**

22.2 Balancing and No-Notice Service.

(a) Each Customer shall use best efforts to balance purchases, deliveries and receipts of gas at all times. Except as specified in 22.1(f), for the purposes of balancing excess deliveries and shortfalls and purchasing services under Rates NNS and MBS, Billing Pools may be treated as a single entity. Subject to the terms and conditions set forth below, the Company shall provide no-notice and monthly balancing services under Rate Schedules NNS and MBS. Service under Rate Schedules NNS and MBS is available only for inadvertent fluctuations, limited by the terms and conditions of each Rate Schedule, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. In the event the Customer fails to use best efforts to balance deliveries and receipts, or otherwise misuses no-notice or balancing services as determined by the Company in its sole discretion, Section 22.4 shall apply for the period of such default or misuse.

(b) Daily Balancing. The Company shall allow Customer's daily demand to inadvertently vary from daily scheduled deliveries by +/-4.5% without imposing Daily Balancing Charges, provided the total daily quantity taken does not exceed Customer's Daily Firm Requirement, MDQ or otherwise specified contract demand limit. Daily imbalances in excess of the +/-4.5% tolerance, unless otherwise provided by service elected under Rate NNS, shall be assessed a Maximum Daily Excess Balancing Charge in accordance with Section 22.4 under Critical Day and Non-Critical Day criteria unless otherwise specified in Customer's contract, in addition to the charges specified in Rates DS, LFD, XD and IS, on all such quantities.

(c) Imbalance Resolution. Customer's monthly imbalances will be calculated at the end of each billing period to determine if any overdelivery (excess) or underdelivery (shortfall) condition exists for volumes scheduled versus volumes metered. If the Customer is determined to be in an imbalance condition, and has not elected service under Rate MBS or has exceeded the 10% imbalance allowance provided under Rate MBS, then the Company shall sell and the Customer shall buy, subject to the 5 percent limitation under Rate MBS, any shortfall amount according to the following cash-out pricing:

(I) Indicates Increase

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

Shortfall Percent	Cash-Out Price
Up to 5%	Shortfall Monthly Reference Price("SMRP")
Greater than 5%, but not greater than 15%	SMRP x 1.1
Greater than 15%, but not greater than 25%	SMRP x 1.3
Greater than 25%	SMRP x 1.5

(C)

Likewise, the Customer shall sell, and the Company shall buy any excess amount according to the following cash-out pricing:

Excess Percent	Cash-Out Price
Up to 5%	Excess Monthly Reference Price("EMRP")
Greater than 5%, but not greater than 15%	EMRP x 0.9
Greater than 15%, but not greater than 25%	EMRP x 0.7
Greater than 25%	EMRP x 0.5

(C)

The SMRP (Shortfall Monthly Reference Price) shall be the average of the DPP midpoint Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below: **(C)**

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The EMRP (Excess Monthly Reference Price) shall be the average of the DPP midpoint Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below: **(C)**

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C)

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

Customer Delivery Region shall be assigned to each Customer in accordance with Customer's delivery location within the Company's distribution system.

The SMRP and EMRP are applicable to the above tables only for inadvertent monthly imbalances. The HMRP (Highest Monthly Reference Price) or the LMRP (Lowest Monthly Reference Price) as defined below shall apply respectively to shortfall and excess conditions in those situations where intentional imbalances are involved. **(C)**

The HMRP shall be calculated as the highest of the DPP absolute Reference Prices for the Customer's Delivery Region during the Customer's billing month as listed below: **(C)**

Delivery Region	Reference Price	**(C)**
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.	
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.	
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.	
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.	

The LMRP shall be calculated as the lowest DPP absolute reference prices for the Customer's Delivery Region during the Customer's billing month as listed below: **(C)**

Delivery Region	Reference Price	**(C)**
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.	
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.	
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.	
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.	

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued **(C)**

(d) The Company may extend the balancing period for gas volumes and may increase volumes eligible for balancing in its discretion, but only if it determines that such action is consistent with its obligations to other customers.

(e) Supply Transfers. In order to facilitate Monthly balancing related to inadvertent imbalances in Company's sole discretion, the Company shall allow Supply Transfers among Customers and Billing Pools, Customers-to-Billing Pools and Billing Pools-to-Customers at a fee of $125 per transaction, provided however: (1) such transfer is requested prior to the end of the billing month for both the transferee and the transferor, (2) such transfer is physically possible given pipeline interconnection and delivery point limitations which require transfers to be between parties located on the same segment of the Company's distribution system, and system supplies, and reliability are not adversely affected.

(f) Competitive Volume Customers. In the case of Customers or applicants seeking service for facilities with a design volume capability allowing for direct connection to transmission or gathering lines for bypass of Company facilities, Company shall have the right to establish daily and monthly balancing tolerances at levels other than those specified in subsections (b) and (c) of this Section 22.2 to reflect specific operational limitations or to protect the interests of other Customers, as determined by the Company in its sole discretion. Additionally, the Company may establish special nomination rules, imbalance resolution rules and communication protocols that reflect the Customer's or applicant's commercial alternatives, and which are consistent with its obligations to other Customers.

22.3 Service Agreement and General. **(C)**

(a) Limitation on Liability.

(1) The Company shall not be liable for curtailment of service under Rates DS, LFD, XD and IS, or loss of the Customer's gas as a result of any steps taken to comply with any law, regulation or order of any governmental agency with jurisdiction to regulate, allocate or control gas supplies or the rendition of service hereunder, and regardless of any defect in such law, regulation or order.

(2) Gas transported and delivered by the Company to the Customer hereunder shall be and remain the property of the Customer. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during and after receipt by the Company.

(3) The Company shall not be liable for any loss to the Customer arising from or out of service hereunder, including loss of gas in the possession of the Company or any other cause, except gross or willful negligence of the Company's own employees or agents. The Company reserves the right to commingle gas of the Customer with other supplies.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

(b) Warranty, indemnity and special provisions. The receipt of service constitutes Customer's agreement to the following representations and warranties, together with related provisions in the service agreement:

(1) clear and marketable title to the Customer's gas;
(2) delivery points, pressure, quality and other specifications acceptable to gas transmission pipeline(s) and the Company;
(3) eligibility of the Customer for service;
(4) existence of lawful authority for sale, transportation and delivery;
(5) agreement to pay all excise, sales, use, gross receipts, or other taxes (other than income taxes), all tariff charges and all penalties, charges, fees for transportation, balancing etc., associated with delivered gas, which may be levied upon or incurred by the Company at any time;
(6) agreement to indemnify and hold the Company harmless from breach of representations or warranties, and any liability associated with Customer's gas while on the Company's system.

Copy of Gas Purchase Agreements, Other Documents. When requested by the Company, the Customer shall provide the Company with a copy of Customer's gas purchase contract and any related transportation, marketing and brokerage contracts, or, in lieu of providing such contracts, certify pertinent information as required by the Company, and, in order to meet state or federal requirements, provide a sworn affidavit setting forth the Customer's cost of gas for the period requested by the Company. The Company shall endeavor to protect the confidentiality of information provided by the customer in accordance with this provision. The Company will provide such information to third parties only when required to do so by law, regulation or order and in such case, will attempt to maintain confidentiality to the extent possible.

22.4 Maximum Daily Excess Balancing Charge

The Daily Excess Balancing Charge that occurs on Critical Days shall be as follows:

The charge for exceeding daily balancing limits shall be ten times the highest price in the DPP for each delivery region as listed in the following table. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into Pennsylvania. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

Delivery Region	Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.
Central	The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco Zone 6 to Zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C)

The Daily Excess Balancing Charge that occurs on Non-Critical Days shall be as follows:

Daily Imbalance Percent	Penalty
Up to 15%	DRP
Greater than 15%, but not greater than 30%	DRP x 2
Greater than 30%, but not greater than 45%	DRP x 3
Greater than 45%, but not greater than 60%	DRP x 4
Greater than 60%	DRP x 5
Intentional imbalances	DRP x 5

(C)

The DRP (Daily Reference Price) shall be equal to the difference in price between the highest DPP Reference Price and the lowest DPP Reference Price for the Customer's Delivery Region as listed below but shall not be lower than $0.25/Mcf. (C)

Delivery Region	Highest Reference Price	Lowest Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.	Tennessee, zone 4- 300 leg
Central	Transco zone 6, non-N.Y.	Transco, Leidy line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C)

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 – Continued

The Company shall not charge any Maximum Daily Excess Balancing Charges if the Customer's Excess Daily Imbalance is anticipated to benefit the distribution systems daily balancing position as determined by Company in its sole discretion.

22.5 Operational Flow Orders and Daily Flow Directives

The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Twenty-Five ($25) per Mcf or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater.

22.6 Cost of Assigned Capacity.

In addition to applicable interstate pipeline demand charges, the associated demand charges to customers, or their NGS, served under Rates DS, LFD, XD, and who utilize assigned PGC capacity and pay weighted average cost, will include 100% (DS) and 50% (LFD, XD) pro rata allocation of annual Peaking Supply service demand costs. The associated demand charges will be reduced by a pro rata share of the Economic Benefit of Peaking Supply (EBPS Credit). The EBPS Credit shall mean a pro rata share of (a) the value of Peaking Supply utilized in off system sales transactions and included in the PGC share of the Revenue Sharing Incentive Mechanism revenues, plus (b) the Commodity Price Differential, which shall be, as measured for the date of Peaking Supply delivery, the aggregate difference, if positive, between the DPP Reference Price applicable to the zone of delivery (i.e., Texas Eastern M3 for deliveries in the South and West Delivery Regions with the exception of deliveries from Mt. Bethel and Transco Z6 NNY for deliveries made in the North and Central Delivery Regions and deliveries from Mt. Bethel) and the actual price paid for actual Peaking Supply deliveries into the UGI distribution system. The EBPS Credit shall be applied in the calculation of associated demand charges in the second billing month after the credit has accrued (e.g., December accrued credits will be used to reduce the February associated demand charges) and shall not, on an annual basis, exceed the annual incremental demand charges for Peaking Services charged to Rate DS, LFD, and XD customers, or their NGS, as described above. **(C)** **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS

23. GENERAL TERMS FOR INTERCONNECTION COORDINATION SERVICES FOR CONNECTING ENTITIES

Any entity with actual or potential sources of gas supply connected to Company facilities (Connecting Entity) shall be obligated to enter into an agreement with the Company (Coordination Agreement) addressing, to the extent applicable: (1) the duties and obligations of the parties with respect to their respective facilities, (2) measurement of deliveries of gas, (3) gas quality standards, (4) nomination requirements, (5) permitted variations in supply deliveries and imbalance resolution and (6) other operational issues raised by the nature of the supply source connection

RULES AND REGULATIONS

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(C) Indicates Change

RULES AND REGULATIONS

25. Page Intentionally Left Blank (C)

(C) Indicates Change

RATE R

GENERAL SERVICE – RESIDENTIAL

AVAILABILITY

This rate applies to all Residential Customers in the entire gas service territory of the Company and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $16.25 per customer **(I)**

Plus Distribution Charge: $0.63317/Ccf **(C,I)**

Plus SURCHARGES and RIDERS

Rider A – State Tax Adjustment Surcharge
Rider B – Section 1307 (f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment
Rider D – Merchant Function
Rider E – Gas Procurement Charge
Rider F – Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change

RATE RT

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies to all Residential Customers in the entire gas service territory who are served by a qualified Choice Supplier receiving service under Rate AG and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $16.25 per customer **(I)**

Plus Distribution Charge: $0.63317/Ccf **(C,I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C - Weather Normalization Adjustment
Rider F - Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change

Rate RT - Continued

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RULES AND REGULATIONS

Where a Customer is returned to the Company or an alternate Supplier of Last Resort prior to the next regular meter reading date, due to the Licensed Choice Natural Gas Supplier's non-performance, Customer will receive service from Company or alternate Supplier of Last Resort for the remainder of the billing month at the contract rate between the Customer and Choice Supplier. Customer must provide evidence of the applicable contract rate, if requested by Company, to receive the contract rate price. As of the next regular meter read date, Customer will be transferred to Rate R, unless enrolled as a Rate RT customer by another Choice Supplier, effective as of the next regular meter read date.

GENERAL TERMS

Company Use and Unaccounted For gas shall be retained in accordance with Section 5, Operational Requirements, paragraph 5.1, Daily Delivery Requirements, of the Gas Choice Supplier Tariff.

RATE GL

GENERAL SERVICE - GAS LIGHT SERVICE

AVAILABILITY

This service is available for street, highway, driveway or other lighting or sign illumination, where measurement by meter of the gas consumed is not practicable or economical. As used herein, "light" means a single lamp or sign having one (1) gas-flow orifice and one (1) or more mantles, and of a type approved by the Company.

MONTHLY RATE TABLE

Distribution Charge: $0.63317/Ccf **(C,I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B – Section 1307(f) Purchased Gas Cost
Rider I – Distribution System Improvement Charge

Monthly usage is assumed to be 1.8 Mcf, however, for larger consumption input fixtures, the Company reserves the right to modify.

BILLS DUE

All bills for continuing service are due each month when rendered, and the final due date stated on the bill shall be no less than fifteen (15) days from the date of presentation. Upon discontinuance of service, bills are due and payable upon presentation.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

SPECIAL TERMS AND CONDITIONS

Gas will be supplied to lights furnished, erected and maintained by the customer only when equipped with regulators and such devices as the Company considers necessary for turning lights on and off for maintenance and safety purposes.

(I) Indicates Increase (C) Indicates Change

RATE N

GENERAL SERVICE – NON-RESIDENTIAL

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Non-Residential Customers, using gas for any purpose including gas purchased by another public utility for resale. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate N service may not be applied to supplement or back up any transportation service.

MONTHLY RATE TABLE

Customer Charge: $36.42 per customer **(I)**

Plus Distribution Charge: $4.3004/Mcf **(C, I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B - Section 1307(f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment
Rider D – Merchant Function Rider
Rider E – Gas Procurement Charge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE
The Customer Charge as set forth above.

MINIMUM BILL PROVISION
If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT
In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change

RATE NT

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Customers who are served by a Choice Supplier receiving service under Rate AG, except residential Customers, using gas for any purpose. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate NT service may not be applied to supplement or back up any transportation or retail service.

MONTHLY RATE TABLE

Customer Charge: $36.42 per customer **(I)**

Plus Distribution Charge: $4.3004/Mcf **(C, I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Weather Normalization Adjustment
Rider G – Energy Efficiency and Conservation
Rider H - Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

The Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change

RATE NT – Continued

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RULES AND REGULATIONS

Where a Customer is returned to the Company or an alternate Supplier of Last Resort prior to the next regular meter reading date, due to the Licensed Choice Natural Gas Supplier's non-performance, Customer will receive service from Company or alternate Supplier of Last Resort for the remainder of the billing month at the contract rate between the Customer and Choice Supplier. Customer must provide evidence of the applicable contract rate, if requested by Company, to receive the contract rate price. As of the next regular meter read date, Customer will be transferred to Rate N, unless enrolled as a Rate NT customer by another Choice Supplier, effective as of the next regular meter read date.

GENERAL TERMS

Company Use and Unaccounted For gas shall be retained in accordance with Section 5, Operational Requirements, paragraph 5.1, Daily Delivery Requirements, of the Gas Choice Supplier Tariff.

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RATE DS

DELIVERY SERVICE

AVAILABILITY

This service applies in the entire territory served by the Company. Firm Delivery Service shall be provided for all volumes supplied by the Customer for which the Company has available on system delivery capacity, subject to Section 21 - Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

The Customer must execute a Service Agreement for not less than (1) one year. The contract shall continue in force for consecutive (1) year periods unless cancelled by the Customer upon ninety (90) days written notice to Company prior to the expiration of a contract term.

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable delivery service balancing provisions or in accordance with optionally elected and approved balancing or standby services.

Service under Rate DS is subject to the terms set forth under Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Capacity Charge if applicable, and the Distribution Charge as described below. The following are maximum rates.

Customer Charge: $300.00 per month **(I)**

Plus Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected MDQ.

Plus Maximum Distribution Charge: $3.3651/Mcf **(C,I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

(C) Indicates Change
(I) Indicates Increase

RATE DS – Continued

DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge and the Capacity Charge. **(C)**

The MDQ shall be the Company's contracted maximum firm delivery obligation to the Customer on any day. Service in excess of the MDQ is interruptible in accordance with the terms of Rate IS. **(C)**

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

(C) Indicates Change

RATE NNS

NO-NOTICE SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a service agreement with Company for service under Rate NNS. The term of the service agreement shall be concurrent with that of the Customer's underlying Delivery Service Schedule.

Service under this Rate is available for inadvertent fluctuations only and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided.

Service to large volume users, such as electric generation facilities, may be limited as determined by the Company. Service under Rate NNS is subject to the terms and conditions set forth under Section 22 General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

TERMS AND CONDITIONS **(C)**

Customers shall elect a specific level of no-notice service under this Rate. Such election shall be made through the specification of a No-Notice Allowance ("NNA"), in MCF per day, of an amount no less than 4.5% and no greater than 100% of Customer's Daily Firm Requirement, Maximum Daily Quantity or otherwise specified daily contract limit. The elected NNA shall be effective for a fixed period equal to the lesser of one year or the remaining balance of the Customer's service agreement or, a lesser time period mutually agreeable to both the Customer and the Company. In no instance shall a NNA be effective for a period of less than one month. Rate NNS service elections in excess of 4.5%, are interruptible.

No-notice service shall be provided under this Rate whereby the Company shall forward or bank no-notice supplies to the Customer on a daily basis in such amounts necessary to balance the Customer's daily deliveries with the Customer's daily consumption. Forwarded amounts shall be limited in amount by the lesser of the sum of the Customer's daily nomination plus elected NNA or, the Customer's DFR, MDQ or otherwise specified contract limit except as allowed. Banked amounts shall be limited to an amount no greater than the Customer's NNA election.

Customer electing an NNA shall be billed for no-notice service according to that specific level of service.

Volumes in excess of the daily limits shall be subject to Daily Excess Imbalance Charges as set forth in Section 22.4 General Terms For Delivery Service for Rate Schedules DS, LFD, XD and IS on all such excess quantities, in addition to the charges specified in the Customer's Delivery Service Schedule.

(C) Indicates Change

RATE NNS - Continued

NO-NOTICE SERVICE

EXCESS REQUIREMENT OPTION

The Excess Requirement Option is available on an interruptible basis to any delivery service Customer served under Rates XD, LFD. This Option shall extend the no-notice provisions of Rate NNS, on solely a best efforts basis, during periods where Customer's daily requirements exceed transportation contract service limits.

Customer must nominate a Daily Excess Requirement ("DER") under this Option in an amount no less than 5 Mcf per day and no greater than 25% of Customer's DFR or otherwise specified contract limit. On days where service under the Excess Requirement Option is required, Customer will have the right, subject to the terms and conditions set forth herein, to take gas in excess of Customer's DFR or otherwise specified contract limit provided such excess is no greater than the nominated DER amount.

Service taken in excess of the sum of Customer's DFR and DER on any day shall be considered Excess Take or Unauthorized Overrun as determined by Customer's Delivery Service Schedule and service agreement.

Unauthorized gas forwarded or returned to the Company by the Customer shall be considered imbalance gas and shall be subject to either the balancing provisions set forth under Section 22.2 of General Terms for Delivery Service for Rate Schedules DS, LFD, XD and IS or the Customer's otherwise applicable transportation balancing service.

MONTHLY RATE TABLE (Basic NNS Service)

$0.2200 per Mcf per day of elected NNA **(C, D)**

plus

MONTHLY RATE TABLE (Excess Requirement Option)

$4.50 per Mcf per day of elected DER.

(C) Indicates Change (D) Indicates Decrease

RATE MBS

MONTHLY BALANCING SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a Service Agreement with Company for service under Rate MBS. The term of the Service Agreement shall be concurrent with that of the Customer's underlying Rate Schedule.

Service under Rate MBS is available for inadvertent fluctuations only, limited to an amount not to exceed 10% of the customer's total scheduled deliveries for the month, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. Service under Rate MBS is subject to the terms set forth in Section 22 General Terms For Delivery Service for Rate Schedules DS, LFD, XD, and IS.

Rate MBS is available as a monthly banking service for Customer transportation deliveries. Service under Rate MBS allows Customer transportation imbalances (metered volumes less total scheduled nominations) which are within 10% of Customer's total scheduled nominations for the month to be carried forward in the Customer's MBS Account ("Balance Account") for redelivery of excesses or receipt of shortfalls in subsequent months.

TERMS AND CONDITIONS

Balance Account Operation. To the extent Customer's total deliveries exceed Customer's total consumption at the end of a Billing Month, the excess volumes shall be added to the Customer's Balance Account. To the extent Customer's total consumption exceeds Customer's total deliveries at the end of a Billing Month, the shortfall volumes shall be subtracted from the Customer's Balance Account.

Balance Account Limits. At no time, as calculated at the end of a Billing Month, shall a Customer exceed a Balance Account excess or shortfall balance greater than 10% of the Customer's total scheduled deliveries for the month, as determined by the Company in its sole discretion. Any such imbalance over 10% (excess or shortfall) shall be subject to the Cash-in/Cash-out pricing set forth in Section 22.2 for monthly imbalance volumes in excess of 5%, with the remaining imbalance volumes to be carried over into the calculation of the Customer’s imbalance volumes for the following month. **(C)**

The Company, in its sole discretion, may zero out the Customer's Balance Account at the end of any Billing Month by purchasing or selling such net imbalance volumes in the Customer's Balance Account at the prevailing month's Cash-In/Cash-Out pricing at set forth in Section 22.2, provided such zero out may occur only if necessitated by operational needs of the Company or as a result of a requirement of an applicable interstate pipeline.

(C) Indicates Change

RATE MBS - Continued

MONTHLY BALANCING SERVICE

MONTHLY RATE TABLE

Monthly Transportation Volume

Rate DS/IS	$0.0177/Mcf x Monthly Billed Volumes	**(I)**
Rate LFD	$0.0103/Mcf x Monthly Billed Volumes	**(I)**
Rate XD	$0.0104/Mcf x Monthly Billed Volumes	**(I)**

The Company will update the average monthly imbalance utilized in the development of Rate MBS charges annually with the actual average monthly imbalance for the 12-month period ending September to determine the new Rate MBS charges effective December 1 each year. The Company shall include the new Rate MBS charges as part of its annual PGC compliance filing.

(I) Indicates Increase

RATE LFD

LARGE FIRM DELIVERY SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company. It is available to any Customer who executes a Service Agreement with the Company for an on system Daily Firm Requirement (DFR), as agreed to by Customer and Company in said agreement, for not less than fifty (50) MCF of gas per day of firm service. Volumes delivered under this Rate shall be metered separately from service under any of the Company's other rates, except as provided for in Rates IS, NNS, and MBS. In lieu of separate metering, the Company may accept contractual commitments specifying minimum volumes of service under Rate LFD.

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized receipt point, as determined by the Company in its sole discretion, provided Company has available on-system and/or pipeline capacity available in such quantities to meet Customer requirements. The Company shall be under no obligation to maintain on-system facilities required for service beyond the term of an executed service agreement.

Unless otherwise agreed by the Customer and Company, the Customer must enter into a Service Agreement for a minimum term of two (2) years. The Service Agreement shall continue in force for consecutive two (2) year periods unless cancelled by Customer upon one (1) year written notice to the Company prior to the expiration of the then current Service Agreement term. The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

Delivery Service shall be provided for all volumes provided by the Customer for which the Company has available delivery capacity, subject to the curtailment provisions of the Company's Tariff, applicable rules and regulations of the PUC and any other governmental mandates. **(C)**

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

The DFR shall be the Company's contracted maximum firm delivery obligation to the Customer on any day and shall be no less than fifty (50) MCF. Service in excess of the DFR is interruptible in accordance with the terms of Rate IS.

Service under Rate LFD is subject to the terms set forth under Section 22 - General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

(C) Indicates Change

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Demand Charge, the Capacity Charge (if applicable), the Distribution Charge and any Excess Take Charge as described below. The following are maximum rates.

Customer Charge: $670.00

Plus
Maximum Demand Charge: $7.6956/Mcf of Customer's elected DFR. **(I)**

Plus
Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected DFR. Applicable only when the customer elects UGI capacity.

Plus
Maximum Distribution Charge (all volumes): $1.3831/Mcf **(I,C)**

Plus
SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I - Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

RETAINAGE RATE

Company Use and Unaccounted for Gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j).

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

EXCESS TAKE CHARGE

Except as provided in the Company's *Nomination Procedure*, for authorized usage on any day in excess of the Daily Firm Requirement there will be a charge of $6.00 per MCF in addition to the charges specified in the rate table.

(I) Indicates Increase
(C) Indicates Change

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge, Demand Charge, Capacity Charge (if applicable), and Charge for Other Transportation.

Annual: The Minimum Annual Bill shall be based on the Customer maintaining a 0.50 annual load factor and shall be due and payable with the bill for the 12th month in the contract year. The Customer's actual load factor shall be determined by dividing the total volume of gas taken during the contract year (including volumes taken under the Retail and Standby Rider, and the Cash-Out provisions of Section 22.2) by the sum of the Daily Firm Requirements for the contract year. If the actual load factor is less than 0.50, then, in addition to payment for actual usage, the Customer shall pay a Minimum Annual Bill charge equal to the product of: (1) the difference between 0.50 and the actual load factor, (2) the sum of the Customer's Daily Firm Requirements for the contract year, and (3) the average delivery charge paid by the Customer over the previous 12-month period, as calculated by the Company. If the Customer's actual load factor is greater than or equal to 0.50, no Minimum Annual Bill charge will be required.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company. Such charges related to the use of Customer elected and Company provided transportation capacity shall be reflected directly on the Customer’s bill for service rendered on and after April 1, 2024, pursuant to Commission order at Docket R-2023-3040290, with such charges labeled on the bill as Capacity Charge.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Fifty Dollars($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Section 22.4 is primarily intended to establish applicable daily imbalance penalty charges but shall also provide for the pricing applicable to any Unauthorized Overrun volumes, which shall be subject to the same pricing as an Intentional imbalance. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun. **(I)** **(C)** **(C)**

SERVICE UNDER OTHER RATES

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purposes of determining Excess Take Charge and Unauthorized Overrun gas.

(C) Indicates Change (I) Indicates Increase

RATE XD

EXTENDED LARGE FIRM DELIVERY SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company on request of a Customer which the Company determines, in its sole discretion, has a prospective gas volume usage of at least 200,000 MCF per year at the time of execution or renewal of a Service Agreement.

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized receipt point, as determined by the Company in its sole discretion, provided Company has available on-system and/or pipeline capacity available in such quantities to meet Customer's requirements. The Company shall be under no obligation to maintain facilities required for service beyond the term of an executed Service Agreement.

Unless otherwise agreed to by the Customer and the Company, the Customer must enter into a service agreement for a minimum term of three (3) years. For a Customer requesting firm service, the Service Agreement shall specify an initial Daily Firm Requirement (DFR). The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

For Customers requesting firm service, Delivery Service shall be provided for all volumes provided by the Customer for which the Company has available delivery up to DFR, subject to the Section 21 – Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

Service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

The DFR shall be the Company's contracted maximum firm delivery obligation to the Customer on any day. Service in excess of the DFR is interruptible and will be provided under terms and conditions identical to those set forth under Rate Schedule IS.

Service under Rate XD is subject to the terms set forth under Section 22 - General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

RATE XD -Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be negotiable and shall be the sum of the Customer Charge, Distribution Charge, Demand Charge if applicable, the Capacity Charge (if applicable), and the Minimum Annual Bill as described below. **(C)**

The following are maximum rates.

Customer Charge: Charge as determined by negotiation.

Plus
Maximum Demand Charge: Charge as determined by negotiation.

Plus **(C)**
Capacity Charge: On or after October 28, 2025 when current Rate XD contracts expire, Capacity available for Customer use, and related Capacity Charge, shall be as specified within Customer's service contract, provided Company has available capacity and Company and Customer agree to related terms. For Customers electing Company capacity, such Capacity Charge shall be charged at the Company's unitized weighted average cost of firm transportation capacity per elected DFR. However, for Customers specifically receiving assignment of Columbia Pipeline capacity via agreement with the Company and through capacity release, such Customers, or their NGS, shall pay capacity charges direct to Columbia in accordance with such release. For Customers not receiving any Company capacity, no Capacity Charge will apply.

Plus
Maximum Average Delivery Charge: $1.3831/Mcf **(C,I)**

Plus
SURCHARGES and RIDERS

Rider I – Distribution System Improvement Charge

RETAINAGE RATE

Unless otherwise agreed between the Customer and the Company, Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j)

MINIMUM BILL

Minimum Bill Volumes and terms shall be defined in the Service Agreement and determined by negotiation.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the Customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

RATE XD - Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restrictions. If a Customer, after having received due notice of a restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Fifty Dollars($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing, whichever is greater, plus the charge specified in the monthly rate table. Section 22.4 is primarily intended to establish applicable daily imbalance penalty charges but shall also provide for the pricing applicable to any Unauthorized Overrun volumes, which shall be subject to the same pricing as an Intentional imbalance. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun. **(I)** **(C)**

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purpose of determining Unauthorized Overrun gas.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(C) Indicates Change (I) Indicates Increase

RATE R/S

RETAIL AND STANDBY RIDER

AVAILABILITY

Retail and Standby services are available under the Retail and Standby Rider to any Customer receiving service under Rate Schedules DS, LFD, XD and IS. Service shall be supplied only where the Company's facilities are suitable and available for the service desired. Service is subject to curtailment under Tariff Rule No. 21, Emergency Gas Planning.

Retail and Standby services under this schedule may be provided on a firm and/or interruptible basis. Subject to the Company's sole discretion, services shall be provided only if, and to the extent, sufficient Company and/or Customer provided capacity exists for the transportation of available gas supplies. Unless otherwise agreed by the Company and Customer, the Customer must enter into a service agreement for a minimum term of one (1) year with monthly payments for service taken.

The Company may provide capacity, supply or a bundled service, retail or standby, to the Customer under this rate schedule as per one or more of the following:
For Customers having upstream capacity rights: Company shall provide, or stand ready to provide, gas supplies to the Customer in such amounts and at such delivery or receipt points as necessary to meet Customers' contract requirements, as specified on a daily, monthly, seasonal or annual basis.

For Customers providing, selling or forwarding gas supplies to the Company for redelivery to Customer: Company shall provide, or stand ready to provide, pipeline and/or system capacity to deliver such gas supplies to the Customer.

For Customers requiring bundled sales service: Company shall provide, or stand ready to provide, the necessary pipeline and/or system capacity, and gas supplies necessary to provide gas service to the Customer at the Customers' metered location.

Where applicable, Customer must nominate standby service requirements by specifying a Nominated Standby Requirement (NSR) in MCF and a Daily Standby Requirement (DSR) in MCF per day of amounts equal to the Customer's total and daily standby supply requirements. Unless otherwise agreed by the Company and Customer, the firm or interruptible DSR shall be equal to the NSR divided by the number of days in the standby period.

Customers served under firm Rate Schedules DS, LFD, XD and IS may take firm retail and/or standby service under this rate schedule in any amount up to their available Daily Firm Requirement (DFR) or otherwise specified contract limit. All other terms and conditions of service as specified in Customer's Rate Schedules DS, LFD and XD and/or contract shall continue to apply.

Capacity and/or supply utilization under this rate schedule shall be on an as available basis for customers requesting retail and/or standby services. Subject to the Company's sole discretion, other incrementally obtained capacity and/or supply shall be assigned according to a Customer request queue or otherwise specified auction procedure. When necessary, such request queue or auction procedure shall be established in accordance with the terms outlined in the Company's *Nomination Procedure*.

The Company, upon notice to the Customer, may specify minimum levels of retail and/or standby nominations required for service under this rate schedule.

RATE R/S - Continued

RETAIL AND STANDBY RIDER

Service under Rate R/S is subject to the terms set forth in Section 22.2.

MONTHLY RATE TABLE

The charge for each Billing Month shall be the sum of the Customer Charge

Plus
The Capacity/Reservation Charge corresponding to the Customer's service election,

Plus
The Commodity Charge as shown below,

Plus
Administrative Service Fee: $75 per month.

Capacity/Reservation Charge:

Firm Retail Option: The applicable market price for available upstream capacity, plus the applicable charge for available system capacity, less any capacity charges paid under the Customer's applicable Rate Schedule, but in no case less than zero.

Firm Standby Option: The applicable Firm Standby Reservation Charge per MCF of DSR and/or per MCF of NSR.

a) The Firm Standby Reservation Charge shall be equal to the sum of the monthly contract demand rates charge by the Company's interstate pipeline suppliers divided by the sum of the daily contract demands.
b) The Firm Standby Reservation Charge shall be subject to increase or decrease whenever any of the Company's interstate pipeline suppliers make changes in their contract demand rates. Any change in the Standby Rate shall become effective on the first day of the month following the date on which the change in pipeline contract demand rate becomes effective.
c) The Firm Standby Reservation Charge revenues will be credited to the PGC.

Interruptible Standby Option: The applicable interruptible standby reservation charge per MCF of DSR and/or per MCF of NSR.

Plus

Commodity Charge: The distribution charge applicable under the Customer's Rate Schedule plus the applicable commodity cost, which shall be the identifiable additional cost of supply necessary to serve the Customer's usage, plus any applicable reservation cost of supply.

RATE R/S - Continued

RETAIL AND STANDBY RIDER

The minimum monthly bill under this rate schedule shall be the sum of the Customer and Capacity/Reservation Charges plus any commodity reservation costs per MCF of NSR.

SURCHARGES **(C)**

Rider I – Distribution System Improvement Charge

Any charges or penalties imposed by pipeline suppliers as a result of usage under this rider shall, at the Company's sole discretion, be allocated to Customers according to each Customer's contractual obligation or be assigned to the Customer responsible for the incurrence of the charges or penalties.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(C) Indicates Change

RATE IS

INTERRUPTIBLE SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company. It is available to any commercial or industrial Customer using gas for any purpose when Customer has executed a Service Agreement with a term of at least one (1) year for use of gas under the terms of this Tariff.

Service under this Rate shall only be provided when, in the Company's sole discretion, sufficient system capacity is available.

Unless otherwise agreed by both Customer and Company, service under Rate IS is available only to Customer loads with documented installed capability to consume an alternate fuel, and the Customer must enter into a Service Agreement for a minimum term of one (1) year with monthly payments for service taken. The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

The Customer and Company agree that a Manual Interruptible ("MI") Customer must maintain the ability to transfer the fuel source of its interruptible equipment from natural gas to an alternate fuel manually and demonstrate that they have the capability of consuming at least 5,000 MCF of gas annually. For all Automatic Temperature Control ("ATC") Customers, the Customer shall install and operate equipment to transfer the fuel source of its interruptible equipment from natural gas to an alternate fuel at a predetermined temperature setting as determined annually by the Company. **(C)** **(C)**

The Company shall verify, prior to commencement of service for new Customers that the customer load being served qualifies under these provisions. The Company shall be permitted to inspect the facilities and piping at the premises of the Customer from time to time to confirm that the load being served so qualifies. The Company, at its discretion, may require such separate metering and piping and elimination of any cross-connection to non-qualifying end use equipment as may be necessary to enforce these provisions and to ensure the interruption of service hereunder during periods of restricted service. It is the Customer's responsibility to ensure qualifying alternate fuel capability is maintained in good working order as Company shall maintain no obligation for service during periods of interruption. If the Customer fails to meet any of the applicable conditions listed below, as determined by the Company in its sole discretion, the Company may discontinue service or transfer the Customer to the otherwise applicable firm or standby rate schedule, provided sufficient on-system capacity is available:

1) ability to maintain qualified alternate fuel facilities
2) 24-hour notification capability
3) maintain operable ATC equipment

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized contract receipt point, as determined by the Company in its sole discretion and only when in the opinion of the Company there are sufficient facilities and gas supply. The Company maintains sole discretion to determine the appropriate allocation of gas to Customers.

(C) Indicates Change

RATE IS - Continued

INTERRUPTIBLE SERVICE

Gas service in excess of volumes delivered by the Customer shall be provided only in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

INTERRUPTION NOTIFICATION

MI Customers agree to maintain a twenty-four hour capability to receive notification of interruptions by the Company. When notified by the Company, the MI customer must discontinue use of natural gas for the Rate IS account until notification of Company to resume use of natural gas under Rate IS. Except in an emergency circumstance, the Company will provide reasonable notice of any interruption at least two hours prior, or upon written request of the Customer, if agreed by Company, of up to six hours.

ATC Customers agree to maintain equipment required to automatically switch fuels from natural gas to Customer's alternate fuel and from alternate fuel back to natural gas based on outside temperatures, as determined solely by the Company and noticed annually to the Customer. The ATC equipment shall meet specifications as provided by the Company and shall be in working order at all times from November through March of each year.

The Company reserves the right to periodically verify MI and ATC Customer's alternate fuel as well as to verify the proper operation of ATC equipment.

MONTHLY RATE TABLE

Customer Charge: Charge as negotiated between the Customer and the Company.

Plus,

Distribution Charge:
Charge as negotiated between the Customer and Company based upon the alternate fuels that the Customer has the economic capability of consuming, inclusive of related business factors.

MINIMUM ANNUAL BILL **(C)**

Shall be as negotiated by the Customer and Company and, unless the Company otherwise agrees, the Minimum Annual Bill shall be calculated at the end of any Service Agreement period, anniversary, or termination of service in accordance with terms of the Service Agreement. Volumes of natural gas taken under Standby Service during the Service Agreement period shall be credited to the Minimum Annual Bill volumes.

SURCHARGES and RIDERS

Rider I – Distribution System Improvement Charge

PAYMENT

In accordance with Section 8 of this Tariff.

(C) Indicates Change

RATE IS - Continued

INTERRUPTIBLE SERVICE

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then Customer shall be billed for such excess gas at the rate of Fifty Dollars ($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Section 22.4 is primarily intended to establish applicable daily imbalance penalty charges but shall also provide for the pricing applicable to any Unauthorized Overrun volumes, which shall be subject to the same pricing as an Intentional imbalance. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun. **(C)**

Gas delivered under the Rate IS or purchased under the Cash-Out provisions of Section 22.2 or the Retail and Standby Rider or taken under Rate NNS shall be included in the determination of Unauthorized Overrun gas.

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

(C) Indicates Change

UGI GAS EXHIBIT F – CURRENT TARIFF

GAS CHOICE SUPPLIER TARIFF - PA P.U.C. NO. 7S

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Aggregation Service

Issued: November 26, 2025

Effective for service rendered on and after December 1, 2025; filed in Compliance with the Order of the Pennsylvania Public Utility Commission, entered on September 25, 2025 at Docket No. R-2025-3054938.

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This supplement makes increases and changes to existing rates (see page 2b).

RULES AND REGULATIONS

1. THE CHOICE SUPPLIER TARIFF

1.1 Filing and Inspection. A copy of this Choice Supplier Tariff (Sections 1 – 11) (hereinafter "Supplier Tariff"), which includes the Charges and Rules and Regulations under which the Company will supply Aggregation Service to Company approved Natural Gas Suppliers (Choice Suppliers) serving customers under Rate Schedules RT and NT, is on file with the Pennsylvania Public Utility Commission and is available on the Company's website https://www.ugi.com/tariffs. (C)

1.2 Application. The provisions of the Supplier Tariff apply to all Choice Suppliers serving customers under Rate Schedules RT and NT.

1.3 Statement by Agents. No representative has authority to modify a Supplier Tariff rule or provision, or to bind the Company by any contrary promise or representation.

1.4 Rules and Regulations. The Rules and Regulations, as part of this Supplier Tariff, are a part of every Aggregation Agreement entered into by the Company pursuant to this Supplier.

1.5 Purpose of Tariff. This Supplier Tariff sets forth the basic requirements for interactions and coordination between the Company in its role as a Natural Gas Distribution Company (NGDC) and Choice Suppliers, and includes rules necessary for maintaining the delivery of gas to customers served under Rate Schedules RT and NT.

(C) Indicates Change

RULES AND REGULATIONS

2. CHOICE SUPPLIER QUALIFICATION

2.1 Service under this Tariff is contingent upon the Choice Supplier completing the Company's Choice Supplier Application Form to Serve Choice Customers (Application) and Company's approval of such Application. Choice Supplier shall include with its returned Application, payment of a non-refundable Enrollment Fee of five hundred dollars ($500). In the event the Choice Supplier submits an incomplete application, the Company shall provide written notice to the Choice Supplier of the Application's deficiencies. An incomplete Application will not be processed by the Company until it is fully completed by the Choice Supplier and received by the Company. Failure to submit a fully completed Application within thirty (30) calendar days following notice that the Application was incomplete will result in a rejection of the Application.

2.2 Choice Supplier must meet all pipeline credit standards and prove it is qualified by the pipeline to receive an assignment, release or transfer of pipeline capacity.

2.3 Processing of Application. The Company shall promptly process each Application and notify the Choice Supplier of the results of Company's review of such Application. If the Company rejects an application, the Company will provide a reason.

2.4 Approval of Application. Upon approval of Choice Supplier's Application, Company shall execute the duplicate originals of the Aggregation Agreement tendered by the Choice Supplier and return one copy to the Choice Supplier.

2.5 Supplemental Evaluations. Company may require additional periodic credit evaluations to ensure ongoing financial fitness as set forth in Section 8 of this Tariff. The Choice Supplier will be assessed a $250 fee for all credit evaluations performed by Company. The evaluation will be based on standard credit factors such as previous Choice Supplier's customer service record, Dun & Bradstreet or similar financial and credit ratings, trade references, bank information, unused line of credit, and financial information. Company shall have sole discretion to determine creditworthiness based on the above criteria but will not deny creditworthiness without reasonable cause.

2.6 A qualified Choice Supplier may opt to participate in the Purchase of Receivables ("POR") program offered by the Company by entering into a Purchase of Receivables Agreement. Upon approval of a Purchase of Receivables Agreement, the Company shall execute the duplicate originals of the Purchase of Receivables Agreement tendered by the Choice Supplier and return one copy to the Choice Supplier. A copy of the POR Agreement may be found on the Company's Energy Management website.

RULES AND REGULATIONS

3. CUSTOMER LIST

3.1 Customer Choice List. Company will maintain a list of Rate R, RT, N, and NT customers that have authorized the release of their information in a secure portion of a Web Site accessible to Choice suppliers in compliance with the requirements of Rule 3.2. When authorized by the customer, this list shall also include account number, address, rate code and / or historical usage.

3.2 Customer List Confidentiality. Such list shall only be accessible by Choice Suppliers that have executed a Confidentiality Agreement and are otherwise qualified to serve Rate RT and NT customers under this Tariff.

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.1 Unless otherwise authorized by Company, Choice Suppliers must comply with the provisions of Section 7 of the Choice Supplier Tariff.

4.2 A Choice Supplier must provide and maintain a bond or other financial guarantee in a form and amount as set forth in Section 8 that is acceptable to Company and/or other PUC-approved Supplier of Last Resort.

4.3 A Choice Supplier must acquire or agree to acquire an adequate supply of natural gas to serve Choice Supplier's Aggregation Pool and make or cause to be made arrangements by which such gas supplies can be transported to Company's city gates, as directed by Company. Such supplies must be ranked on the transporting pipeline at the pipeline's highest Predetermined Allocation ranking.

4.4 A Choice Supplier must enter into an Aggregation Agreement to serve Choice customers under Rate Schedules RT and NT.

4.5 A Choice Supplier must comply with Company system reliability requirements, including Daily Flow Directives (DFDs), Operational Flow Orders (OFOs), and notice requirements.

4.6 A Choice Supplier must comply with applicable communications standards, including approved internet based Electronic Data Interchange (EDI) procedures.

4.7 A Choice Supplier must cooperate with Company in the preparation of an annual reliability plan presented to the PUC.

4.8 A Choice Supplier must acquire and maintain a PUC license.

4.9 A Choice Supplier (including their nominating agents, if applicable) who nominates gas for delivery to the Company's system must have and maintain Internet access. The Choice Supplier shall also provide Company with a valid email address and 24-hour contact information.

4.10 The Company's provision of Aggregation Service is contingent upon the Choice Supplier paying all amounts billed to it by the Company in a timely manner.

4.11 Failure to comply with all Choice Supplier Obligations will result in the Company disqualifying the Choice Supplier from serving customers under Rate Schedules RT and NT. In the event the Company disqualifies a Choice Supplier, the Choice Supplier may appeal the disqualification to the PUC. If the PUC does not reverse the disqualification within 45 days, the Choice Supplier will be disqualified at the end of the 45-day period and its customers will be returned to sales service or switched to another Choice Supplier. Any Company disqualification will be on a non-discriminatory basis.

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.12 If a Choice Supplier elects to participate in the Company's POR Program, the Choice Supplier must enter into a POR Agreement for the rate classes that it serves that will be included in the POR. The elected Rate Classes shall be one of the following: (1) RT only, (2) NT only, or (3) RT and NT. All receivables associated with basic natural gas supply services in the specific rate class, subject to the rate class elections made above, must be sold by the participating Supplier to the Utility. For the purposes of this provision, the phrase "basic natural gas supply services" shall include charges directly related to the physical delivery of natural gas to a retail customer but shall not include charges for "carbon-neutral" products, appliance maintenance service, energy efficiency services, termination or cancellation fees, security deposits or other products or services not directly related to the physical delivery of natural gas to a retail customer. Customer accounts that are billed for non-basic natural gas supply services will not be eligible for UGI's POR program. All of the NGS' customer accounts within the elected Rate Classes (subject to the volumetric limits contained in section 5.4) must be POR eligible accounts, with the exception of customers that purchase carbon-neutral products. NGSs may choose to use UGI consolidated billing for Non-POR eligible customers who are purchasing bundled "carbon-neutral" product offerings. The termination and reconnection provisions of Chapters 14 and 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing. UGI shall support rate-ready billing, and all NGS rates must conform to supported rate designs. For Purchased Customer Accounts, Company shall pay Choice Supplier an amount equal to 97.30% for residential amounts billed (inclusive of associated sales taxes) and 99.30% of non-residential amounts billed (also inclusive of taxes). Customer participation for NT shall be subject to Volumetric Eligibility pursuant to Section 5.4. **(C)** **(C)** **(C)**

4.13 All existing customers of Choice Suppliers who elect to participate in the Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier and Company that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

All new customers enrolling with Choice Suppliers who are participating in Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier prior to enrollment, and by Company upon enrollment, that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

(C) Indicates Change

RULES AND REGULATIONS

5. OPERATIONAL REQUIREMENTS

5.1 Daily Delivery Requirements. The Company will communicate to each Choice Supplier a Daily Delivery Requirement (DDR). The DDR will be the required amount of gas to be delivered for the indicated date for each Choice Supplier's pool of customers served under Rate Schedules RT and NT and may specify the required points of delivery. The DDR includes a volume of gas that the Company will retain for Company use gas, and lost and unaccounted for gas, equal to 1.5% of total volume of gas delivered into its system for the Customer's account. Choice Suppliers who fail to deliver their DDR will be subject to penalties and imbalance charges as outlined in Rate AG. **(I)**

5.2 Daily Flow Directive. An order issued by the Company to address system management issues including actions necessary to comply with statutory directives and obligations. DFDs will be communicated to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. DFD notices shall include an explanation of the cause of the DFD. Customers and NGSs must provide the Company with a 24-hour contact for DFDs. Failure to comply with a DFD may result in the Customer or NGS being assessed the penalty charge set forth in Section 22.4 of the Company's Gas Service Tariff.

5.3 Operational Flow Orders. A directive issued by the Company that is reasonably necessary to alleviate conditions that threaten the operational integrity of the Company's system, including actions necessary to comply with statutory directives and obligations OFOs will be communicated as soon as reasonably practical to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. OFO notices shall include an explanation of the cause of the DFD. Customers and NGSs must provide the Company with a 24-hour contact for OFOs. Failure to comply with an OFO may result in the Customer or NGS being assessed the penalty charge set forth in Section 22.4 of the Company's Gas Service Tariff.

5.4 POR Volumetric Eligibility Requirements for Rate NT. All Rate NT Customers with annual usage of 1,000 Mcf or less will be eligible for inclusion into a POR program.

(I) Indicates Increase

RULES AND REGULATIONS

6. BILLING AND PAYMENT

6.1 Billing Period. On or before the 15th of a month, Company shall send each Choice Supplier an invoice reflecting all charges incurred by the Choice Supplier for the prior calendar month activities. Such invoice may include charges related to adjustments for prior periods.

6.2 Payment. Payments will be due 10 days following issuance of the invoice. Choice Supplier shall make payment to the Company of such invoiced amount by wire transfer to the bank and account specified on the invoice. If the invoiced amount is less than $1,000, payment can be made by check, payable to the Company. Unpaid balances shall accrue interest at the rate of 1.5 percent per month. Unpaid balances may result in the Company accessing the financial security posted by the Choice Supplier and / or the Choice Supplier being disqualified from providing Aggregation Service.

6.3 Billing Dispute. If Choice Supplier asserts a good faith billing dispute, the Choice Supplier shall inform the Company in writing of such dispute and pay the undisputed amount. The disputed amount shall accrue interest at the effective prime rate of interest as published under "Money Rates" by "The Wall Street Journal", or the maximum contract rate permitted by law, whichever is less. The Choice Supplier and the Company shall endeavor to resolve any disputes promptly and the amount determined to be properly invoiced, plus accrued interest on such amount shall be paid to the Company within fifteen (15) days following such resolution. Unpaid amounts not subject to dispute shall accrue interest at the rate specified in 6.2.

6.4 Licensed Supplier Budget Billing. The Company will bill all budget billing amounts calculated and provided by the Licensed Supplier. The Company will not determine a Licensed Supplier's budget bill charge unless the account is being billed under the POR program.

RULES AND REGULATIONS

7. NOMINATION PROCEDURE

7.1 Customer Choice Nomination Procedure. The Nomination Procedure specifies requirements for nominating, scheduling, balancing, and communicating information relating to Choice Supplier's gas deliveries for customers served under Rates RT and NT.

7.2 Contact Persons. A list of Company contact persons will be posted on the Company's Web Site, located at https://ugi.outsystemsenterprise.com/UGIContacts_FO/, or its successor, along with their department affiliation, email address, and telephone number.

7.3 Mandatory Assignment. As used in this tariff the term "Firm Commodity Supply Alternative" shall mean a Company purchase of natural gas, delivered directly to its distribution system or at points along Company pipeline capacity routes (Commodity Delivery Points), constituting a component of Company's PGC supply portfolio and an alternative to pipeline capacity contracts upstream of the Commodity Delivery Points or other firm sources of PGC supply. Firm Commodity Supply Alternative contractual arrangements may require the payment of demand charges or minimum take requirements. Except as provided below, Choice Supplier shall be required to accept releases of Company pipeline capacity combined with bundled city gate sales and, as applicable, peaking sales of gas from Company and sales of gas associated with Firm Commodity Supply Alternative arrangements, in accordance with the following assignments:

A monthly release of interstate pipeline capacity or allocation of Firm Commodity Supply Alternative in an amount equal to thirty-eight percent (38%) of the Peak Day Delivery Requirement ("PDDR") of the Choice Customers served by the Choice Supplier during the month shall be released or allocated at a price equal to the projected weighted average demand cost of all PGC capacity, storage, peaking and Firm Commodity Supply Alternative assets, divided by 0.255. Effective November 1, 2020, to the extent the full Firm Commodity Supply Alternative is not fully nominated by Choice Supplier to satisfy its DDR, the remaining daily quantity may be nominated to a non-Choice transportation customer or pool of non-Choice transportation customers. **(C)** **(C)**

The Company shall also provide Choice Suppliers with a must-take Monthly Bundled Sale Quantity ("MBSQ") during each winter month of November through March, and the Choice Supplier would be permitted to nominate and purchase gas at the Company's city gates throughout each winter month, subject to the Maximum Daily Quantity ("MDQ") limits, up to the MBSQ. The MDQ equals twenty-four percent (24%) of the PDDR of the Choice Customers served by the Choice Supplier during the month multiplied by the percentage shown on the Company's Energy Management website. The minimum daily quantity is zero. Choice Suppliers are required to nominate to the Company a daily quantity for bundled sales no later than 2:00 P.M. Eastern Prevailing Time on each Intercontinental Exchange ("ICE") trading day for deliveries applicable to the ICE flow dates. If no nomination is received, the nomination quantity would default to zero. The Company reserves the right to issue Operational Flow Orders ("OFO") that can modify the daily bundled sale MDQ or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. MBSQs would be based on the Company's storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier's pre-month normalized **(C)**

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

delivery requirements, which will be shown on the Company's Energy Management website.

If the full MBSQ is not nominated and purchased by the end of each such winter month, the shortfall ("Bundled Sale Cash-In quantity") would be purchased by the PGC ("Bundled Sale Cash-In amount") as follows:

~~a.~~ The DDR Variation Percentage is the sum of the actual DDRs experienced by a Choice Supplier divided by the sum of the pre-month average DDRs that was used to calculate the MBSQ, converted to a percentage. For any month where the DDR Variation Percentage is greater than ninety percent (90%), the Bundled Sale Cash-In amount would equal (1) the product of (a) 0.90 times the lowest absolute low for the Texas Eastern, M-2 receipts Reference Price as published in DPP for the applicable month of flow minus (b) the summer Reference Price used for bundled sales (the "Bundled Sale Cash-In Reference Price") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier. **(C)**

b. In recognition of the effects of extreme warm weather conditions, shortfall amounts would be purchased as follows under such conditions:

i. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent(90%) and (b) the Bundled Sale Cash-In quantity is less than or equal to the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the First of the Month Price called "Columbia Gas Transmission Corp., Appalachia" as published in the MPP for the month subsequent to the applicable month in which the Bundled Sale Cash-In quantity was created minus the summer Reference Price used for bundled sales (the "Alternate Bundled Sale Cash-In Reference Price") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier. **(C)**

ii. For any month where (a) the DDR Variation Percentage is less than or equal ninety percent (90%) and (b) the Bundled Sale Cash-In quantity is greater than the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the Alternate Bundled Sale Cash-In Reference Price, as defined in Section 7.3.b.i, times the DDR Variation Percentage times the MBSQ plus(2) the Bundled Sale Cash-In Reference Price, as defined in Section 7.3.a,times the difference of the Bundled Sale Cash-In quantity minus the product of the DDR Variation Percentage times the MBSQ. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

In addition to the bundled sales described above, Choice Suppliers shall be required to purchase from Company a separate bundled sale on peak days ("Peaking Sale") equal to an amount up to thirty-eight percent (38%) of the PDDR of the Choice Customers served by the Choice Supplier during the month. The Peaking Sale would be made on winter days when the Choice Supplier's DDR exceeds the sum of the released firm capacity and the MDQ associated with the bundled sale. The Peaking Sale quantity would be the difference of the Choice Supplier's DDR minus the sum of the released firm capacity and the MDQ associated with the bundled sale. The Peaking Sale price would be based on the commodity cost of the Company's peaking services. If weather conditions cause the Choice Supplier's DDR to exceed the Choice Supplier's PDDR, the Choice Supplier would be responsible for arranging for supplies to meet the additional delivery requirements for its Choice Customers. **(C)**

Also in addition to the bundled sales described above, to the extent Company's design cold PGC supply portfolio includes Firm Commodity Supply Alternative contractual arrangements containing minimum take requirements, Choice Supplier shall also be required to make monthly purchases of natural gas from Company in an amount and at the commodity price Company would have been required to pay under the Firm Commodity Supply Alternative contractual arrangements had the Choice Customers projected to be served by the Choice Supplier during the month received PGC service. To the extent Company's design cold PGC supply portfolio includes Firm Commodity Supply Alternative contractual arrangements not containing minimum take requirements, Choice Supplier may elect on a month-to-month basis to make monthly bundled city gate purchases of natural gas from Company in an amount and at the commodity price Company would have been required to pay had the Choice Customers projected to be served by the Choice Supplier during the month received PGC service, provided, however, that nothing in this section shall preclude the Company from issuing OFOs requiring additional purchases of natural gas in accordance with the provisions of Section 5.3 of this tariff.

7.4 Capacity Recall. All capacity assigned, released or transferred by Company is subject to recall, or in the event:

a. A Choice Supplier is disqualified as an approved Choice Supplier on Company's system; or

b. The amount of capacity assigned, release or otherwise transferred is no longer required to serve the Choice Supplier's Pool; or

c. The Choice Supplier fails to comply with Section 4 of this tariff (Supplier Obligations) and the capacity is required by the Company or PUC approved Supplier of Last Resort to meet its firm commitments; or

d. The capacity is needed to protect the Company's gas distribution system integrity or meet the Company's public utility obligations.

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

7.5 Agents. A Choice Supplier may have one or more agents who perform one or more supply obligations under this Supplier Tariff. In the event such an agent or agents are utilized, Choice Supplier shall notify Company of the responsibilities of the Agent and shall provide Company with the Agent's valid e-mail address, 24-hour contact, and phone number for contact purpose. Choice Suppliers using Agents shall remain liable for all charges and penalties.

7.6 Determination of Capacity Assignment Quantities. Assignments, releases or transfers of upstream pipeline firm transportation capacity made pursuant to Section 7.3 shall be made on the basis of and in accordance with the supply portfolio held by Company at the time of assignment and the composition of the Choice Supplier's Pool. Each month the Company will evaluate and adjust the capacity releases quantity made to the Choice Supplier from time to time, as required.

7.7 City Gate Receipt Points. For nomination purposes, all transportation volumes received on behalf of customers served under Rates RT and NT shall be nominated to the Company's City Gate receipt points. Company reserves the right to specify delivery receipt points.

7.8 Daily Nominations. Choice Suppliers serving Rate RT and NT customers shall submit daily nominations equal to the DDR, consistent with the Company's requirements.

7.9 Third Party Supply Nominations - Customer Consent. All Company Choice Customers must provide consent to any Choice Supplier nominating on their behalf. Enrollments by Choice Suppliers are deemed to constitute that the customer has provided such consent. For transportation customers served under Rates RT and NT the Choice Supplier must maintain and produce upon request by Company evidence of customer consent within one business day notice.

RULES AND REGULATIONS

8. FINANCIAL SECURITY

8.1 Financial Security. A Choice Supplier shall provide financial security to ensure that Company and/or other PUC-approved Supplier of Last Resort is able to receive, without undue delay, funds or other forms of remuneration sufficient to meet the financial consequences of a Choice Supplier's failure to perform its natural gas supply delivery service obligations hereunder. Company may also use such forms of financial security to satisfy in part or in whole a Choice Supplier's obligation to pay the penalties authorized by this Supplier Tariff. The amount and the form of the security, if not mutually agreed upon by the Company and the Choice Supplier, shall be based on the criteria established under 52 Pa. Code § 62.111(c) and as set forth in this Section 8.

8.2 Amount of Financial Security. A Choice Supplier seeking to be licensed to provide service on the Company's system shall be required to provide 1) a minimum surety level of $50,000 or 2), if higher, the sum of the surety level requirements calculated on a customer basis equal to (i)$60.00 per customer for residential customers; and ii)$94.24/Dth times the Design Day Requirement (in Dth) for Choice Supplier's pool of non-residential customers. This security level shall be subject to adjustments as provided in Section 8.5. Provided, however, the Company reserves its right to file to change that methodology after the effective date of new rates established in the proceeding if the security levels prove inadequate.

8.3 Forms of Financial Security. For purposes of satisfying the amount of financial security determined under Section 8.2 hereof, the Choice Supplier shall provide financial security in one or more of the following manners, in a form reasonably acceptable to the Company and/or other PUC-approved Supplier of Last Resort, and shall reimburse Company for attorneys' fees and all related external costs incurred by Company in implementing and enforcing the form of financial security provided by Choice Supplier:

(a) cash;

(b) performance bond;

(c) irrevocable letter of credit;

(d) guarantee from a third party;

(e) call options satisfying the requirements of Section 8.4 hereof;

(f) in the case of Choice Suppliers with annual operating revenues of less than $1 million; real or personal property placed in escrow or other arrangement that would make the property readily available to Company in the event of the Choice Supplier's non-performance or entering into bankruptcy, provided that the Choice Supplier (i) provides a verified statement, certified by a third party report, showing that the Choice Supplier has clear title to the property and that the property has not been pledged as collateral, or otherwise encumbered in regard to any other legal or financial transaction; (ii) provides a current appraisal report of the market value of the property; and (iii) grant the Company, upon request, a security interest in such property in a form acceptable to Company;

(g) accounts receivable pledged or assigned to the Company pursuant to a Company PUC-approved POR program satisfying the requirements of Section 8.6 hereof; or

RULES AND REGULATIONS

8. FINANCIAL SECURITY – CONTINUED

(h) another form of financial security mutually acceptable to Company and Choice Supplier.

8.4 Call Option Requirements. A Choice Supplier may meet some or all of its financial security obligations determined under Section 8.2 hereof by providing to Company or paying the Company to procure a Call Option for a volume equal to the monthly Design Day Requirements of the Choice Supplier's customers served under Rate Schedules RT and NT. Unless otherwise authorized by Company, the Call Option must have a strike price equal to or less than the Choice Supplier's contract price(s) with its customers served under Rate Schedules RT and NT. The Call Option shall allow Choice Supplier or Company to call on a volume equal to the Choice Supplier's Design Day Requirement on each and every day the Call Option is in place such that the exercise on any day does not preclude or impact the ability to exercise the option on a subsequent day. Call Options shall be subject to the following requirements:

(a) If procured by Choice Supplier, the Call Option must enable Company to exercise the Call Option in the event of non-performance by the Choice Supplier without obtaining the prior consent of Choice Supplier;

(b) If procured by Choice Supplier, the Call Option may be exercised by it for any reason, including economic reasons, on any day when Company and/or other PUC-approved supplier of last resort does not need to exercise it because of Choice Supplier's failure to perform its natural gas supply delivery service obligations hereunder;

(c) Company shall specify the period over which the Call Option may be exercised;

(d) The Call Option may be a direct NYMEX instrument, or it may be obtained indirectly from a third party. If the Call Option is a direct NYMEX instrument, the Choice Supplier shall assign the applicable capacity to Company. If the Call Option is obtained indirectly from a third party, then the transaction point shall be at a Company-approved city gate receipt point; and

(e) Choice Supplier shall be responsible for the cost of the Call Option.

8.5 Adjustments to Financial Security Level. From time to time, the Company shall review the financial security provided by a Choice Supplier and determine whether any adjustments are required consistent with the formula under Section 8.2 hereof. The Company shall use the following factors to determine whether any such adjustments are required:

(a) A change in the Choice Supplier's recent operating history on Company's system or on other NGDS systems has materially affected Company system operation or reliability. A change that could materially affect the Company system or reliability may occur when the Choice Supplier fails to deliver natural gas supply sufficient to meet its customers' needs on 5 separate occasions within a 30-day period or fails to comply with Company Operational Flow Orders as defined at 52 Pa. Code § 69.11.

RULES AND REGULATIONS

8. FINANCIAL SECURITY - CONTINUED

(b) A significant change in the number of customers served, in the volume of gas delivered, or in the unit price of natural gas or a change in the class of customers being served by the Choice Supplier. A change over a consecutive 30-day period of 25% in the number of customers served, in the volume of gas delivered or in the average unit price of natural gas would represent a significant change.

(c) A change in the Choice Supplier's credit reports that materially affects the Choice Supplier's creditworthiness. A Choice Supplier's creditworthiness could be materially affected when two of the following credit rating companies change the Choice Supplier's credit rating: Dun & Bradstreet, Standard & Poor's Rating Services, Inc., TransUnion LLC, EQUIFAX Inc., Experian Information Solutions, Inc.

(d) A change in operational or financial circumstances that materially affects the Choice Suppliers' creditworthiness. A Choice Supplier's creditworthiness could be materially affected when two of the following investment rating companies change the Choice Supplier's rating of its issued securities from an investment grade or good rating to a speculative or moderate credit risk rating, and vice versa: Standard and Poor's Rating Services, Inc., Moody's Investment Services, Inc., Fitch, Inc., A.M. Best Company, Inc. and DBRS, Inc.

8.6 POR Requirements. A Choice Supplier may meet part or all of its financial security obligations determined under Section 8.2 hereof utilizing the accounts receivable pledged or assigned to the Company pursuant to a Company PUC-approved POR program, provided that Choice Supplier executes a Security Agreement which, among other things: (a) grants Company a first priority security interest in the accounts payable to Choice Supplier for the purchased receivables; and (b) grants Company an immediate right of set off against any account payable to Choice Supplier for any obligation owed by Choice Supplier to Company.

To reflect the variability in the amounts owed by Company to Choice Supplier for purchased receivables given seasonal variations in customer loads, the amount of this form of security will be determined pursuant to the following formula: (The average daily Mcf volume of gas delivered by the Choice Supplier during the lowest 30 day period of volume during the past 12 months for accounts enrolled in the POR program) times (the lowest rate per Mcf charged by the Choice Supplier during the past 12 months) times (the number of days between the purchase of and payment for a Choice Supplier's receivables).

8.7 Notice. If the Company determines, based on the criteria in Section 8.5 hereof, that an adjustment in the amount or type of security that a Choice Supplier must provide is warranted, the Company shall provide notice of its determination to the Choice Supplier in writing. The Choice Supplier shall comply with the Company's determination no later than 5 business days after the date the Choice Supplier was served with notice of the Company's determination. If the Choice Supplier disagrees with the Company's determination, the Choice Supplier may file a dispute with the Company, and the Company and the Choice Supplier must attempt to resolve the dispute within 30 days after the date that the Company was notified of the dispute.

RULES AND REGULATIONS

9. ENROLLMENT OF CUSTOMERS INTO RATE SCHEDULES RT AND NT

9.1 To be served under Rate Schedules RT and NT, a Customer must be enrolled by the Choice Supplier elected by the Customer. Such enrollment by the Choice Supplier must be provided in an electronic file to the Company via an approved internet-based EDI transaction. The requirement filed shall include:

a. The customer's name;
b. The customer's address;
c. The customer's Company account number;
d. The specific transaction;
e. The elected billing option.

9.2 Company Confirmation. Company will electronically confirm receipt of the enrollment information and within one (1) business day and subsequently provide an electronic validation of the Choice Supplier's transmitted information.

9.3 Determination of Gas Flow Date. For enrollments received and processed on or before the 15th of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company's mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer's regularly scheduled meter reading date in the calendar month immediately following the month the enrollment information was received and processed. For enrollments received and processed after the 15th of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company's mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer's regularly scheduled meter reading date in the second calendar month following the month the enrollment information was received and processed. **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS

10. RATE AG - AGGREGATION SERVICE

AVAILABILITY

Rate AG - Aggregation Service (AG Service) is available to and required for an approved Natural Gas Supplier (Choice Supplier) licensed by the PUC to provide natural gas supply service to customers who qualify to receive service under Rate RT (General Service - Residential Transportation) or Rate NT (General Service - Non-residential Transportation)(hereinafter a Choice Supplier).

AGGREGATION SERVICE

A Choice Supplier qualified to receive Rate AG Aggregation Service shall aggregate the load of customers served under Rates RT and NT customers in an Aggregation Pool. Such Aggregation Pool is limited to customers served under Rates RT and NT.

ASSIGNMENT OF COMPANY PIPELINE CAPACITY

Company has the right to require the Choice Supplier to accept a release, assignment or transfer of Company pipeline capacity on a recallable basis. The minimum such assignment shall be is one (1) Dth per day per pipeline path.

RATE TABLE

Balancing Fee for Choice Supplier ($/MCF) – As posted.

(Total Cost of Pipeline Assets Retained by Company for System Balancing - Balancing Related PGC Credits) divided by (Projected Annual Sales and Transportation Volumes Utilizing the Assets, as projected in each annual 1307(f) filing). This rate will be posted on Company’s Delivery Service Web Site or its successor and will be updated as required.

Pipeline Capacity and Bundled Sales:
Choice Supplier shall be responsible for applicable charges pursuant to Section 7.

RULES AND REGULATIONS

10. RATE AG – AGGREGATION SERVICE - CONTINUED

PENALTIES

Failure to Deliver DDR: **(C)**
The difference in price between the highest published Reference Price for the Texas Eastern, M-3 and the lowest published Reference Price for Texas Eastern, M-2 as published in the DPP corresponding to the date the failure to deliver occurred, plus the applicable transportation charges from Texas Eastern M-2 to M-3, but shall not be lower than $0.25/per Dth, applied to the difference between the DDR and the delivered volumes, plus all incremental costs incurred by Company as a result of the failure to deliver the DDR.

The Company may not charge for delivering in excess or under of the DDR if the overdelivery or underdelivery is anticipated to benefit the distribution system's daily balancing position as determined by Company in its sole discretion.

Failure to Comply with an OFO or DFD:
The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Fifty Dollars ($50) per Dth or the highest of the charges calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge for any delivery region, whichever is greater.

NOTICE

A Choice Supplier must provide Company, or any PUC-authorized alternative Supplier of Last Resort and its Rate RT and NT Customer(s) with ninety (90) days advance written notice of its intention to exit the market. In the event a Choice Supplier discontinues service or exits the market before its contract for natural gas supply service to a Rate RT and NT Customer expires and such Customer returns to its Supplier of Last Resort, Choice Supplier shall provide all contract billing data required by Company or other PUC-approved Supplier of Last Resort to render bills to Choice Supplier's customers for the period between Choice Supplier's default or exit from the market and the customer's next meter reading date.

BALANCING

Company will balance the daily difference, if any, between the anticipated Customer use, as communicated through the DDR, and the actual usage of Choice Supplier's customers. For this service, the Choice Supplier shall pay to Company the applicable Balancing Fees shown in this rate schedule, per MCF of Aggregation Pool usage, as measured at the meter.

(C) Indicates Change

RULES AND REGULATIONS

10. RATE AG - AGGREGATION SERVICE – CONTINUED

RECONCILIATION

Company shall calculate the difference between the actual deliveries of each Choice Supplier's Aggregation Pool, and the usage of each such Aggregation Pool. The Company shall adjust future DDRs to account for any usage differences between forecasted weather and actual weather. Where actual meter reads cannot be obtained, the Company will estimate usage and such estimate shall be deemed actual usage. At the time a Choice Supplier no longer has any Choice Customers enrolled, the cumulative difference between delivered volumes and usage of the Choice Supplier's Aggregation Pool shall be cashed out at Company's average cost of gas purchased for the most recent 12 months. The average cost of gas shall be calculated as the product of the total commodity cost of gas purchases including transportation and fuel used and accounted for the most recent 12 months, divided by tariff sales for the same 12-month period.

NATURAL GAS SUPPLY PLANS

Choice Supplier shall cooperate with Company in the preparation of such reliability plans required under Section 1317 of the Public Utility Code, and shall provide all reasonable information related to gas deliverability assets under its control required by Company including providing copies of pipeline capacity contracts or delivered supply contracts, or, in lieu of providing such contracts, warrant pertinent information as required by the Company or any regulatory authority. Choice Supplier shall also enter into any necessary contractual arrangements, or make any required regulatory filings, to ensure that contracts and assets under its control, which are relied upon in Company's reliability plan, are available to Company or PUC-authorized supplier of last resort in accordance with Choice Supplier's obligations under its Aggregation Agreement and this Tariff.

COMPLIANCE WITH THE PENNSYLVANIA PUBLIC UTILITY COMMISSION REQUIREMENTS

Choice Supplier shall at all times comply with all applicable PUC requirements and regulations.

UGI UTILITIES, INC.- GAS DIVISION **(C)**

11. AGGREGATION AGREEMENT

FOR RATE SCHEDULES RT and NT

(Pro Forma)

THIS AGGREGATION AGREEMENT for Rate Schedules RT and NT ("Aggregation Agreement") is made and entered into this _____ day of _____, 20___, by and between **UGI Utilities, Inc. – Gas Division**, a Pennsylvania Corporation ("Company"), and _____ _____, a _____ ("Choice Supplier").

WHEREAS, Company is a Pennsylvania public utility that, amongst other things, provides intrastate transportation service to Rate RT and NT customers located within its certificated service territory; and

WHEREAS, Choice Supplier is engaged in the business of selling natural gas supply services, and desires to market such services to Rate RT and NT customers located within Company's certificated service territory; and

WHEREAS, pursuant to the terms and conditions set forth in this Aggregation Agreement, Company is willing to receive natural gas supplies at specified points of interconnection situated between Company's facilities and the facilities of one or more interstate natural gas pipeline companies to serve the aggregated load of Rate RT and NT customers served by Choice Supplier, and to provide other services to facilitate the provision by Choice Supplier of natural gas supply services to customers; and

WHEREAS, pursuant to the terms and conditions set forth in this Aggregation Agreement, Choice Supplier is willing to deliver natural gas supplies for receipt by Company for subsequent transportation and redelivery at specified end-use customer locations, and to acquire aggregation services from Company.

NOW, THEREFORE, intending to be legally bound hereby, Company and Choice Supplier agree as follows:

ARTICLE I. DEFINITIONS

For the purposes of this Aggregation Agreement, in addition to any definitions set forth in Company's Gas Service Tariff and *Nomination Procedure* (which is available on UGI's Energy Management Website), which are hereby incorporated herein by reference, the following definitions apply: **(C)**

1.1. **Aggregation Service** means services provided by Company to Choice Supplier to facilitate the delivery of gas supplies to customers receiving service under Rates RT and NT. **(C)**

1.2. **Balancing** means services provided by Company to cover differences between a Choice Supplier's Daily Delivery Requirement and the actual usage of the Choice Supplier's Aggregation Pool. **(C)**

1.3. **Choice Aggregator** means an entity, licensed by the Commission, that purchases natural gas and takes title to it as an intermediary for sale to retail customers (52 Pa. Code § 62.101). **(C)**

(C) Indicates Change

1.4. **Choice Broker** means an entity, licensed by the Pennsylvania Public Utility Commission, that acts as an agent or intermediary in the sale and purchase of natural gas that does not take title to natural gas supply (52 Pa. Code § 62.101). **(C)**

1.5. **Choice Natural Gas Supplier (NGS)/Licensed Supplier** means a natural gas supplier as defined in 52 Pa. Code § 62.101, 66 Pa.C.S. § 2202, respectively. **(C)**

1.6. **Customer** means a recipient of service under Rate Schedules RT and NT that contracts for natural gas supply service from a Choice Supplier. **(C)**

1.7. **Daily Delivery Requirement (DDR)** means the daily quantities of natural gas supplies a Choice Supplier is required to deliver for an Aggregation Pool, as forecasted and communicated by Company, and may specify the required points of delivery. Such forecast shall be calculated to include volumes needed for end-use requirements, prior imbalances and Company use and unaccounted for gas. **(C)**

1.8. **Delivery Point** means a point specified by Company where Choice Supplier may deliver natural gas supplies for subsequent redelivery by Company to Choice Supplier's Rate RT and NT customers. **(C)**

1.9. **Rate Ready Billing** means the method of billing used by the Company to calculate the natural gas supply services provided by the Choice Supplier. Under this method, the Company uses actual meter readings obtained by the Company, or estimated consumption when the Company is unable to obtain an actual meter reading, and billing rate information provided by the Choice Supplier to calculate the bill. **(C)**

1.10. **Transportation** means a service provided by Company on its facilities that enables gas owned by others to be received into, moved through, and delivered out of facilities owned, leased, or operated and controlled by Company. **(C)**

1.11. **Upstream Capacity Assignment, Release or Transfer** means the process to provide access to interstate pipeline capacity and storage contracts owned by Company to Choice Supplier pursuant to Company's tariff and any applicable regulatory rules. **(C)**

ARTICLE II. TERM

This Aggregation Agreement shall become effective on _____, 20___ and shall remain in effect, unless terminated pursuant to Section 6.1 hereof, or by either party by providing ninety (90) days' prior written notice, for so long as Choice Supplier is qualified to receive Rate AG service from Company. In the event this Aggregation Agreement expires or terminates, Company shall have no obligation, as between Choice Supplier and Company, to accept any natural gas supplies tendered by Choice Supplier for receipt into Company's facilities, and Choice Supplier's payment and financial obligations shall continue until fully discharged.

ARTICLE III. CHOICE SUPPLIER'S OBLIGATIONS

3.1. **Compliance.** Choice Supplier agrees that it shall comply with all of the applicable terms and conditions of Company's Gas Service Tariff and Company's Supplier Tariff, both of which are hereby incorporated by reference. **(C)**

(C) Indicates Change

3.2. **Creditworthiness**. Choice Supplier shall establish, and maintain throughout the term of this Aggregation Agreement, and thereafter until all of Choice Supplier's payment obligations incurred under this Aggregation Agreement have been fully discharged, a satisfactory Financial Security status with Company. To enable the Company to determine credit status, Choice Supplier will provide to the Company the following: (1) relevant financial information to determine creditworthiness; (2) appropriate trade and banking references; and (3) written consent for Company to conduct a credit investigation. In addition, Choice Supplier shall comply with the Financial Security provisions of Company's Supplier Tariff, and may, based on Choice Supplier's credit standing with Company, be required to provide financial security in excess of the minimum amounts specified therein. **(C)**

3.3. **Standards of Conduct**. Choice Supplier shall abide by all standards of conduct and other legal requirements applicable to Choice Supplier's line of business, including but not limited to the standard of conduct applicable to Choice Suppliers set forth in rules and regulations established by regulatory bodies having jurisdiction over Choice Supplier's activities, and other applicable law. **(C)**

3.4. **Payments**. Choice Supplier will remit payment for all services within 10 days after receipt of Company invoice. A late payment charge of 1.50% per month will be applied to all outstanding balances as of the due date. **(C)**

3.5. **Customer List**. Choice Supplier shall execute an Electronic Trading Partner Agreement and will keep confidential any customer information acquired either directly or indirectly from Company, and use such information solely for the purpose of offering natural gas supply service to Rate RT and NT customers. In the event the Company determines the Choice Supplier impermissibly released customer information to another party, in addition to all available remedies, Company may, at its option, immediately cancel this Aggregation Agreement. **(C)**

ARTICLE IV. COMPANY'S OBLIGATIONS

4.1. **DDR**. Company shall provide Choice Supplier with its DDR for each Gas Day. Company shall accept receipt of all gas volumes up to the DDR. Company shall have the right to accept, but shall in no instance be required to accept, an Over-delivery by Choice Supplier. The acceptance of such over delivery shall not constitute any waiver of any provisions of the Company's Gas Service Tariff or *Nomination Procedure*. **(C)**

4.2. **Monthly Statement**. Company shall bill Choice Supplier by the 15th of each month for services provided by Company during the preceding month and other amounts due to Company. **(C)**

4.3. **Enrollment Notification**. Company shall generate and send a letter to all customers enrolled by a Choice Supplier indicating the supplier selected and the date service from the Choice Supplier is scheduled to commence. All customers enrolled by the 15th of each month will be transferred to their respective Choice Supplier effective with their next calendar meter read if customer does not respond within five (5) days following confirmation to challenge the enrollment. Company shall send an electronic message confirming the selection to the Choice Supplier. **(C)**

4.4. **Rate AG**. Company shall provide all of the other aggregation services applicable to Choice Supplier specified in the Rate AG provisions of its tariff. **(C)**

(C) Indicates Change

ARTICLE V. BILLING SERVICE

(C)

5.1. **Standard Billing Service.** Company shall bill Choice Supplier's Rate RT and NT customers for natural gas supply services provided by Choice Supplier on a rate-ready basis unless (a) a Choice Supplier not participating in the Company's POR program elects to provide a separate bill for its charges or (b) a Choice Supplier's customer elects to receive a separate bill for such services from its Choice Supplier. Choice Supplier must provide all billing rate information no later than fifteen (15) days prior to the effective date of such rate. Company will input all requests for new plans within a reasonable time frame based on the number of requests received.

5.2. **Standard Billing Charges.** Choice Supplier shall pay to Company the following fees for billing services:

Billing Fee:	$0.25/Bill
Billing Adjustment Fee:	Affecting One (1) Month - $3.10/Revised Bill
	Affecting More than One (1) Month - $3.60/Revised Bill

5.3. **Negotiated Billing Service.** In the event a Choice Supplier wants Company to provide a billing service other than the Standard Billing Service, such service shall be negotiated between Company and Choice Supplier.

5.4. **Choice Supplier Budget Billing.** The Company will bill all budget billing amounts calculated and provided by the Choice Supplier unless the account is being billed under the POR program, in which case the Company will provide budget billing to the customer. The Company will not determine or reconcile a Licensed Supplier's budget bill charge if the Licensed Supplier is not participating in the Company's POR program.

ARTICLE VI. REMEDIES

6.1. **Termination Upon Default.** In addition to other rights a party may have under this Aggregation Agreement, if either party fails to perform an obligation, or breaches any representation or warranty ("Defaulting Party") under this Agreement, then the other party (Non-Defaulting Party") shall have the right to terminate this Agreement by providing prior written notice thereof to the Defaulting Party. Termination pursuant to this Article shall be without waiver of any additional remedy, whether at law or in equity, to which the party not in default otherwise may be entitled for breach of this Agreement.

6.2. **Limitation of Liability.** Except as expressly permitted under this Agreement and Company's Gas Service Tariff, neither party shall be entitled to recover incidental, consequential or punitive damages, or lost profits, for any breach by the other party of an obligation, representation or warranty under this Agreement, provided such limitation shall not apply to willful or grossly negligent misconduct on the part of the Defaulting Party.

ARTICLE VII. REPRESENTATIONS, WARRANTIES AND INDEMNIFICATION

Choice Supplier warrants that (1) it shall have good title to all natural gas tendered for receipt by Company hereunder, or is authorized by the owner of such gas to tender it for delivery to Company, and (2) such gas will be free and clear of all liens, encumbrances, and claims whatsoever. Choice Supplier shall fully indemnify Company, and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of a breach of such warranties.

(C) Indicates Change

(C)

ARTICLE VIII. LIMITATION OF THIRD PARTY RIGHTS

This Agreement is entered into solely for the benefit of the Company and the Choice Supplier, and is not intended and should not be deemed to vest any rights, privileges or interests of any kind or nature to any third party, including, but not limited to the Customers that comprise Choice Supplier's Pool under this Agreement.

ARTICLE IX. SUCCESSION AND ASSIGNMENT

This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the respective parties hereto. However, no assignment of this Agreement, in whole or in part, will be made without the prior written approval of the non-assigning party. The written consent to assignment shall not be unreasonably withheld.

ARTICLE X. APPLICABLE LAW AND REGULATIONS

This Agreement shall be construed under the laws of the State of Pennsylvania and shall be subject to all valid applicable State, Federal and local laws, rules, orders, and regulations. Nothing herein shall be construed as divesting or attempting to divest any regulatory body of any of its rights, jurisdiction, powers or authority conferred by law.

ARTICLE XI. NOTICES AND CORRESPONDENCE

Written notice and correspondence to Company shall be addressed as follows:

UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517
Attention: Manager, Tariff & Supplier Administration
Email: EDI-GAS@UGI.COM

Written notices and correspondence to Choice Supplier shall be addressed as follows:

Name: _____

Address: _____

_____

Attention: _____

Telephone: _____

Email: _____

Either party may change its address for receiving notices effective upon receipt, by written notice to the other party.

ARTICLE XII. MISCELLANEOUS

12.1. No modification of the terms and provisions of this Agreement shall be or become effective except by execution of written contracts or by modification of Company's Gas Service Tariff.

(C) Indicates Change

(C)

12.2. No waiver by any party of any one of more defaults by any other party of any provisions of this Agreement shall operate or be construed as a waiver of any subsequent or previous default or default, whether of a like or a different character.

12.3. In the event any tax or assessment is imposed, directly or indirectly, upon the gas tendered to, or received by Company for redelivery, Choice Supplier agrees to bear the amount of such tax or assessment. In the event that Company is required to pay such tax, Choice Supplier agrees to reimburse Company for such payment.

12.4. The subject heading of the articles of this Agreement are inserted for the purpose of convenient reference and are not intended to be a part of the Agreement nor considered in any interpretation of the same.

12.5. In the event of a conflict between the provisions of this Agreement and Company's Gas Service Tariff, the provisions of Company's Gas Service Tariff shall govern.

12.6. This Agreement may be executed in multiple counterparts, each of which shall be deemed an original, and all of which together shall constitute one and the same instrument. The delivery of an executed counterpart of this Agreement by e-mail delivery of a ".pdf" format data file shall be deemed to be valid delivery thereof. The parties to this agreement agree to execution of this agreement by electronic means pursuant to the Electronic Transactions Act, 73 P.S. § 2260.101 et seq. Each party agrees that electronic signatures of the parties are intended to authenticate this writing and to have the same force and effect as manual signatures. **(C)**

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the day and year first above written.

ATTEST:

_____

UGI UTILITIES, INC. – GAS DIVISION

BY:_____
(Signature)

_____
(Print Name)

_____
(Title)

ATTEST:

_____

CHOICE SUPPLIER

BY:_____
(Signature)

_____
(Print Name)

_____
(Title)

(C) Indicates Change

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BOOK XI

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT F

PROPOSED SUPPLEMENT NO. 63 TO
UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
CLEAN AND REDLINED VERSIONS

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

CLEAN VERSION

PROPOSED SUPPLEMENT NO. 63

TO

UGI UTILITIES, INC. – GAS DIVISION

PA. P.U.C. NOS. 7 & 7S

UGI UTILITIES, INC. – GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Service and Choice Aggregation Service

in the

Territory Described Herein

Issued: January 28, 2026

Effective for service rendered on and after March 29, 2026.

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes changes, increases and decreases to existing rates (see Page 2-2(a)).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Cover Page
- Updated to reflect Supplement Number, Notice language, Issue and Effective dates.

Rule 8, Billing and Payment, Pages 42 & 45.
- Clarifying language added to section 8.4 as related to the timing of the periodic Budget Billing reviews.
- Formatting change to section 8.12, Payment Refunds, for consistency.
- Section 8.14 – Acceptable Forms of Payment has been added.

Rule 10, Rider A, State Tax Adjustment Surcharge, Page 48.
- The State Tax Adjustment Surcharge rate reset to 0.00%.

Rule 12, Rider C, Weather Normalization Adjustment, Page 53.
- The Weather Normalization Adjustment applicability has been updated to continue as a pilot from ending on October 31, 2027, to October 31, 2032.
- In Calculation of Adjustment Amount subsection (d), the Weather Normalization Adjustment has been changed from NHDD based upon the Delivery Region's 15-year average to 10-year average for the given day. Additionally, NHDD has been changed from being updated every 5 years to every rate case.

Rule 13, Rider D, Merchant Function Charge, Page 55.
- The rate has decreased for Residential PGC Customers to 2.37% and for Non-Residential PGC Customers to 0.47%.

Rule 15, Price to Compare, Page 57.
- The Price to Compare has changed as a result of the change to the Merchant Function Charge.

Rule 16, Rider F, Universal Service Program, Pages 58 & 59.
- The Universal Service Program applicability has added language for Rate XD customers on a negotiated basis and describes the applicability of the Rider and rate to Rate XD customers.
- The USP rate has added language to specify the rate for Rate R and Rate RT customers.
- The specific number of 25,404 has been removed and the applicability date has been updated from September 30, 2025 to September 30, 2026.

Rule 19, Rider I, Distribution System Improvement Charge, Page 63.
- The rate reset to 0.00%.

Rule 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, Pages 73 – 81.
- References to outdated Effective Date removed from heading.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Rate R – General Service – Residential, Page 85.
- The Customer Charge and Distribution Charge have been increased.

Rate RT – General Service – Residential Transportation, Page 86.
- The Customer Charge and Distribution Charge have been increased.

Rate GL – General Service – Gas Light Service, Page 88.
- The Distribution Charge has been increased.

Rate N – General Service – Non-Residential, Page 89.
- The Customer Charge and the Distribution Charge have been increased.

Rate NT – General Service – Non-Residential Transportation, Page 90.
- The Customer Charge and the Distribution Charge have been increased.

Rate DS – Delivery Service, Page 94.
- The Customer Charge and Maximum Distribution Charge have been increased.

Rate MBS – Monthly Balancing Service, Page 98(a).
- The Rate MBS charged to Rates DS/IS, LFD, and XD has been recalculated and updated.

Rate LFD – Large Firm Delivery Service, Pages 100-101.
- The Maximum Distribution Charge has been increased.
- The Annual Minimum Bill has clarifying language added.

Rate XD – Extended Large Firm Delivery Service, Page 103.
- The Maximum Average Delivery Charge has been increased.
- The Surcharges and Riders section has been updated to clarify that the Company may charge Rate XD customers Riders F and I based on the terms of individually negotiated contracts.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Choice Supplier Tariff

Cover Page
- Updated for Supplement Number and Issue and Effective dates.

Rule 4, Choice Supplier Obligations, Page 115.
- Subsection 4.12 – The residential and commercial Purchase of Receivable rates have been updated as a result of the change to the Merchant Function Charge.

RULES AND REGULATIONS

8. BILLING AND PAYMENT

8.1 Billing Month. Bills are rendered monthly. The Company normally reads meters monthly. However, at its option, the Company may read meters once every two months. In instances where meters are read every two months, the first month's bill will be based on an estimate of the consumption for the first month of the bi-monthly period. Bills are due when rendered and shall be considered as received by the Customer when left at, or mailed to, the address where service is rendered, or such other address as designated by the Customer. A billing month is the period upon which a Customer's monthly charges and consumption are computed and for which a bill is rendered. For Residential Customers, the billing month is a period of not less than 26 or greater than 35 days. An initial bill for a new Residential Customer may be less than 26 days or greater than 35 days; provided however, if an initial bill exceeds 60 days the Residential Customer shall be given the opportunity to amortize the amount over a period equal to the period covered by the initial bill without penalty. A final bill due to the discontinuance may be less than 26 days or greater than 35 days but may never exceed 42 days. In cases involving termination, a final bill may be less than 26 days. In addition, bills for less than 26 days or more than 35 days shall be permitted if they result from rebilling initiated by the Company or Customer dispute to correct a billing problem. Bills for less than 26 days or more than 35 days shall be permitted if they result from a meter reading route change initiated by the Company.

8.2 Estimated Consumption. When the Company is unable to obtain an actual meter reading because of inability to gain access to the meter, or because of extreme weather conditions, emergencies, equipment failures, work stoppages or any other circumstances, the Company will render appropriately marked estimated bills.

8.3 Application of a Rate Schedule. The Company will compute bills under the rate schedule selected by and for which the customer qualifies. In the event the customer does not select a Rate Schedule, the Company may discontinue service or place the Customer on a rate schedule for which the Customer qualifies.

8.4 Budget Billing. Residential Heating Customers may elect an optional billing method which averages the estimated Company regulated service costs over a revolving twelve (12) month Budget Billing plan. Company will review the Budget Billing amount on a quarterly basis and adjust the Budget Billing amount upward or downward based on actual charges to date and projected charges to the end of the twelve (12) month Budget Billing plan. The twelfth bill will include a true-up adjustment for the difference between payments made and actual charges for gas service for the prior eleven (11) months, inclusive. At the conclusion of the budget billing year, any resulting reconciliation amount exceeding $100 may be amortized over a twelve (12) month period upon Residential Heating Customer request. **(C)**

The optional twelve (l2) month Budget Billing plan, as described above, is available to Commercial and Industrial Heating Customers provided that at least seventy-five (75) percent of the Customer's total gas consumption is for space heating. If a Customer has an unpaid balance equal to the amount of two (2) Budget Bill Plan bills, billing under this plan may be terminated by the Company.

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued

separately listing charges from each company. The Company and UGI-ED shall, for such combined accounts, and subject to applicable statutory and regulatory requirements, establish a reasonable hierarchy of categories for the posting of partial payments to such joint accounts, and within each such category payments shall first be posted, as applicable, to UGI-ED or Electric Generation Supplier charges before being posted to UGI Gas Division or Natural Gas Suppler charges.

8.12 Payment Refunds. Refunds due customers greater than two dollars ($2) shall be mailed to the Customer. Refunds less than two dollars ($2) may be picked up at the office within sixty (60) days. After sixty (60) days, the refund shall be applied to Operation Share. **(C)**

8.13 Unless otherwise stated in this Section 8, Billing and Payment, all billing and payment provisions of this section apply to Customers served under all Company rate schedules, including Rate Schedules RT and NT where a Customer's Choice Supplier also participates in the Company's Purchase of Receivables ("POR") program.

8.14 Acceptable Forms of Payment. The Company accepts only the following forms of payment: a certified, cashier's, teller's or bank check; a personal check issued from an accredited financial institution; a money order from an official issuer; automatic bank drafting (AutoPay); wire transfer; Automated Clearing House (ACH); in cash at a third-party pay site; electronic by bank account, credit or debit card, or digital wallet through the Company's authenticated Online Account Center or Company website; electronic payment by phone through the Company's automated phone system or call center agent; electronic through a financial institution's banking system. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

10. RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.00% **(D)**

This Rider applies to Rates R, RT, GL, N, NT, DS, and LFD.

(D) Indicates Decrease

RULES AND REGULATIONS

12. Rider C

WEATHER NORMALIZATION ADJUSTMENT

Applicability and Purpose:

A Weather Normalization Adjustment ("WNA") shall be applied to bills of Residential and Non-Residential customers under Rate Schedules R, RT, N and NT, for any bills rendered during the heating season, which effective November 1, 2025 will include the months of October through April. Beginning with bills rendered on and after November 1, 2025, WNA will no longer be applied to confirmed low income residential customers who participate in the UGI Gas CAP program for CAP customers on a percent of income bill. CAP customers on average bill will continue to be billed based on an appropriate 12 month historic basis. The WNA commenced with bills rendered on and after November 1, 2022 and shall continue as a pilot which will end on October 31, 2032, unless affirmatively extended or otherwise permitted by Commission Order. **(C)**

WNA is a distribution charge adjustment and is considered a basic service charge.

Calculated WNA amounts shall be subject to Rider A – State Tax Adjustment Surcharge and Rider I – Distribution System Improvement Charge. No additional riders or surcharges will be applied to the calculated WNA.

Calculation of Adjustment Amount:

The WNA will be applied to October through May billing cycles and shall be calculated on a customer account specific basis in accordance with the formula below:

WNBC = BLMC + [((NHDD +/- (NHDD * 3%)) / AHDD) x (AMC-BLMC)]
WNAC = WNBC – AMC
WNA = WNAC x Distribution Charge

(a) Weather Normalized Billing Ccfs("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of the Normal Heating Degree Days ("NHDD", adjusted for a 3% deadband as further discussed in subparts (i) and (j) below), divided by the Actual Heating Degree Days ("AHDD") and the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.

(b) BLMC shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a thirty-six-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent thirty-six months of bill history. If less than twelve months of bill history is available for the premise, an average base load for the related customer class will be applied.

(c) AMC shall be measured for each customer and billing cycle and will be inclusive of any heating value corrections.

(d) NHDD shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's 10-year average for the given day. NHDD shall be updated every rate case using the methodology established in the Company's general rate case proceeding at R-2025-3059523. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

13. RIDER D

MERCHANT FUNCTION CHARGE

Applicability and Purpose

This Rider shall be applied to rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. The Rider is equal to the fixed percentage, established by the PUC in Company's last general base rate proceeding, of purchased gas costs which are expected to be uncollectible, and shall not be reconciled to reflect actual results. Rider D is intended to make Company's Price to Compare more comparable to the gas supply service prices offered of other Natural Gas Suppliers that presumably reflect anticipated uncollectible expenses.

Rider D Charge

Rider D charges shall be equal to 2.37% for Residential PGC Customers and 0.47% **(D)** for Non-Residential PGC Customers of Rider B (Purchased Gas Costs).

The collection of the Rider D charges will be summarized by Rate Schedule sub-accounts in the Gas Operating Revenue FERC Account No. 480000 for Rate R and 481000 for Rates N. The associated costs are recorded in FERC Account Nos. 904001 and 904002.

(D) Indicates Decrease

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	**Rate N (MCF)**	
Annual C-Factor	$ 0.62323	$ 6.2323	
Annual E-Factor	$ 0.05163	$ 0.5163	
Gas Procurement Charge	$ 0.00660	$ 0.0660	
Merchant Function Charge	$ 0.01599	$ 0.0317	**(D)**
Total Price to Compare	$ 0.69745	$ 6.8463	**(D)**

(D) Indicates Decrease

RULES AND REGULATIONS

16. RIDER F

UNIVERSAL SERVICE PROGRAM

APPLICABILITY AND PURPOSE

This Rider shall be applicable to all residential customers except customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs. This rider may also apply to customers receiving service under Rate XD on a negotiated rate basis. **(C)**

RATE

In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each MCF of sales volumes or distribution volumes distributed by the Company to customers receiving service under Rate Schedules R and RT. The USP rate for customers receiving service under Rate XD, if applicable, may differ from the USP rate stated below and may be applied on a volumetric, fixed charge, percentage or other basis. **(C)**

The USP rate for Rate R and Rate RT: $0.6363/Mcf **(C)**

The USP rate for Rate XD: as negotiated, but no greater than the above rate. **(C)**

CALCULATION OF RATE

The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low-income program that is implemented during the period that the Rider is in effect.

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include
1) the projected CAP credit
2) projected CAP customer application and administrative costs; and
3) projected CAP pre-program arrearage forgiveness.

CAP Credit shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes.

(C) Indicates Change

RULES AND REGULATIONS

16. RIDER F - Continued

UNIVERSAL SERVICE PROGRAM

QUARTERLY ADJUSTMENT

Any time that the Company makes a change in base rates or PGC rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION

On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP and actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 9.2% adjustment for amounts granted to participants in excess of the number of CAP enrollees as of September 30, 2026. The 9.2% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following: (C)

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits in excess of the number of CAP enrollees as of September 30, 2026 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0920 in order to determine the amount of the CAP Credits which will not be recovered through Rider USP. (C)

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness in excess of the number of CAP enrollees as of September 30, 2026 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0920 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP. (C)

(C) Indicates Change

RULES AND REGULATIONS

19. Rider I

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply. **(D)**

19.A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

19.A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Piping, Couplings, Valves, Excess Flow Valves, Risers - Distribution & Transmission. (Accts. 374, 376, 365, 367)
- Measuring & Regulator Stations – Distribution & Transmission (Accts. 375, 378, 379, 366, 369, 370)
- Gas Service Lines and Insulated and Non-Insulated Fittings (Accts. 378, 380)
- Meters, Meter Bars, Meter Installations (Accts. 381, 382)
- House Regulators & Installations (Accts. 383, 384)
- Industrial & Farm Tap Measuring & Regulator Station Equipment (Accts. 385, 386)
- Miscellaneous Equipment and Material– Distribution & Transmission (Accts. 387, 371)
- Equipment – Electronic Systems & Software (Accts. 391)
- Vehicles, Power Equipment, Tools, Shop & Garage Equipment (Accts. 392, 394, 396)
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities.
- Gathering lines (Accts. 332)
- Storage lines (Accts. 353)
- Other related capitalized costs.

19.A.3 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

(D) Indicates Decrease

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS **(C)**

22.1 Application of Rates

(a) Applicable Rates: DS, LFD, XD and IS.

(b) Notification of Delivery; Nomination Procedures. Customer shall notify the Company of any and all gas deliveries to the Company's system, including, but not limited to, the provision of nomination, revised nomination and scheduling information, in accordance with the Company's *Nomination Procedure*, as may be amended from time to time, and made available on the Company's Gas Management Website ("Nomination Procedure"). The quantity of gas received on behalf of the Customer shall be determined by allocation or other method by the Company if required in its sole discretion. It is the Customer's responsibility to arrange that any necessary billing information be provided to the Company and/or delivery gas source.

(c) Nominating Agents. A Customer shall notify the Company of its designated nominating agent ("Agent") for purposes of nominating the volumes of natural gas to be delivered to the Company's system on the Customer's behalf in accordance with the Nomination Procedures. Customer shall notify Company, on a form designated by the Company in the Nomination Procedures, of the responsibilities of the Agent, and shall provide Company with the Agent's valid e-mail address and valid 24-hour contact information. Customer shall remain liable for all charges and penalties notwithstanding Customer's designation and use of an Agent in accordance with the provisions herein.

(d) Penalties for Customer's Default. Customers failing to provide nomination, billing, scheduling, agent, supplier and/or other required information to the Company or pipeline(s)in accordance with the provisions of the Tariff, or otherwise failing to comply with the Company's *Nomination Procedure*, shall be subject to applicable imbalance charges and, in addition, be charged an Administrative Scheduling Fee in an amount no greater than $1,000 per day for every day such required information is delayed. If a Customer default of these provisions occurs and is occurring for a period of 90 days, the Company may impose retail or standby rates on the Customer's account beginning the first day after such 90-day period through and until such time as the Company deems the Customer default to have been resolved.

(e) Sequencing for Billing. Unless otherwise agreed by the Company and the Customer, customer-owned gas delivered under the transportation rate schedules shall be sequenced for billing as the first gas through the meter, and gas purchased under the Retail and Standby Rider shall be sequenced for billing purposes as the last gas through the meter. Gas billed under firm rate schedules shall be billed prior to gas billed under interruptible rate schedules. In lieu of otherwise specified tariff provisions, where the Company and Customer agree, Company shall use pipeline metering facilities for measuring and billing total deliveries to the Customer's facility.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

(f) Payment of Charges, Penalties. The Customer shall pay the Company for any and all additional charges incurred on the Customer's behalf or resulting from the Customer's actions or inactions which the Company can demonstrate arise out of the provision of transportation service including, but not limited to, pipeline transportation and service charges. Any such charge, penalty or obligation imposed by a pipeline transporter or supplier as result of balancing of gas delivered to the Customer shall be paid by the Customer in addition to otherwise applicable charges.

(g) The Billing Pool Agent is required to notify Company at least ten days prior to dropping a Customer from a Billing Pool. If adequate advance notice is not provided, the Company reserves the right to not drop the Customer from the Billing Pool.

(h) Billing Pools. One or more transportation Customers may join together in pooled transactions for the purchase and delivery of gas. The Company may allocate among all such customers the volumes of gas or imbalances for purposes of determining responsibility for charges, rates, penalties or other obligations imposed by the Company, or in connection with operation of the pool. A Supplier to a Billing Pool must notify the Company prior to initiating gas deliveries. A Customer is required to submit in writing a request for entry into a Billing Pool.

(1) Each Billing Pool shall appoint an Agent who will coordinate nomination, billing, reconciliation, allocation and any other necessary communication between the Billing Pool and the Company.

(2) All members of a Billing Pool shall be of like balancing service election. The Company may restrict formation or operation of any Billing Pool in order to meet like balancing service election or pipeline imposed eligibility requirements.

(3) Automated Meter Reading. The Company has the right as a condition of being a pool member, to install, at the Customer’s expense, automated meter reading (“AMR”) equipment for the purposes of daily collection or monitoring, and billing Customer volumes at each related service meter. Where AMR equipment is installed, the Customer shall maintain, at its expense, unless otherwise directed by the Company, a dedicated phone connection and electric service to the AMR equipment which will allow the Company unlimited remote access to the AMR device at all times. Failure to maintain a required phone and/or electric service may result in Customer being removed from a Billing Pool and being placed on a rate schedule not requiring daily measurement capability.

(4) Service under Rate NNS is required by, and shall be individually billed to, any and all members of a Billing Pool except when all pool members are monitored on a daily basis through the use of Company owned AMR equipment at all meter locations. Additionally, service under Rate MBS is required by, and shall be individually billed to, any and all members of a Billing Pool when the billing month for each pool member does not end on the same calendar date; Billing Pools having all customers monitored and billed through the use of Company owned AMR equipment at all meter locations shall be exempt from this requirement.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

(i) Recognition of Supplies. Volumes transported on behalf of the Customer will be recognized in the Customer's current billing month based on nominated or scheduled volumes information and may be adjusted after notification is received from the pipeline supplier(s) of the volumes transported on behalf of the Customer. Volumes scheduled shall be determined on the basis of best available actual or confirmed pipeline and/or Company information at the time of billing.

(j) Unless otherwise negotiated under Rate XD, the Company shall retain for Company use gas, and lost and unaccounted for gas, 1.5% of the total volume of gas delivered into its system for the Customer’s account.

22.2 Balancing and No-Notice Service.

(a) Each Customer shall use best efforts to balance purchases, deliveries and receipts of gas at all times. Except as specified in 22.1(f), for the purposes of balancing excess deliveries and shortfalls and purchasing services under Rates NNS and MBS, Billing Pools may be treated as a single entity. Subject to the terms and conditions set forth below, the Company shall provide no-notice and monthly balancing services under Rate Schedules NNS and MBS. Service under Rate Schedules NNS and MBS is available only for inadvertent fluctuations, limited by the terms and conditions of each Rate Schedule, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. In the event the Customer fails to use best efforts to balance deliveries and receipts, or otherwise misuses no-notice or balancing services as determined by the Company in its sole discretion, Section 22.4 shall apply for the period of such default or misuse.

(b) Daily Balancing. The Company shall allow Customer's daily demand to inadvertently vary from daily scheduled deliveries by +/-4.5% without imposing Daily Balancing Charges, provided the total daily quantity taken does not exceed Customer's Daily Firm Requirement, MDQ or otherwise specified contract demand limit. Daily imbalances in excess of the +/-4.5% tolerance, unless otherwise provided by service elected under Rate NNS, shall be assessed a Maximum Daily Excess Balancing Charge in accordance with Section 22.4 under Critical Day and Non-Critical Day criteria unless otherwise specified in Customer's contract, in addition to the charges specified in Rates DS, LFD, XD and IS, on all such quantities.

(c) Imbalance Resolution. Customer's monthly imbalances will be calculated at the end of each billing period to determine if any overdelivery (excess) or underdelivery (shortfall) condition exists for volumes scheduled versus volumes metered. If the Customer is determined to be in an imbalance condition, and has not elected service under Rate MBS or has exceeded the 10% imbalance allowance provided under Rate MBS, then the Company shall sell and the Customer shall buy, subject to the 5 percent limitation under Rate MBS, any shortfall amount according to the following cash-out pricing:

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

Shortfall Percent	Cash-Out Price
Up to 5%	Shortfall Monthly Reference Price("SMRP")
Greater than 5%, but not greater than 15%	SMRP x 1.1
Greater than 15%, but not greater than 25%	SMRP x 1.3
Greater than 25%	SMRP x 1.5

Likewise, the Customer shall sell, and the Company shall buy any excess amount according to the following cash-out pricing:

Excess Percent	Cash-Out Price
Up to 5%	Excess Monthly Reference Price("EMRP")
Greater than 5%, but not greater than 15%	EMRP x 0.9
Greater than 15%, but not greater than 25%	EMRP x 0.7
Greater than 25%	EMRP x 0.5

The SMRP (Shortfall Monthly Reference Price) shall be the average of the DPP midpoint Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The EMRP (Excess Monthly Reference Price) shall be the average of the DPP midpoint Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

Customer Delivery Region shall be assigned to each Customer in accordance with Customer's delivery location within the Company's distribution system.

The SMRP and EMRP are applicable to the above tables only for inadvertent monthly imbalances. The HMRP (Highest Monthly Reference Price) or the LMRP (Lowest Monthly Reference Price) as defined below shall apply respectively to shortfall and excess conditions in those situations where intentional imbalances are involved.

The HMRP shall be calculated as the highest of the DPP absolute Reference Prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The LMRP shall be calculated as the lowest DPP absolute reference prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

(d) The Company may extend the balancing period for gas volumes and may increase volumes eligible for balancing in its discretion, but only if it determines that such action is consistent with its obligations to other customers.

(e) Supply Transfers. In order to facilitate Monthly balancing related to inadvertent imbalances in Company's sole discretion, the Company shall allow Supply Transfers among Customers and Billing Pools, Customers-to-Billing Pools and Billing Pools-to-Customers at a fee of $125 per transaction, provided however: (1) such transfer is requested prior to the end of the billing month for both the transferee and the transferor, (2) such transfer is physically possible given pipeline interconnection and delivery point limitations which require transfers to be between parties located on the same segment of the Company's distribution system, and system supplies, and reliability are not adversely affected.

(f) Competitive Volume Customers. In the case of Customers or applicants seeking service for facilities with a design volume capability allowing for direct connection to transmission or gathering lines for bypass of Company facilities, Company shall have the right to establish daily and monthly balancing tolerances at levels other than those specified in subsections (b) and (c) of this Section 22.2 to reflect specific operational limitations or to protect the interests of other Customers, as determined by the Company in its sole discretion. Additionally, the Company may establish special nomination rules, imbalance resolution rules and communication protocols that reflect the Customer's or applicant's commercial alternatives, and which are consistent with its obligations to other Customers.

22.3 Service Agreement and General.

(a) Limitation on Liability.

(1) The Company shall not be liable for curtailment of service under Rates DS, LFD, XD and IS, or loss of the Customer's gas as a result of any steps taken to comply with any law, regulation or order of any governmental agency with jurisdiction to regulate, allocate or control gas supplies or the rendition of service hereunder, and regardless of any defect in such law, regulation or order.

(2) Gas transported and delivered by the Company to the Customer hereunder shall be and remain the property of the Customer. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during and after receipt by the Company.

(3) The Company shall not be liable for any loss to the Customer arising from or out of service hereunder, including loss of gas in the possession of the Company or any other cause, except gross or willful negligence of the Company's own employees or agents. The Company reserves the right to commingle gas of the Customer with other supplies.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

(b) Warranty, indemnity and special provisions. The receipt of service constitutes Customer's agreement to the following representations and warranties, together with related provisions in the service agreement:

(1) clear and marketable title to the Customer's gas;
(2) delivery points, pressure, quality and other specifications acceptable to gas transmission pipeline(s) and the Company;
(3) eligibility of the Customer for service;
(4) existence of lawful authority for sale, transportation and delivery;
(5) agreement to pay all excise, sales, use, gross receipts, or other taxes (other than income taxes), all tariff charges and all penalties, charges, fees for transportation, balancing etc., associated with delivered gas, which may be levied upon or incurred by the Company at any time;
(6) agreement to indemnify and hold the Company harmless from breach of representations or warranties, and any liability associated with Customer's gas while on the Company's system.

Copy of Gas Purchase Agreements, Other Documents. When requested by the Company, the Customer shall provide the Company with a copy of Customer's gas purchase contract and any related transportation, marketing and brokerage contracts, or, in lieu of providing such contracts, certify pertinent information as required by the Company, and, in order to meet state or federal requirements, provide a sworn affidavit setting forth the Customer's cost of gas for the period requested by the Company. The Company shall endeavor to protect the confidentiality of information provided by the customer in accordance with this provision. The Company will provide such information to third parties only when required to do so by law, regulation or order and in such case, will attempt to maintain confidentiality to the extent possible.

22.4 Maximum Daily Excess Balancing Charge

The Daily Excess Balancing Charge that occurs on Critical Days shall be as follows:

The charge for exceeding daily balancing limits shall be ten times the highest price in the DPP for each delivery region as listed in the following table. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into Pennsylvania.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

Delivery Region	Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.
Central	The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco Zone 6 to Zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The Daily Excess Balancing Charge that occurs on Non-Critical Days shall be as follows:

Daily Imbalance Percent	Penalty
Up to 15%	DRP
Greater than 15%, but not greater than 30%	DRP x 2
Greater than 30%, but not greater than 45%	DRP x 3
Greater than 45%, but not greater than 60%	DRP x 4
Greater than 60%	DRP x 5
Intentional imbalances	DRP x 5

The DRP (Daily Reference Price) shall be equal to the difference in price between the highest DPP Reference Price and the lowest DPP Reference Price for the Customer's Delivery Region as listed below but shall not be lower than $0.25/Mcf.

Delivery Region	Highest Reference Price	Lowest Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.	Tennessee, zone 4- 300 leg
Central	Transco zone 6, non-N.Y.	Transco, Leidy line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS – Continued **(C)**

The Company shall not charge any Maximum Daily Excess Balancing Charges if the Customer's Excess Daily Imbalance is anticipated to benefit the distribution systems daily balancing position as determined by Company in its sole discretion.

22.5 Operational Flow Orders and Daily Flow Directives

The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Twenty-Five ($25) per Mcf or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater.

22.6 Cost of Assigned Capacity.

In addition to applicable interstate pipeline demand charges, the associated demand charges to customers, or their NGS, served under Rates DS, LFD, XD, and who utilize assigned PGC capacity and pay weighted average cost, will include 100% (DS) and 50% (LFD, XD) pro rata allocation of annual Peaking Supply service demand costs. The associated demand charges will be reduced by a pro rata share of the Economic Benefit of Peaking Supply (EBPS Credit). The EBPS Credit shall mean a pro rata share of (a) the value of Peaking Supply utilized in off system sales transactions and included in the PGC share of the Revenue Sharing Incentive Mechanism revenues, plus (b) the Commodity Price Differential, which shall be, as measured for the date of Peaking Supply delivery, the aggregate difference, if positive, between the DPP Reference Price applicable to the zone of delivery (i.e., Texas Eastern M3 for deliveries in the South and West Delivery Regions with the exception of deliveries from Mt. Bethel and Transco Z6 NNY for deliveries made in the North and Central Delivery Regions and deliveries from Mt. Bethel) and the actual price paid for actual Peaking Supply deliveries into the UGI distribution system. The EBPS Credit shall be applied in the calculation of associated demand charges in the second billing month after the credit has accrued (e.g., December accrued credits will be used to reduce the February associated demand charges) and shall not, on an annual basis, exceed the annual incremental demand charges for Peaking Services charged to Rate DS, LFD, and XD customers, or their NGS, as described above.

(C) Indicates Change

RATE R

GENERAL SERVICE – RESIDENTIAL

AVAILABILITY

This rate applies to all Residential Customers in the entire gas service territory of the Company and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $23.00 per customer **(I)**

Plus Distribution Charge: $0.68383/Ccf **(I)**

Plus SURCHARGES and RIDERS

Rider A – State Tax Adjustment Surcharge
Rider B – Section 1307 (f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment
Rider D – Merchant Function
Rider E – Gas Procurement Charge
Rider F – Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase

RATE RT

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies to all Residential Customers in the entire gas service territory who are served by a qualified Choice Supplier receiving service under Rate AG and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $23.00 per customer **(I)**

Plus Distribution Charge: $0.68383/Ccf **(I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C - Weather Normalization Adjustment
Rider F - Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase

RATE GL

GENERAL SERVICE - GAS LIGHT SERVICE

AVAILABILITY

This service is available for street, highway, driveway or other lighting or sign illumination, where measurement by meter of the gas consumed is not practicable or economical. As used herein, "light" means a single lamp or sign having one (1) gas-flow orifice and one (1) or more mantles, and of a type approved by the Company.

MONTHLY RATE TABLE

Distribution Charge: $0.68383/Ccf **(I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B – Section 1307(f) Purchased Gas Cost
Rider I – Distribution System Improvement Charge

Monthly usage is assumed to be 1.8 Mcf, however, for larger consumption input fixtures, the Company reserves the right to modify.

BILLS DUE

All bills for continuing service are due each month when rendered, and the final due date stated on the bill shall be no less than fifteen (15) days from the date of presentation. Upon discontinuance of service, bills are due and payable upon presentation.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

SPECIAL TERMS AND CONDITIONS

Gas will be supplied to lights furnished, erected and maintained by the customer only when equipped with regulators and such devices as the Company considers necessary for turning lights on and off for maintenance and safety purposes.

(I) Indicates Increase

RATE N

GENERAL SERVICE – NON-RESIDENTIAL

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Non-Residential Customers, using gas for any purpose including gas purchased by another public utility for resale. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate N service may not be applied to supplement or back up any transportation service.

MONTHLY RATE TABLE

Customer Charge: $39.00 per customer **(I)**

Plus Distribution Charge: $5.0297/Mcf **(I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B - Section 1307(f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment
Rider D – Merchant Function Rider
Rider E – Gas Procurement Charge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE
The Customer Charge as set forth above.

MINIMUM BILL PROVISION
If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT
In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase

RATE NT

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Customers who are served by a Choice Supplier receiving service under Rate AG, except residential Customers, using gas for any purpose. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate NT service may not be applied to supplement or back up any transportation or retail service.

MONTHLY RATE TABLE

Customer Charge: $39.00 per customer **(I)**

Plus Distribution Charge: $5.0297/Mcf **(I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Weather Normalization Adjustment
Rider G – Energy Efficiency and Conservation
Rider H - Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

The Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase

RATE DS

DELIVERY SERVICE

AVAILABILITY

This service applies in the entire territory served by the Company. Firm Delivery Service shall be provided for all volumes supplied by the Customer for which the Company has available on system delivery capacity, subject to Section 21 - Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

The Customer must execute a Service Agreement for not less than (1) one year. The contract shall continue in force for consecutive (1) year periods unless cancelled by the Customer upon ninety (90) days written notice to Company prior to the expiration of a contract term.

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable delivery service balancing provisions or in accordance with optionally elected and approved balancing or standby services.

Service under Rate DS is subject to the terms set forth under Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Capacity Charge if applicable, and the Distribution Charge as described below. The following are maximum rates.

Customer Charge: $353.00 per month **(I)**

Plus Capacity Charge: The Company’s unitized weighted average cost of firm transportation capacity per elected MDQ.

Plus Maximum Distribution Charge: $3.3652/Mcf **(I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

(I) Indicates Increase

RATE MBS - Continued

MONTHLY BALANCING SERVICE

MONTHLY RATE TABLE

Monthly Transportation Volume

Rate DS/IS	$0.0198/Mcf x Monthly Billed Volumes	**(I)**
Rate LFD	$0.0113/Mcf x Monthly Billed Volumes	**(I)**
Rate XD	$0.0116/Mcf x Monthly Billed Volumes	**(I)**

The Company will update the average monthly imbalance utilized in the development of Rate MBS charges annually with the actual average monthly imbalance for the 12-month period ending September to determine the new Rate MBS charges effective December 1 each year. The Company shall include the new Rate MBS charges as part of its annual PGC compliance filing.

(I) Indicates Increase

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Demand Charge, the Capacity Charge (if applicable), the Distribution Charge and any Excess Take Charge as described below. The following are maximum rates.

Customer Charge: $670.00

Plus
Maximum Demand Charge: $7.6956/Mcf of Customer's elected DFR.

Plus
Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected DFR. Applicable only when the customer elects UGI capacity.

Plus
Maximum Distribution Charge (all volumes): $1.4173/Mcf **(I)**

Plus
SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I - Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

RETAINAGE RATE

Company Use and Unaccounted for Gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j).

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

EXCESS TAKE CHARGE

Except as provided in the Company's *Nomination Procedure*, for authorized usage on any day in excess of the Daily Firm Requirement there will be a charge of $6.00 per MCF in addition to the charges specified in the rate table.

(I) Indicates Increase

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge, Demand Charge, Capacity Charge (if applicable), and Charge for Other Transportation.

Annual: Unless a higher amount is agreed upon by the Company and Customer, the Minimum Annual Bill shall be based on the Customer maintaining a 0.50 annual load factor and shall be due and payable with the bill for the 12th month in the contract year. The Customer's actual load factor shall be determined by dividing the total volume of gas taken during the contract year (including volumes taken under the Retail and Standby Rider, and the Cash-Out provisions of Section 22.2) by the sum of the Daily Firm Requirements for the contract year. If the actual load factor is less than 0.50, then, in addition to payment for actual usage, the Customer shall pay a Minimum Annual Bill charge equal to the product of: (1) the difference between 0.50 and the actual load factor, (2) the sum of the Customer's Daily Firm Requirements for the contract year, and (3) the average delivery charge paid by the Customer over the previous 12-month period, as calculated by the Company. If the Customer's actual load factor is greater than or equal to 0.50, no Minimum Annual Bill charge will be required. **(C)**

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company. Such charges related to the use of Customer elected and Company provided transportation capacity shall be reflected directly on the Customer’s bill for service rendered on and after April 1, 2024, pursuant to Commission order at Docket R-2023-3040290, with such charges labeled on the bill as Capacity Charge.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Fifty Dollars($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Section 22.4 is primarily intended to establish applicable daily imbalance penalty charges but shall also provide for the pricing applicable to any Unauthorized Overrun volumes, which shall be subject to the same pricing as an Intentional imbalance. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun.

SERVICE UNDER OTHER RATES

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purposes of determining Excess Take Charge and Unauthorized Overrun gas.

(C) Indicates Change

RATE XD -Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be negotiable and shall be the sum of the Customer Charge, Distribution Charge, Demand Charge if applicable, the Capacity Charge (if applicable), and the Minimum Annual Bill as described below.

The following are maximum rates.

Customer Charge: Charge as determined by negotiation.

Plus
Maximum Demand Charge: Charge as determined by negotiation.

Plus
Capacity Charge: On or after October 28, 2025 when current Rate XD contracts expire, Capacity available for Customer use, and related Capacity Charge, shall be as specified within Customer's service contract, provided Company has available capacity and Company and Customer agree to related terms. For Customers electing Company capacity, such Capacity Charge shall be charged at the Company's unitized weighted average cost of firm transportation capacity per elected DFR. However, for Customers specifically receiving assignment of Columbia Pipeline capacity via agreement with the Company and through capacity release, such Customers, or their NGS, shall pay capacity charges direct to Columbia in accordance with such release. For Customers not receiving any Company capacity, no Capacity Charge will apply.

Plus
Maximum Average Delivery Charge: $1.4173/Mcf **(I)**

Plus **(C)**
SURCHARGES and RIDERS where negotiated

(C)
Rider F – Universal Service Program
Rider I – Distribution System Improvement Charge

RETAINAGE RATE

Unless otherwise agreed between the Customer and the Company, Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j)

MINIMUM BILL

Minimum Bill Volumes and terms shall be defined in the Service Agreement and determined by negotiation.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the Customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

(I) Indicates Increase (C) Indicates Change

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Aggregation Service

Issued: January 28, 2026

Effective for service rendered on and after March 29, 2026

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This supplement makes increases and changes to existing rates (see page 2(b)).

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.12 If a Choice Supplier elects to participate in the Company's POR Program, the Choice Supplier must enter into a POR Agreement for the rate classes that it serves that will be included in the POR. The elected Rate Classes shall be one of the following: (1) RT only, (2) NT only, or (3) RT and NT. All receivables associated with basic natural gas supply services in the specific rate class, subject to the rate class elections made above, must be sold by the participating Supplier to the Utility. For the purposes of this provision, the phrase "basic natural gas supply services" shall include charges directly related to the physical delivery of natural gas to a retail customer but shall not include charges for "carbon-neutral" products, appliance maintenance service, energy efficiency services, termination or cancellation fees, security deposits or other products or services not directly related to the physical delivery of natural gas to a retail customer. Customer accounts that are billed for non-basic natural gas supply services will not be eligible for UGI's POR program. All of the NGS' customer accounts within the elected Rate Classes (subject to the volumetric limits contained in section 5.4) must be POR eligible accounts, with the exception of customers that purchase carbon-neutral products. NGSs may choose to use UGI consolidated billing for Non-POR eligible customers who are purchasing bundled "carbon-neutral" product offerings. The termination and reconnection provisions of Chapters 14 and 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing. UGI shall support rate-ready billing, and all NGS rates must conform to supported rate designs. For Purchased Customer Accounts, Company shall pay Choice Supplier an amount equal to 97.49% for residential amounts billed (inclusive of associated sales taxes) and 99.39% of non-residential amounts billed (also inclusive of taxes). Customer participation for NT shall be subject to Volumetric Eligibility pursuant to Section 5.4. **(C)** **(C)**

4.13 All existing customers of Choice Suppliers who elect to participate in the Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier and Company that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

All new customers enrolling with Choice Suppliers who are participating in Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier prior to enrollment, and by Company upon enrollment, that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

(C) Indicates Change

REDLINED VERSION

PROPOSED SUPPLEMENT NO. 63

TO

UGI UTILITIES, INC. – GAS DIVISION

PA. P.U.C. NOS. 7 & 7S

UGI UTILITIES, INC. – GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Service and Choice Aggregation Service

in the

Territory Described Herein

Issued: ~~November 26, 2025~~January 28, 2026

Effective for service rendered on and after ~~December 1, 2025~~March 29, 2026. ~~Issued in accordance with the Commission's Ordered entered September 25, 2025 at Docket No. R-2025-3054938.~~

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes changes, increases and decreases to existing rates (see Page 2-2(a)).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Cover Page
- Updated to reflect Supplement Number, Notice language, Issue and Effective dates.

Rule 8, Billing and Payment, Pages 42 & 45.
- Clarifying language added to section 8.4 as related to the timing of the periodic Budget Billing reviews.
- Formatting change to section 8.12, Payment Refunds, for consistency.
- Section 8.14 – Acceptable Forms of Payment has been added.

Rule 10, Rider A, State Tax Adjustment Surcharge, Page 48.
- The State Tax Adjustment Surcharge rate reset to 0.00%.

Rule 12, Rider C, Weather Normalization Adjustment, Page 53.
- The Weather Normalization Adjustment applicability has been updated to continue as a pilot from ending on October 31, 2027, to October 31, 2032.
- In Calculation of Adjustment Amount subsection (d), the Weather Normalization Adjustment has been changed from NHDD based upon the Delivery Region's 15-year average to 10-year average for the given day. Additionally, NHDD has been changed from being updated every 5 years to every rate case.

Rule 13, Rider D, Merchant Function Charge, Page 55.
- The rate has decreased for Residential PGC Customers to 2.37% and for Non-Residential PGC Customers to 0.47%.

Rule 15, Price to Compare, Page 57.
- The Price to Compare has changed as a result of the change to the Merchant Function Charge.

Rule 16, Rider F, Universal Service Program, Pages 58 & 59.
- ~~The Universal Service Program applicability has added language to~~ for Rate XD customers on a negotiated basis and describes the applicability of the Rider and rate to Rate XD customers.
- ~~The Universal Service Program rate has added language stating the USP rate for Rate XD customers may differ from the Rate R and Rate RT USP rate.~~
- The USP rate has added language to specify the rate for Rate R and Rate RT customers.
- ~~Language for the USP rate for Rate XD has been added.~~
- The specific number of 25,404 has been removed and the applicability date has been updated from September 30, 2025 to September 30, 2026.

Rule 19, Rider I, Distribution System Improvement Charge, Page 63.
- The rate reset to 0.00%.

Rule 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, Pages 73 – 81.
- References to outdated Effective Date removed from heading.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – Continued
(Page Numbers Refer to Official Tariff)

Rate R – General Service – Residential, Page 85.
- The Customer Charge and Distribution Charge have been increased.

Rate RT – General Service – Residential Transportation, Page 86.
- The Customer Charge and Distribution Charge have been increased.

Rate GL – General Service – Gas Light Service, Page 88.
- The Distribution Charge has been increased.

Rate N – General Service – Non-Residential, Page 89.
- The Customer Charge and the Distribution Charge have been increased.

Rate NT – General Service – Non-Residential Transportation, Page 90.
- The Customer Charge and the Distribution Charge have been increased.

Rate DS – Delivery Service, Page 94.
- The Customer Charge and Maximum Distribution Charge have been increased.

Rate MBS – Monthly Balancing Service, Page 98(a).
- The Rate MBS charged to Rates DS/IS, LFD, and XD has been recalculated and updated.

Rate LFD – Large Firm Delivery Service, Pages 100-101.
- The Maximum Distribution Charge has been increased.
- The Annual Minimum Bill has clarifying language added.

Rate XD – Extended Large Firm Delivery Service, Page 103.
- The Maximum Average Delivery Charge has been increased.
- The Surcharges and Riders section has been updated to clarify that the Company may charge Rate XD customers ~~"where negotiated" language added.~~
- ~~Under Surcharges and Riders,~~ Riders F and ~~F~~I based on the terms of individually negotiated contracts ~~– Universal Service Program, has been added~~.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Choice Supplier Tariff

Cover Page
- Updated for Supplement Number and Issue and Effective dates.

Rule 4, Choice Supplier Obligations, Page 115.
- Subsection 4.12 – The residential and commercial Purchase of Receivable rates have been updated as a result of the change to the Merchant Function Charge.

RULES AND REGULATIONS

8. BILLING AND PAYMENT

8.1 Billing Month. Bills are rendered monthly. The Company normally reads meters monthly. However, at its option, the Company may read meters once every two months. In instances where meters are read every two months, the first month's bill will be based on an estimate of the consumption for the first month of the bi-monthly period. Bills are due when rendered and shall be considered as received by the Customer when left at, or mailed to, the address where service is rendered, or such other address as designated by the Customer. A billing month is the period upon which a Customer's monthly charges and consumption are computed and for which a bill is rendered. For Residential Customers, the billing month is a period of not less than 26 or greater than 35 days. An initial bill for a new Residential Customer may be less than 26 days or greater than 35 days; provided however, if an initial bill exceeds 60 days the Residential Customer shall be given the opportunity to amortize the amount over a period equal to the period covered by the initial bill without penalty. A final bill due to the discontinuance may be less than 26 days or greater than 35 days but may never exceed 42 days. In cases involving termination, a final bill may be less than 26 days. In addition, bills for less than 26 days or more than 35 days shall be permitted if they result from rebilling initiated by the Company or Customer dispute to correct a billing problem. Bills for less than 26 days or more than 35 days shall be permitted if they result from a meter reading route change initiated by the Company.

8.2 Estimated Consumption. When the Company is unable to obtain an actual meter reading because of inability to gain access to the meter, or because of extreme weather conditions, emergencies, equipment failures, work stoppages or any other circumstances, the Company will render appropriately marked estimated bills.

8.3 Application of a Rate Schedule. The Company will compute bills under the rate schedule selected by and for which the customer qualifies. In the event the customer does not select a Rate Schedule, the Company may discontinue service or place the Customer on a rate schedule for which the Customer qualifies.

8.4 Budget Billing. Residential Heating Customers may elect an optional billing ~~procedure~~ method which averages the estimated Company regulated service costs over a revolving twelve (12) month Budget Billing plan. ~~These Customers will be billed for the use of gas during the next eleven (11) months beginning with whatever month that they select.~~ –Company will review the Budget Billing amount on a quarterly basis ~~upon the completion of the third (3rd), sixth (6th), and ninth (9th) billing months with budget asked to pay amounts adjusting the fourth (4th), seventh (7th) and tenth (10th) billing months annually~~ and adjust~~ing~~ the Budget Billing amount upward or downward ~~the Budget Billing amount~~ based on actual charges to date and projected charges to the end of the twelve (12) month Budget Billing plan. The twelfth bill will ~~be for usage for the month, with~~include a true-up~~n~~ adjustment for the difference between payments made and actual charges for gas service for the prior eleven (11) months, inclusive. At the conclusion of the budget billing year, any resulting reconciliation amount exceeding $100 may be amortized over a twelve (12) month period upon Residential Heating Customer request. (C)

The optional twelve (12) month Budget Billing plan, as described above, is available to Commercial and Industrial Heating Customers provided that at least seventy-five (75) percent of the Customer's total gas consumption is for space heating. If a Customer has an unpaid balance equal to the amount of two (2) Budget Bill Plan bills, billing under this plan may be terminated by the Company.

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued

separately listing charges from each company. The Company and UGI-ED shall, for such combined accounts, and subject to applicable statutory and regulatory requirements, establish a reasonable hierarchy of categories for the posting of partial payments to such joint accounts, and within each such category payments shall first be posted, as applicable, to UGI-ED or Electric Generation Supplier charges before being posted to UGI Gas Division or Natural Gas Suppler charges.

8.12 Payment Refunds. Refunds due customers greater than two dollars ($2) shall be mailed to the Customer. Refunds less than two dollars ($2) may be picked up at the office within sixty (60) days. After sixty (60) days, the refund shall be applied to Operation Share. **(C)**

8.13 Unless otherwise stated in this Section 8, Billing and Payment, all billing and payment provisions of this section apply to Customers served under all Company rate schedules, including Rate Schedules RT and NT where a Customer's Choice Supplier also participates in the Company's Purchase of Receivables ("POR") program.

8.14 Acceptable Forms of Payment. The Company accepts only the following forms of payment: a certified, cashier's, teller's or bank check; a personal check issued from an accredited financial institution; a money order from an official issuer; automatic bank drafting (AutoPay); ~~by~~ wire transfer; ~~by~~ Automated Clearing House (ACH); in cash at a third-party pay site; electronic by bank account, credit or debit card, or digital wallet through the Company's authenticated Online Account Center or Company website; electronic payment by phone through the Company's automated phone system or call center agent; electronic through a financial institution's banking system. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

10. RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.~~01~~00% **(~~I~~D)**

This Rider applies to Rates R, RT, GL, N, NT, DS, and LFD.

(~~I~~D) Indicates ~~Increase~~ Decrease

RULES AND REGULATIONS

12. Rider C

WEATHER NORMALIZATION ADJUSTMENT

Applicability and Purpose:

A Weather Normalization Adjustment ("WNA") shall be applied to bills of Residential and Non-Residential customers under Rate Schedules R, RT, N and NT, for any bills rendered during the heating season, which effective November 1, 2025 will include the months of October through April. Beginning with bills rendered on and after November 1, 2025, WNA will no longer be applied to confirmed low income residential customers who participate in the UGI Gas CAP program for CAP customers on a percent of income bill. CAP customers on average bill will continue to be billed based on an appropriate 12 month historic basis. The WNA commenced with bills rendered on and after November 1, 2022 and shall continue as a ~~five-year~~ pilot which will end on October 31, ~~2027~~2032, unless affirmatively extended or otherwise permitted by Commission Order. **(C)**

WNA is a distribution charge adjustment and is considered a basic service charge.

Calculated WNA amounts shall be subject to Rider A – State Tax Adjustment Surcharge and Rider I – Distribution System Improvement Charge. No additional riders or surcharges will be applied to the calculated WNA.

Calculation of Adjustment Amount:

The WNA will be applied to October through May billing cycles and shall be calculated on a customer account specific basis in accordance with the formula below:

WNBC = BLMC + [((NHDD +/- (NHDD * 3%)) / AHDD) x (AMC-BLMC)]
WNAC = WNBC – AMC
WNA = WNAC x Distribution Charge

(a) Weather Normalized Billing Ccfs("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of the Normal Heating Degree Days ("NHDD", adjusted for a 3% deadband as further discussed in subparts (i) and (j) below), divided by the Actual Heating Degree Days ("AHDD") and the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.

(b) BLMC shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a thirty-six-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent thirty-six months of bill history. If less than twelve months of bill history is available for the premise, an average base load for the related customer class will be applied.

(c) AMC shall be measured for each customer and billing cycle and will be inclusive of any heating value corrections.

(d) NHDD shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's ~~15~~10-year average for the given day. **(C)** NHDD shall be updated every ~~5 years~~rate case using the methodology established in the Company's general rate case proceeding at ~~R-2021-3030218~~R-2025-3059523~~ with the next scheduled update of the NHDD to be effective on October 1, 2025, and thereafter every five years~~.

(C) Indicates Change

RULES AND REGULATIONS

13. RIDER D

MERCHANT FUNCTION CHARGE

Applicability and Purpose

This Rider shall be applied to rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. The Rider is equal to the fixed percentage, established by the PUC in Company's last general base rate proceeding, of purchased gas costs which are expected to be uncollectible, and shall not be reconciled to reflect actual results. Rider D is intended to make Company's Price to Compare more comparable to the gas supply service prices offered of other Natural Gas Suppliers that presumably reflect anticipated uncollectible expenses.

Rider D Charge

Rider D charges shall be equal to 2.~~56~~37% for Residential PGC Customers and 0.~~56~~47%**(~~I~~D)** for Non-Residential PGC Customers of Rider B (Purchased Gas Costs).

The collection of the Rider D charges will be summarized by Rate Schedule sub-accounts in the Gas Operating Revenue FERC Account No. 480000 for Rate R and 481000 for Rates N. The associated costs are recorded in FERC Account Nos. 904001 and 904002.

(~~I~~D) Indicates ~~Increase~~Decrease

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	**Rate N (MCF)**	
Annual C-Factor	$ 0.62323	$ 6.2323	~~(D)~~
Annual E-Factor	$ 0.05163	$ 0.5163	~~(I)~~
Gas Procurement Charge	$ 0.00660	$ 0.0660	
Merchant Function Charge	$ 0.~~01728~~ 01599	$ 0.~~0378~~ 0317	(~~I~~D)
Total Price to Compare	$ 0.~~69874~~ 69745	$ 6.~~8524~~ 8463	(~~I~~D)

(D) Indicates Decrease
~~**(I) Indicates Increase**~~

RULES AND REGULATIONS

16. RIDER F

UNIVERSAL SERVICE PROGRAM

APPLICABILITY AND PURPOSE

This Rider shall be applicable to all residential customers except customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs. This rider may also apply to customers receiving service under Rate XD on a negotiated rate basis. **(C)**

RATE

In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each MCF of sales volumes or distribution volumes distributed by the Company to customers receiving service under Rate Schedules R and RT. The USP rate for customers receiving service under Rate XD, if applicable, may differ from the USP rate stated below and may be applied on a volumetric, fixed charge, percentage or other basis. **(C)**

The USP rate for Rate R and Rate RT: $0.6363/Mcf **(~~I~~C)**

The USP rate for Rate XD: as negotiated, but no greater than the above rate. **(C)**

CALCULATION OF RATE

The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low-income program that is implemented during the period that the Rider is in effect.

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include
1) the projected CAP credit
2) projected CAP customer application and administrative costs; and
3) projected CAP pre-program arrearage forgiveness.

CAP Credit shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes.

(~~I~~C) Indicates ~~Increase~~Change

RULES AND REGULATIONS

16. RIDER F - Continued

UNIVERSAL SERVICE PROGRAM

QUARTERLY ADJUSTMENT

Any time that the Company makes a change in base rates or PGC rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION

On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP and actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 9.2% adjustment for amounts granted to participants in excess of 25,404 (the number of CAP enrollees as of September 30, 20265). The 9.2% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following: (C)

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits in excess of the number of CAP enrollees as of September 30, 2026 exceeding 25,404 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0920 in order to determine the amount of the CAP Credits which will not be recovered through Rider USP. (C)

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness in excess of the number of CAP enrollees as of September 30, 2026 exceeding 25,404 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0920 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP. (C)

(C) Indicates Change

RULES AND REGULATIONS

19. Rider I

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.~~33~~00% will apply. **(~~I~~D)**

19.A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

19.A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Piping, Couplings, Valves, Excess Flow Valves, Risers - Distribution & Transmission. (Accts. 374, 376, 365, 367)
- Measuring & Regulator Stations – Distribution & Transmission (Accts. 375, 378, 379, 366, 369, 370)
- Gas Service Lines and Insulated and Non-Insulated Fittings (Accts. 378, 380)
- Meters, Meter Bars, Meter Installations (Accts. 381, 382)
- House Regulators & Installations (Accts. 383, 384)
- Industrial & Farm Tap Measuring & Regulator Station Equipment (Accts. 385, 386)
- Miscellaneous Equipment and Material– Distribution & Transmission (Accts. 387, 371)
- Equipment – Electronic Systems & Software (Accts. 391)
- Vehicles, Power Equipment, Tools, Shop & Garage Equipment (Accts. 392, 394, 396)
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities.
- Gathering lines (Accts. 332)
- Storage lines (Accts. 353)
- Other related capitalized costs.

19.A.3 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

(~~I~~D) Indicates ~~Increase~~Decrease

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS **(C)**
~~**Effective November 1, 2020**~~

22.1 Application of Rates ~~(C)~~

(a) Applicable Rates: DS, LFD, XD and IS.

(b) Notification of Delivery; Nomination Procedures. Customer shall notify the Company of any and all gas deliveries to the Company's system, including, but not limited to, the provision of nomination, revised nomination and scheduling information, in accordance with the Company's *Nomination Procedure*, as may be amended from time to time, and made available on the Company's Gas Management Website ("Nomination Procedure"). The quantity of gas received on behalf of the Customer shall be determined by allocation or other method by the Company if required in its sole discretion. It is the Customer's responsibility to arrange that any necessary billing information be provided to the Company and/or delivery gas source.

(c) Nominating Agents. A Customer shall notify the Company of its designated nominating agent ("Agent") for purposes of nominating the volumes of natural gas to be delivered to the Company's system on the Customer's behalf in accordance with the Nomination Procedures. Customer shall notify Company, on a form designated by the Company in the Nomination Procedures, of the responsibilities of the Agent, and shall provide Company with the Agent's valid e-mail address and valid 24-hour contact information. Customer shall remain liable for all charges and penalties notwithstanding Customer's designation and use of an Agent in accordance with the provisions herein.

(d) Penalties for Customer's Default. Customers failing to provide nomination, billing, scheduling, agent, supplier and/or other required information to the Company or pipeline(s)in accordance with the provisions of the Tariff, or otherwise failing to comply with the Company's *Nomination Procedure*, shall be subject to applicable imbalance charges and, in addition, be charged an Administrative Scheduling Fee in an amount no greater than $1,000 per day for every day such required information is delayed. If a Customer default of these provisions occurs and is occurring for a period of 90 days, the Company may impose retail or standby rates on the Customer's account beginning the first day after such 90-day period through and until such time as the Company deems the Customer default to have been resolved.

(e) Sequencing for Billing. Unless otherwise agreed by the Company and the Customer, customer-owned gas delivered under the transportation rate schedules shall be sequenced for billing as the first gas through the meter, and gas purchased under the Retail and Standby Rider shall be sequenced for billing purposes as the last gas through the meter. Gas billed under firm rate schedules shall be billed prior to gas billed under interruptible rate schedules. In lieu of otherwise specified tariff provisions, where the Company and Customer agree, Company shall use pipeline metering facilities for measuring and billing total deliveries to the Customer's facility.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS ~~Effective November 1, 2020~~ – Continued **(C)**

(f) Payment of Charges, Penalties. The Customer shall pay the Company for any and all additional charges incurred on the Customer's behalf or resulting from the Customer's actions or inactions which the Company can demonstrate arise out of the provision of transportation service including, but not limited to, pipeline transportation and service charges. Any such charge, penalty or obligation imposed by a pipeline transporter or supplier as result of balancing of gas delivered to the Customer shall be paid by the Customer in addition to otherwise applicable charges.

(g) The Billing Pool Agent is required to notify Company at least ten days prior to dropping a Customer from a Billing Pool. If adequate advance notice is not provided, the Company reserves the right to not drop the Customer from the Billing Pool.

(h) Billing Pools. One or more transportation Customers may join together in pooled transactions for the purchase and delivery of gas. The Company may allocate among all such customers the volumes of gas or imbalances for purposes of determining responsibility for charges, rates, penalties or other obligations imposed by the Company, or in connection with operation of the pool. A Supplier to a Billing Pool must notify the Company prior to initiating gas deliveries. A Customer is required to submit in writing a request for entry into a Billing Pool.

(1) Each Billing Pool shall appoint an Agent who will coordinate nomination, billing, reconciliation, allocation and any other necessary communication between the Billing Pool and the Company.

(2) All members of a Billing Pool shall be of like balancing service election. The Company may restrict formation or operation of any Billing Pool in order to meet like balancing service election or pipeline imposed eligibility requirements.

(3) Automated Meter Reading. The Company has the right as a condition of being a pool member, to install, at the Customer's expense, automated meter reading ("AMR") equipment for the purposes of daily collection or monitoring, and billing Customer volumes at each related service meter. Where AMR equipment is installed, the Customer shall maintain, at its expense, unless otherwise directed by the Company, a dedicated phone connection and electric service to the AMR equipment which will allow the Company unlimited remote access to the AMR device at all times. Failure to maintain a required phone and/or electric service may result in Customer being removed from a Billing Pool and being placed on a rate schedule not requiring daily measurement capability.

(4) Service under Rate NNS is required by, and shall be individually billed to, any and all members of a Billing Pool except when all pool members are monitored on a daily basis through the use of Company owned AMR equipment at all meter locations. Additionally, service under Rate MBS is required by, and shall be individually billed to, any and all members of a Billing Pool when the billing month for each pool member does not end on the same calendar date; Billing Pools having all customers monitored and billed through the use of Company owned AMR equipment at all meter locations shall be exempt from this requirement.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS ~~Effective November 1, 2020~~ – Continued **(C)**

(i) Recognition of Supplies. Volumes transported on behalf of the Customer will be recognized in the Customer's current billing month based on nominated or scheduled volumes information and may be adjusted after notification is received from the pipeline supplier(s) of the volumes transported on behalf of the Customer. Volumes scheduled shall be determined on the basis of best available actual or confirmed pipeline and/or Company information at the time of billing.

(j) Unless otherwise negotiated under Rate XD, the Company shall retain for Company use gas, and lost and unaccounted for gas, 1.5% of the total volume of ~~(I)~~ gas delivered into its system for the Customer's account.

22.2 Balancing and No-Notice Service.

(a) Each Customer shall use best efforts to balance purchases, deliveries and receipts of gas at all times. Except as specified in 22.1(f), for the purposes of balancing excess deliveries and shortfalls and purchasing services under Rates NNS and MBS, Billing Pools may be treated as a single entity. Subject to the terms and conditions set forth below, the Company shall provide no-notice and monthly balancing services under Rate Schedules NNS and MBS. Service under Rate Schedules NNS and MBS is available only for inadvertent fluctuations, limited by the terms and conditions of each Rate Schedule, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. In the event the Customer fails to use best efforts to balance deliveries and receipts, or otherwise misuses no-notice or balancing services as determined by the Company in its sole discretion, Section 22.4 shall apply for the period of such default or misuse.

(b) Daily Balancing. The Company shall allow Customer's daily demand to inadvertently vary from daily scheduled deliveries by +/-4.5% without imposing Daily Balancing Charges, provided the total daily quantity taken does not exceed Customer's Daily Firm Requirement, MDQ or otherwise specified contract demand limit. Daily imbalances in excess of the +/-4.5% tolerance, unless otherwise provided by service elected under Rate NNS, shall be assessed a Maximum Daily Excess Balancing Charge in accordance with Section 22.4 under Critical Day and Non-Critical Day criteria unless otherwise specified in Customer's contract, in addition to the charges specified in Rates DS, LFD, XD and IS, on all such quantities.

(c) Imbalance Resolution. Customer's monthly imbalances will be calculated at the end of each billing period to determine if any overdelivery (excess) or underdelivery (shortfall) condition exists for volumes scheduled versus volumes metered. If the Customer is determined to be in an imbalance condition, and has not elected service under Rate MBS or has exceeded the 10% imbalance allowance provided under Rate MBS, then the Company shall sell and the Customer shall buy, subject to the 5 percent limitation under Rate MBS, any shortfall amount according to the following cash-out pricing:

(~~I~~C) Indicates ~~Increase~~Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
~~Effective November 1, 2020~~ – Continued **(C)**

Shortfall Percent	Cash-Out Price ~~(C)~~
Up to 5%	Shortfall Monthly Reference Price("SMRP")
Greater than 5%, but not greater than 15%	SMRP x 1.1
Greater than 15%, but not greater than 25%	SMRP x 1.3
Greater than 25%	SMRP x 1.5

Likewise, the Customer shall sell, and the Company shall buy any excess amount according to the following cash-out pricing:

Excess Percent	Cash-Out Price ~~(C)~~
Up to 5%	Excess Monthly Reference Price("EMRP")
Greater than 5%, but not greater than 15%	EMRP x 0.9
Greater than 15%, but not greater than 25%	EMRP x 0.7
Greater than 25%	EMRP x 0.5

The SMRP (Shortfall Monthly Reference Price) shall be the average of the DPP midpoint ~~(C)~~
Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price ~~(C)~~
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The EMRP (Excess Monthly Reference Price) shall be the average of the DPP midpoint ~~(C)~~
Reference Prices corresponding to the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Reference Price ~~(C)~~
North	Tennessee, zone 4-300 leg
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS ~~Effective November 1, 2020~~ – Continued **(C)**

Customer Delivery Region shall be assigned to each Customer in accordance with Customer's delivery location within the Company's distribution system.

The SMRP and EMRP are applicable to the above tables only for inadvertent monthly imbalances. The HMRP (Highest Monthly Reference Price) or the LMRP (Lowest Monthly Reference Price) as defined below shall apply respectively to shortfall and excess conditions in those situations where intentional imbalances are involved. ~~(C)~~

The HMRP shall be calculated as the highest of the DPP absolute Reference Prices for the Customer's Delivery Region during the Customer's billing month as listed below: ~~(C)~~

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

~~(C)~~

The LMRP shall be calculated as the lowest DPP absolute reference prices for the Customer's Delivery Region during the Customer's billing month as listed below: ~~(C)~~

Delivery Region	Reference Price
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

~~(C)~~

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
~~Effective November 1, 2020~~ – Continued **(C)**

(d) The Company may extend the balancing period for gas volumes and may increase volumes eligible for balancing in its discretion, but only if it determines that such action is consistent with its obligations to other customers.

(e) Supply Transfers. In order to facilitate Monthly balancing related to inadvertent imbalances in Company's sole discretion, the Company shall allow Supply Transfers among Customers and Billing Pools, Customers-to-Billing Pools and Billing Pools-to-Customers at a fee of $125 per transaction, provided however: (1) such transfer is requested prior to the end of the billing month for both the transferee and the transferor, (2) such transfer is physically possible given pipeline interconnection and delivery point limitations which require transfers to be between parties located on the same segment of the Company's distribution system, and system supplies, and reliability are not adversely affected.

(f) Competitive Volume Customers. In the case of Customers or applicants seeking service for facilities with a design volume capability allowing for direct connection to transmission or gathering lines for bypass of Company facilities, Company shall have the right to establish daily and monthly balancing tolerances at levels other than those specified in subsections (b) and (c) of this Section 22.2 to reflect specific operational limitations or to protect the interests of other Customers, as determined by the Company in its sole discretion. Additionally, the Company may establish special nomination rules, imbalance resolution rules and communication protocols that reflect the Customer's or applicant's commercial alternatives, and which are consistent with its obligations to other Customers.

22.3 Service Agreement and General. ~~(C)~~

(a) Limitation on Liability.

(1) The Company shall not be liable for curtailment of service under Rates DS, LFD, XD and IS, or loss of the Customer's gas as a result of any steps taken to comply with any law, regulation or order of any governmental agency with jurisdiction to regulate, allocate or control gas supplies or the rendition of service hereunder, and regardless of any defect in such law, regulation or order.

(2) Gas transported and delivered by the Company to the Customer hereunder shall be and remain the property of the Customer. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during and after receipt by the Company.

(3) The Company shall not be liable for any loss to the Customer arising from or out of service hereunder, including loss of gas in the possession of the Company or any other cause, except gross or willful negligence of the Company's own employees or agents. The Company reserves the right to commingle gas of the Customer with other supplies.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS ~~Effective November 1, 2020~~ – Continued **(C)**

(b) Warranty, indemnity and special provisions. The receipt of service constitutes Customer's agreement to the following representations and warranties, together with related provisions in the service agreement:

(1) clear and marketable title to the Customer's gas;
(2) delivery points, pressure, quality and other specifications acceptable to gas transmission pipeline(s) and the Company;
(3) eligibility of the Customer for service;
(4) existence of lawful authority for sale, transportation and delivery;
(5) agreement to pay all excise, sales, use, gross receipts, or other taxes (other than income taxes), all tariff charges and all penalties, charges, fees for transportation, balancing etc., associated with delivered gas, which may be levied upon or incurred by the Company at any time;
(6) agreement to indemnify and hold the Company harmless from breach of representations or warranties, and any liability associated with Customer's gas while on the Company's system.

Copy of Gas Purchase Agreements, Other Documents. When requested by the Company, the Customer shall provide the Company with a copy of Customer's gas purchase contract and any related transportation, marketing and brokerage contracts, or, in lieu of providing such contracts, certify pertinent information as required by the Company, and, in order to meet state or federal requirements, provide a sworn affidavit setting forth the Customer's cost of gas for the period requested by the Company. The Company shall endeavor to protect the confidentiality of information provided by the customer in accordance with this provision. The Company will provide such information to third parties only when required to do so by law, regulation or order and in such case, will attempt to maintain confidentiality to the extent possible.

22.4 Maximum Daily Excess Balancing Charge

The Daily Excess Balancing Charge that occurs on Critical Days shall be as follows:

The charge for exceeding daily balancing limits shall be ten times the highest price in the DPP for each delivery region as listed in the following table. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into Pennsylvania. ~~(C)~~

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
~~Effective November 1, 2020~~ – Continued **(C)**

Delivery Region	Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.
Central	The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco Zone 6 to Zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

~~(C)~~

The Daily Excess Balancing Charge that occurs on Non-Critical Days shall be as follows:

Daily Imbalance Percent	Penalty
Up to 15%	DRP
Greater than 15%, but not greater than 30%	DRP x 2
Greater than 30%, but not greater than 45%	DRP x 3
Greater than 45%, but not greater than 60%	DRP x 4
Greater than 60%	DRP x 5
Intentional imbalances	DRP x 5

~~(C)~~

The DRP (Daily Reference Price) shall be equal to the difference in price between the highest DPP Reference Price and the lowest DPP Reference Price for the Customer's Delivery Region as listed below but shall not be lower than $0.25/Mcf. ~~(C)~~

Delivery Region	Highest Reference Price	Lowest Reference Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.	Tennessee, zone 4- 300 leg
Central	Transco zone 6, non-N.Y.	Transco, Leidy line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

~~(C)~~

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS ~~Effective November 1, 2020~~ – Continued **(C)**

The Company shall not charge any Maximum Daily Excess Balancing Charges if the Customer's Excess Daily Imbalance is anticipated to benefit the distribution systems daily balancing position as determined by Company in its sole discretion.

22.5 Operational Flow Orders and Daily Flow Directives

The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Twenty-Five ($25) per Mcf or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater.

22.6 Cost of Assigned Capacity.

In addition to applicable interstate pipeline demand charges, the associated demand charges to customers, or their NGS, served under Rates DS, LFD, XD, and who ~~(C)~~ utilize assigned PGC capacity and pay weighted average cost, will include 100% (DS) and 50% (LFD, XD) pro rata allocation of annual Peaking Supply service demand costs. The associated demand charges will be reduced by a pro rata share of the Economic Benefit of Peaking Supply (EBPS Credit). The EBPS Credit shall mean a pro rata share of (a) the value of Peaking Supply utilized in off system sales transactions and included in the PGC share of the Revenue Sharing Incentive Mechanism revenues, plus (b) the Commodity Price Differential, which shall be, as measured for the date of Peaking Supply delivery, the aggregate difference, if positive, between the DPP Reference Price applicable to the zone of delivery ~~(C)~~ (i.e., Texas Eastern M3 for deliveries in the South and West Delivery Regions with the exception of deliveries from Mt. Bethel and Transco Z6 NNY for deliveries made in the North and Central Delivery Regions and deliveries from Mt. Bethel) and the actual price paid for actual Peaking Supply deliveries into the UGI distribution system. The EBPS Credit shall be applied in the calculation of associated demand charges in the second billing month after the credit has accrued (e.g., December accrued credits will be used to reduce the February associated demand charges) and shall not, on an annual basis, exceed the annual incremental demand charges for ~~(C)~~ Peaking Services charged to Rate DS, LFD, and XD customers, or their NGS, as described above.

(C) Indicates Change

RATE R

GENERAL SERVICE – RESIDENTIAL

AVAILABILITY

This rate applies to all Residential Customers in the entire gas service territory of the Company and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $~~16.25~~23.00 per customer **(I)**

Plus Distribution Charge: $0.~~6331~~68383/Ccf **(~~C~~I)**

Plus SURCHARGES and RIDERS

Rider A – State Tax Adjustment Surcharge
Rider B – Section 1307 (f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment
Rider D – Merchant Function
Rider E – Gas Procurement Charge
Rider F – Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RATE RT

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies to all Residential Customers in the entire gas service territory who are served by a qualified Choice Supplier receiving service under Rate AG and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $~~16.25~~23.00 per customer **(I)**

Plus Distribution Charge: $0.~~6331~~68383/Ccf **(~~C~~,I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C - Weather Normalization Adjustment
Rider F - Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase ~~(C) Indicates Change~~

RATE GL

GENERAL SERVICE - GAS LIGHT SERVICE

AVAILABILITY

This service is available for street, highway, driveway or other lighting or sign illumination, where measurement by meter of the gas consumed is not practicable or economical. As used herein, "light" means a single lamp or sign having one (1) gas-flow orifice and one (1) or more mantles, and of a type approved by the Company.

MONTHLY RATE TABLE

Distribution Charge: $0.~~6331~~68383/Ccf **(~~C,~~I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B – Section 1307(f) Purchased Gas Cost
Rider I – Distribution System Improvement Charge

Monthly usage is assumed to be 1.8 Mcf, however, for larger consumption input fixtures, the Company reserves the right to modify.

BILLS DUE

All bills for continuing service are due each month when rendered, and the final due date stated on the bill shall be no less than fifteen (15) days from the date of presentation. Upon discontinuance of service, bills are due and payable upon presentation.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

SPECIAL TERMS AND CONDITIONS

Gas will be supplied to lights furnished, erected and maintained by the customer only when equipped with regulators and such devices as the Company considers necessary for turning lights on and off for maintenance and safety purposes.

(I) Indicates Increase **~~(C) Indicates Change~~**

RATE N

GENERAL SERVICE – NON-RESIDENTIAL

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Non-Residential Customers, using gas for any purpose including gas purchased by another public utility for resale. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate N service may not be applied to supplement or back up any transportation service.

MONTHLY RATE TABLE

Customer Charge: $~~36.42~~39.00 per customer **(I)**

Plus Distribution Charge: $~~4.3004~~5.0297/Mcf **(~~C,~~ I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B - Section 1307(f) Purchased Gas Cost
Rider C - Weather Normalization Adjustment
Rider D - Merchant Function Rider
Rider E - Gas Procurement Charge
Rider G - Energy Efficiency and Conservation
Rider H - Technology and Economic Development
Rider I - Distribution System Improvement Charge

MINIMUM CHARGE
The Customer Charge as set forth above.

MINIMUM BILL PROVISION
If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT
In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase **~~(C) Indicates Change~~**

RATE NT

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Customers who are served by a Choice Supplier receiving service under Rate AG, except residential Customers, using gas for any purpose. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate NT service may not be applied to supplement or back up any transportation or retail service.

MONTHLY RATE TABLE

Customer Charge: $~~36.42~~39.00 per customer **(I)**

Plus Distribution Charge: $~~4.3004~~5.0297/Mcf **(~~C,~~ I)**

Plus SURCHARGES and RIDERS

Rider A – State Tax Adjustment Surcharge
Rider C – Weather Normalization Adjustment
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

The Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase **~~(C) Indicates Change~~**

RATE DS

DELIVERY SERVICE

AVAILABILITY

This service applies in the entire territory served by the Company. Firm Delivery Service shall be provided for all volumes supplied by the Customer for which the Company has available on system delivery capacity, subject to Section 21 - Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

The Customer must execute a Service Agreement for not less than (1) one year. The contract shall continue in force for consecutive (1) year periods unless cancelled by the Customer upon ninety (90) days written notice to Company prior to the expiration of a contract term.

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable delivery service balancing provisions or in accordance with optionally elected and approved balancing or standby services.

Service under Rate DS is subject to the terms set forth under Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Capacity Charge if applicable, and the Distribution Charge as described below. The following are maximum rates.

Customer Charge: $~~300.00~~353.00 per month **(I)**

Plus Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected MDQ.

Plus Maximum Distribution Charge: $3.~~3651~~3652/Mcf **(~~C,~~I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

~~**(C) Indicates Change**~~
(I) Indicates Increase

RATE MBS - Continued

MONTHLY BALANCING SERVICE

MONTHLY RATE TABLE

Monthly Transportation Volume

Rate DS/IS	$0.~~0177~~0198/Mcf x Monthly Billed Volumes	**(I)**
Rate LFD	$0.~~0103~~0113/Mcf x Monthly Billed Volumes	**(I)**
Rate XD	$0.~~0104~~0116/Mcf x Monthly Billed Volumes	**(I)**

The Company will update the average monthly imbalance utilized in the development of Rate MBS charges annually with the actual average monthly imbalance for the 12-month period ending September to determine the new Rate MBS charges effective December 1 each year. The Company shall include the new Rate MBS charges as part of its annual PGC compliance filing.

(I) Indicates Increase

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Demand Charge, the Capacity Charge (if applicable), the Distribution Charge and any Excess Take Charge as described below. The following are maximum rates.

Customer Charge: $670.00 ~~(I)~~

Plus
Maximum Demand Charge: $7.6956/Mcf of Customer's elected DFR. ~~(I)~~

Plus
Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected DFR. Applicable only when the customer elects UGI capacity.

Plus
Maximum Distribution Charge (all volumes): $1.~~3831~~4173/Mcf **(I~~,C~~)**

Plus
SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I - Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

RETAINAGE RATE

Company Use and Unaccounted for Gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j).

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

EXCESS TAKE CHARGE

Except as provided in the Company's *Nomination Procedure*, for authorized usage on any day in excess of the Daily Firm Requirement there will be a charge of $6.00 per MCF in addition to the charges specified in the rate table.

(I) Indicates Increase
~~**(C) Indicates Change**~~

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge, Demand Charge, Capacity Charge (if applicable), and Charge for Other Transportation.

Annual: Unless a higher amount is agreed upon by the Company and Customer, the Minimum Annual Bill shall be based on the Customer maintaining a 0.50 annual load factor and shall be due and payable with the bill for the 12th month in the contract year. The Customer's actual load factor shall be determined by dividing the total volume of gas taken during the contract year (including volumes taken under the Retail and Standby Rider, and the Cash-Out provisions of Section 22.2) by the sum of the Daily Firm Requirements for the contract year. If the actual load factor is less than 0.50, then, in addition to payment for actual usage, the Customer shall pay a Minimum Annual Bill charge equal to the product of: (1) the difference between 0.50 and the actual load factor, (2) the sum of the Customer's Daily Firm Requirements for the contract year, and (3) the average delivery charge paid by the Customer over the previous 12-month period, as calculated by the Company. If the Customer's actual load factor is greater than or equal to 0.50, no Minimum Annual Bill charge will be required. **(C)**

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company. Such charges related to the use of Customer elected and Company provided transportation capacity shall be reflected directly on the Customer's bill for service rendered on and after April 1, 2024, pursuant to Commission order at Docket R-2023-3040290, with such charges labeled on the bill as Capacity Charge.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Fifty Dollars($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Section 22.4 is primarily intended to establish applicable daily imbalance penalty charges but shall also provide for the pricing applicable to any Unauthorized Overrun volumes, which shall be subject to the same pricing as an Intentional imbalance. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun. ~~(I)~~ ~~(C)~~ ~~(C)~~

SERVICE UNDER OTHER RATES

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purposes of determining Excess Take Charge and Unauthorized Overrun gas.

(C) Indicates Change ~~**(I) Indicates Increase**~~

RATE XD -Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be negotiable and shall be the sum of the Customer Charge, Distribution Charge, Demand Charge if applicable, the Capacity Charge (if applicable), and the Minimum Annual Bill as described below. ~~(C)~~

The following are maximum rates.

Customer Charge: Charge as determined by negotiation.

Plus
Maximum Demand Charge: Charge as determined by negotiation.

Plus ~~(C)~~
Capacity Charge: On or after October 28, 2025 when current Rate XD contracts expire, Capacity available for Customer use, and related Capacity Charge, shall be as specified within Customer's service contract, provided Company has available capacity and Company and Customer agree to related terms. For Customers electing Company capacity, such Capacity Charge shall be charged at the Company's unitized weighted average cost of firm transportation capacity per elected DFR. However, for Customers specifically receiving assignment of Columbia Pipeline capacity via agreement with the Company and through capacity release, such Customers, or their NGS, shall pay capacity charges direct to Columbia in accordance with such release. For Customers not receiving any Company capacity, no Capacity Charge will apply.

Plus
Maximum Average Delivery Charge: $1.~~3831~~4173/Mcf **(~~C~~,I)**

Plus **(C)**
SURCHARGES and RIDERS where negotiated

(C)
Rider F – Universal Service Program
Rider I – Distribution System Improvement Charge

RETAINAGE RATE

Unless otherwise agreed between the Customer and the Company, Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j)

MINIMUM BILL

Minimum Bill Volumes and terms shall be defined in the Service Agreement and determined by negotiation.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the Customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

(C) Indicates Change (I) Indicates Increase

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Aggregation Service

Issued: ~~November 26, 2025~~January 28, 2026

Effective for service rendered on and after ~~December 1, 2025~~March 29, 2026~~, filed in Compliance with the Order of the Pennsylvania Public Utility Commission, entered on September 25, 2025 at Docket No. R-2025-3054938.~~

Issued By:

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This supplement makes increases and changes to existing rates (see page 2(b)).

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.12 If a Choice Supplier elects to participate in the Company's POR Program, the Choice Supplier must enter into a POR Agreement for the rate classes that it serves that will be included in the POR. The elected Rate Classes shall be one of the following: (1) RT only, (2) NT only, or (3) RT and NT. All receivables associated with basic natural gas supply services in the specific rate class, subject to the rate class elections made above, must be sold by the participating Supplier to the Utility. For the purposes of this provision, the phrase "basic natural gas supply services" shall include charges directly related to the physical delivery of natural gas to a retail customer but shall not include charges for "carbon-neutral" products, appliance maintenance service, energy efficiency services, termination or cancellation fees, security deposits or other products or services not directly related to the physical delivery of natural gas to a retail customer. Customer accounts that are billed for non-basic natural gas supply services will not be eligible for UGI's POR program. All of the NGS' customer accounts within the elected Rate Classes (subject to the volumetric limits contained in section 5.4) must be POR eligible accounts, with the exception of customers that purchase carbon-neutral products. NGSs may choose to use UGI consolidated billing for Non-POR eligible customers who are purchasing bundled "carbon-neutral" product offerings. The termination and reconnection provisions of Chapters 14 and 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing. UGI shall support rate-ready billing, and all NGS rates must conform to supported rate designs. For Purchased Customer Accounts, Company shall pay Choice Supplier an amount equal to 97.~~30~~49% for residential amounts billed (inclusive of associated sales taxes) and 99.~~30~~39% of non-residential amounts billed (also inclusive of taxes). Customer participation for NT shall be subject to Volumetric Eligibility pursuant to Section 5.4. ~~(C)~~ (C) (C)

4.13 All existing customers of Choice Suppliers who elect to participate in the Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier and Company that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

All new customers enrolling with Choice Suppliers who are participating in Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier prior to enrollment, and by Company upon enrollment, that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

(C) Indicates Change

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 2-R

Rebuttal Testimony of
Tracy A. Hazenstab

Topics Addressed: **UGI Gas Exhibit A – Fully Projected Operating Expenses & Revenues**

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 2, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain components of the Company's filing, based on the information provided during the discovery phase of this proceeding. In addition, my testimony responds to certain portions of the direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission" or "PUC") Bureau of Investigation and Enforcement's ("I&E") witness Zachari Walker (I&E Statement No. 1) and the Office of Consumer Advocate's ("OCA") witness Jennifer Rogers (OCA Statement 2).

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. As discussed below, I am sponsoring the Company's accounting exhibit, UGI Gas Exhibit A - Fully Projected (REBUTTAL), which reflects all of the updates and corrections to the Company's claim identified to date.

II. UPDATES AND CORRECTIONS TO COMPANY'S CLAIM

Q. Since the filing of your direct testimony, has the Company identified any operations and maintenance expense ("O&M") components of its filing that should be updated?

A. Yes, the Company has identified the following O&M items that required revision for the fully projected future test year ending September 30, 2027 ("FPFTY"):

- Embedded Cost of Long-Term Debt: The interest rate for the term loan to be issued in the FPFTY is increasing from 3.098% to 4.9%. The prior rate reflected expectations of Federal Reserve rate cuts reducing the Term SOFR benchmark by first quarter 2027; however, market expectations have since shifted toward a sustained elevated rate environment, resulting in an increased interest rate estimate. This revision increased the weighted cost of debt from 5.17% to 5.22% and increased the revenue requirement by approximately $870,000. In addition, a revised Schedule B-6 (Cost of Debt) and Schedule B-7 (Rate of Return) are provided to represent these increases.

- Payroll Adjustment: As explained in the rebuttal testimony of Vivian K. Ressler (UGI Gas Statement No. 4-R), the Company accepts I&E's recommended adjustment in the amount of ($1,153,000) to reflect a three-year average of the historic vacancy rate. This adjustment is reflected in Line 19, Administrative & General Expense, on Schedule D-2 and decreases the revenue requirement by ($1,201,000) after cash working capital calculations.

- Employee Benefits: As explained in the rebuttal testimony of Ms. Ressler, the Company accepts I&E's recommended adjustment in the amount of ($764,000) to reflect a three-year average of the historic vacancy rate. This adjustment is reflected in Line 19, Administrative & General Expense, on Schedule D-2 and decreases the revenue requirement by ($784,000) after cash working capital calculations.

- Payroll Taxes: The Company accepts I&E's payroll tax adjustment in the amount of ($88,000), which is due to the acceptance of the vacancy rate adjustment and is discussed in Ms. Ressler's rebuttal. This adjustment is reflected in Line 21, Taxes other than Income, on Schedule D-2 and decreases the revenue requirement by ($90,000) after cash working capital calculations.

- OPEB Expense: As explained in the Company's response to I&E-RE-29, the amortization of the regulatory liability for past over-recovery of the post-retirement welfare plan will terminate at the end of the future test year ("FTY"). In the Company's claim, this amortization income was inadvertently included in the FPFTY, creating an understatement in the Company's claim of $974,464. This adjustment is reflected in Line 19, Administrative & General Expense, on Schedule D-2 and increases the revenue requirement by $991,000 after cash working capital calculations. Further

discussion can be found in the rebuttal of Amy M. Keller (UGI Gas Statement No. 5-R).

Q. Since the filing of your direct testimony, has the Company identified any revenue components of its filing that should be updated?

A. Yes, the Company identified the following revenue item that requires revision for the FPFTY:

- Use Per Customer Adjustment: The Company is accepting the adjustment to use per customer as outlined in the Direct Testimony of Ethan H. Cline (I&E St. 3, at pp. 8-9) and explained in the rebuttal testimony of Sherry A. Epler (UGI Gas Statement No. 10-R). Total revenue is increasing by $1,037,436, margin is increasing by $483,884, and cost of commodity is increasing by $553,552. Included in the total cost of commodity adjustment is the Purchase Gas Cost ("PGC") annualization increase of $495,065 as reflected on Schedules D-5 and D-6 and increases in the adjusted budgets for Universal Service Program ("USP") expense and Energy Efficiency and Conservation ("EEC") expense of $44,255 (Schedule D-16) and $14,231 (Schedule D-19) respectively.

As with the updates to the Company's costs, these revisions to the Company's revenues, including the breakout between margin and cost elements, are reflected in UGI Gas Exhibit A – Fully Projected (REBUTTAL).

Q. Based upon the adjustment analyses conducted by the Company, what do you conclude?

A. As set forth in UGI Gas Exhibit A - Fully Projected (REBUTTAL), the overall effect of the updates and corrections to the Company's claim is that the Company supports a revenue increase of $98,693,000 (as compared to the as-filed claim of $99,368,000) using the Company's proposed capital structure, revised weighted average cost of debt, and proposed return on equity of 10.75%. The Company's revisions to accept certain adjustments recommended by I&E and OCA in particular have been adopted to decrease its overall claim.

III. REVENUE REQUIREMENT ADJUSTMENTS

Q. Do any of the other parties propose adjustments to the Company's overall revenue requirement?

A. Yes. I&E recommended a revenue requirement of $1,288,531,000, which represents an increase of $53,385,000 to I&E's adjusted present rate revenues of $1,235,146,000. I&E St. No. 1, at p. 4. OCA recommended a revenue requirement of $1,218,849,000, which represents a decrease of $15,833,000 to OCA's adjusted present rate revenues of $1,234,682,000. OCA St. 2; Schedule JLR-1. The Office of Small Business Advocate ("OSBA") did not provide any recommendation on revenue requirement.

Q. Please summarize I&E's and OCA's proposed adjustments.

A. I&E's recommended revenue requirement includes a net decrease of $14,199,000 to O&M expenses, a reduction of $88,000 to payroll taxes, a total reduction of $3,115,000 to rate base, a total increase of $464,481 to present rate revenue, the use of the capital structure proposed by the Company, and a return on equity of 9.81%. OCA's recommended revenue requirement includes a total reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to O&M expenses, a reduction of $88,000 to payroll taxes, a total decrease to depreciation expense of $21,800,000, a $18,039,000 increase to rate base, and the use of the capital structure that consists of 51% debt and 49% equity, and a return on equity of 8.80%.

Q. Does the Company agree with OCA's or I&E's proposed adjustments to the Company's revenue requirement?

A. No. As explained throughout this testimony and the other rebuttal testimony forming UGI Gas's rebuttal position, with the exception of certain updates to the Company's revised filing and the acceptance of some relatively minor operating expense and rate base adjustments, the Company believes that the various revenue, expense, and rate base adjustments proposed by the opposing parties are not reasonable and therefore should be rejected. UGI Gas Exhibit A – Fully Projected (REBUTTAL) incorporates the concessions and modifications previously noted but otherwise reflects the rejection of the proposed adjustments by the other parties.

IV. OPERATING EXPENSE ADJUSTMENTS

A. RATE CASE EXPENSE

Q. Do any of the other parties propose adjustments to the Company's claimed rate case expense?

A. Yes. Both I&E Witness Walker and OCA Witness Rogers propose adjustments to the Company's claimed rate case expense.

Q. Please summarize I&E's and OCA's proposed adjustments.

A. I&E Witness Walker recommends that the Company's rate case expense be decreased by $880,000, based on the use of a 24-month normalization period. I&E St. No. 1, at pp. 9-15. He asserts that the Company's historic filing frequency should be based on an average of its most recent cases. I&E St. No. 1, at pp. 12. Witness Keller further cites to and relies upon recent Commission decisions, where the Commission has adopted I&E's reliance on historic filing frequency to normalize rate case expense. I&E St. No. 1, at pp. 12-15.

OCA Witness. Rogers also recommends that the Company's rate case expense be decreased by $880,000, based on the use of a 24-month normalization period. OCA St. 2, at p. 7; Schedule JLR-6.

Q. Does the Company agree with either I&E's or OCA's proposed adjustment to rate case expense?

A. No.

Q. Why is the 24-month normalization period advanced by I&E and OCA not reflective of the Company's rate case filing frequency?

A. The Company's expectation that it will file another base rate case in one year is based upon an assessment of future capital requirements, continued information system improvements, and the cost of other improvements as detailed in the Company's Third Long-Term Infrastructure Improvement Plan ("LTIIP") filing.[1] Many of these improvements are important replacement and betterment investments undertaken pursuant to legal commitments that will allow the system to function safely and reliably. The Company is implementing a continued accelerated replacement and betterment program as detailed in its Third LTIIP and this sustained capital investment supports a one-year rate case cycle and a one-year normalization of rate case expenses.

B. ENERGY EFFICIENCY AND CONSERVATION EXPENSE

[1] Petition of UGI Utilities, Inc. – Gas Division for Approval of its Third Long-Term Infrastructure Improvement Plan, Docket No. P-2024-3050769 (Opinion and Order entered Dec. 5, 2024).

Q. Did any party propose an adjustment to the Company's energy efficiency and conservation ("EE&C") plan expense?

A. Yes, OCA witness Walker proposed that the Company's EE&C expense be decreased.

Q. Please summarize OCA witness Walker's proposed adjustment.

A. Witness Walker states that the "Company's budgeted EE&C Plan expenses of $12,366,000 are recovered through gas distribution base rates, reconciled to match the amount of the current EE&C Rider charge at the time of the Company's filing" and recommends a $1,193,000 reduction to the EE&C expense based on a three-year historical average cost. I&E St. No. 1, at pp. 42-45.

Q. Do you agree with Witness Walker's adjustment?

A. No. The EE&C is not recovered through base rates. It is recovered through the fully reconcilable EE&C Rider. For the presentation of the EE&C plan in the FPFTY, expenses are set to fully offset the EE&C rider revenues. Therefore, no impact related to EE&C flows through the revenue requirement calculation. I&E's adjustment ignores the nature of this rider and treats the Company's EE&C costs as if they were an O&M expense not subject to a reconcilable rider. Additionally, Witness Walker's proposal is inconsistent with the treatment of other fully reconcilable riders presented in this case, including the USP and PGC, and is inconsistent with the PGC treatment recommended by Witness Cline in his testimony. I&E St. No. 3, at pp. 13-14. For these reasons, I&E Witness Walker's adjustment should be rejected. However, should the Commission agree with Witness

Walker's adjustment, a corresponding decrease in revenue must be made to acknowledge the fully reconcilable nature of the rider.

V. CASH WORKING CAPITAL

Q. Do any other parties address the Company's claim for CWC in this case?

A. Yes. I&E Witness Walker and OCA Witness Rogers both recommend adjustments to the Company's CWC claim, based upon the other expense adjustments proposed by I&E and OCA. I&E St. No. 1, at pp. 46-48 (recommending disallowance of $832,000 derived from other adjustments to the Company's expenses); OCA St. 2, at p. 6 (recommending disallowance of $3.76 million derived from other adjustments to the Company's expenses). Neither witness disputes the Company's lead/lag study or method for determining its CWC claim.

Q. Does the Company agree with either I&E's or OCA's CWC adjustments?

A. The Company agrees with the witnesses in principle – that to the extent its other claimed expenses are adjusted the CWC should be adjusted. However, the Company disagrees with the specific proposed adjustments to CWC, to the extent that the Company disagrees with the underlying expense or tax adjustments advanced by I&E and OCA.

Q. Please provide more detail on why the Company does not agree with the CWC adjustments proposed by I&E and OCA.

A. The Company disagrees with the CWC adjustments proposed by I&E and OCA, which are based upon a number of their proposed adjustments to O&M expenses. As explained in the rebuttal testimony of other Company witnesses, the Company disagrees with many of

these proposed adjustments but has also agreed to accept certain of them. In addition, the Company has updated various aspects of its O&M expense claims based upon information produced during discovery. For these reasons, the Company submits that its updated CWC claim of $66,348,000 that is reflected in Schedule A-1, UGI Gas Exhibit A – Fully Projected (REBUTTAL), which is a decrease of $175,000 from its as-filed claim, should be approved.

VI. INTEREST SYNCHRONIZATION ADJUSTMENT TO INCOME TAX EXPENSE

Q. What was the Company's original claim for income tax expense in this proceeding?

A. The Company's claim for income tax expense in this proceeding was $76,442,000 as reported on Schedule D-33 of UGI Gas Exhibit A (FPFTY). Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of Federal income taxes, and the flow through of accelerated depreciation benefits for state tax purposes. The Company's claimed interest expense deduction was $102,369,000 based on a rate base of $4,319,352,000 multiplied by the weighted cost of debt of 2.37% (45.75% x 5.17%) UGI Gas Exhibit A (FPFTY), Schedule B-7.

Q. Did any party challenge the Company's claim?

A. Yes. OCA Witness Rogers recommends a $909,000 decrease to state income taxes and a $2.4 million decrease to federal income taxes based upon OCA's recommended rate base and weighted cost of debt in its recommended capital structure. OCA St. 1, p. 16; Schedule JLR-16.

Q. Do you agree with OCA's proposed adjustment?

A. No. I note that UGI Gas witness Mr. D'Ascendis responds specifically to the OCA's proposed capital structure, cost of equity and overall rate of return in his rebuttal testimony (UGI Gas Statement No. 8-R). For the reasons fully identified in Mr. D'Ascendis's rebuttal testimony, OCA Witness Garrett's adjustments (in OCA St. 3) to the Company's actual capital structure and cost of equity should be rejected and so should Witness Rogers's adoption of that recommendation in OCA's revenue requirement model.

Q. Are there other adjustments made by the Company as part of its Rebuttal Case that impact the interest synchronization adjustment?

A. Yes. As discussed earlier, the Company has reflected an adjustment to the average cost of long-term debt, which increases the rate from 5.17% to 5.22%. This adjustment increases the interest deduction by $859,330 to $103,228,330 (based on a rate base of $4,319,177,000 multiplied by the weighted cost of debt of 2.39% (45.75% x 5.22%), UGI Gas Exhibit A – Fully Projected Future (REBUTTAL), Schedule B-7. The interest increase of $859,330, coupled with the decrease to revenue, decreases the federal income taxes by $2,000 and decreases the state income taxes by $1,000.

VII. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Rebuttal Exhibit A

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission

Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)
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C-3	Accumulated Provision for Depreciation	A. M. Keller
	Summary of Accumulated Depreciation	A. M. Keller
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	Negative Net Salvage Amortization	A. M. Keller
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C-4	Working Capital	A. M. Keller
	Summary of Working Capital	A. M. Keller
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	Summary of Expense Lag Calculations	A. M. Keller
	General Disbursements Payment Lag Summary	A. M. Keller
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	Interest Payments	A. M. Keller
	Tax Payment Lag Calculations	A. M. Keller
	Prepaid Expenses	A. M. Keller
C-5	Gas Inventory	A. M. Keller
C-6	Accumulated Deferred Income Taxes	D. T. Espigh
C-7	Customer Deposits	A. M. Keller
C-8	Materials & Supplies	A. M. Keller
C-9	SCHEDULE NOT USED	N/A

UGI Utilities, Inc. - Gas Division
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Fully Projected Future Period - 12 Months Ended September 30, 2027

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	SECTION D	
D-1	Summary of Revenue and Expenses Pro Forma with Proposed Revenue Increase	T. A. Hazenstab
D-2	Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase	T. A. Hazenstab
D-3	Summary of Pro Forma Adjustments	T. A. Hazenstab
D-4	SCHEDULE NOT USED	N/A
D-5	Adjustment - Revenue Adjustments	S. A. Epler
D-5A	Adjustment - Test Year Revenue Changes	S. A. Epler
D-5B	Adjustment - CIAC on Tax Gross-Ups	D. T. Espigh
D-6	Adjustment - Gas Costs	S. A. Epler
D-7	Adjustment - Salaries & Wages	T. A. Hazenstab
D-8	Adjustment - Environmental	A. M. Keller
D-9	SCHEDULE NOT USED	N/A
D-10	Adjustment - Rate Case Expense	T. A. Hazenstab
D-11	Adjustment - Uncollectibles	V. K. Ressler
D-12	SCHEDULE NOT USED	N/A
D-13	SCHEDULE NOT USED	N/A
D-14	Adjustment - Benefits Adjustments	A. M. Keller
D-15	Adjustment - Other Adjustments	V. K. Ressler
D-16	Adjustment - Universal Service	S. A. Epler
D-17	SCHEDULE NOT USED	N/A
D-18	SCHEDULE NOT USED	N/A
D-19	Adjustment - Energy Efficiency and Conservation Programs	S. A. Epler
D-21	Adjustment - Depreciation expense	J.F. Weidmayer
D-31	Adjustment - Taxes Other Than Income Taxes	T. A. Hazenstab
D-32	Adjustment - Payroll Taxes	T. A. Hazenstab
D-33	Income Tax Calculation	D. T. Espigh
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D-35	Gross Revenue Conversion Factor	T. A. Hazenstab

UGI Utilities, Inc. - Gas Division | **Schedule A-1**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2027 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 6,676,559		$ 6,676,559
2	Accumulated Depreciation		C-3	(1,736,046)		(1,736,046)
3	Net Plant in service	L 1 + L 2		4,940,513	-	4,940,513
4	Working Capital		C-4	66,348		66,348
5	Gas Inventory		C-5	23,662		23,662
6	Accumulated Deferred Income Taxes		C-6	(716,793)		(716,793)
7	Customer Deposits		C-7	(23,197)		(23,197)
8	Materials & Supplies		C-8	28,644		28,644
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 4,319,177	$ -	$ 4,319,177
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 816,121	$ 98,693	$ 914,814
11	Gas Cost Revenue		D-5	405,467		405,467
12	Other Operating Revenues		D-5	14,131		14,131
13	Total Revenues	Sum L 10 to L 12		1,235,719	98,693	1,334,412
14	Operating Expenses		D-1	(901,236)	(1,700)	(902,937)
15	OIBIT	L 13 + L 14		334,483	96,993	431,476
16	Pro Forma Income Tax at Present Rates		D-33	(50,332)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(26,108)	(76,439)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 284,151	$ 70,885	$ 355,036
19	RATE OF RETURN	L 18 / L 9		6.5788%		8.2200%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		6.5788%		
21	Rate of Return Required		B-7	8.2200%		
22	Change in ROR	L 21 - L 20		1.6412%		
23	Change in Operating Income	L 22 * L 9		$ 70,885		
24	Gross Revenue Conversion Factor		D-35	1.392298		
25	Change in Revenues	L 23 * L 24		$ 98,693		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, Col 3			12.09%	
27	Percent Increase -- Total Revenues	L 25 / L 13, Col 3			7.99%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-1
Witness: A. M. Keller
Page 1 of 2

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-27
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 6,218,576
2	Other Utility Plant	
3	Total Plant In Service	6,218,576
4	Construction Work In Progress (107)	123,341
5	Total Utility Plant	6,341,917
6	Accumulated Provision for Depreciation - Gas (108)	(1,618,836)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	
9	Net Utility Plant	4,905,226
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	714
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,168
13	Other Investments (124)	15
14	Total Other Property and Investments	1,897
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	15,093
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	108,551
18	Other Accounts Receivable (143)	13,706
19	Accum Provision for Uncollectible (144)	(14,810)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	3,596
22	Plant Materials & Operating Supplies (154)	23,722
23	Stores Expense - Undistributed (163)	2,470
24	Gas Stored - Current (164.1)	53,036
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	20,395
27	Accrued Utility Revenues (173)	24,907
28	Miscellaneous Current & Accrued Assets (174)	148
29	Derivative Instrument Assets (175)	2,244
30	Total Current and Accrued Assets	253,058
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	7,882
32	Other Regulatory Assets (182.3)	484,191
33	Other Preliminary Survey & Investigation Charges (183.2)	48
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	26,845
36	Def. Losses from Disposition of Utility Plt. (187)	-
37	Unamortized Loss on Reacquired Debt (189)	-
38	Accumulated Deferred Income Taxes (190)	-
39	O/U Collected Gas (191.4, 191.41)	-
40	Total Deferred Debits	518,966
41	TOTAL ASSETS AND OTHER DEBITS	$ 5,679,146

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-1
Witness: A. M. Keller
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Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-27
	PROPRIETARY CAPITAL	
42	Common Stock Issued (201)	$ 53,926
43	Preferred Stock Issued (204)	-
44	Premium on Capital Stock (207)	559,361
45	Capital Stock Expense (214)	-
46	Retained Earnings (215, 215.2, 216)	1,332,939
47	Accum Other Comprehensive Income (219)	(12,094)
48	Total Proprietary Capital	1,934,133
	LONG TERM DEBT	
49	Bonds (221)	-
50	Advances from Associated Companies (223)	-
51	Other Long-Term Debt (224)	2,040,706
52	Unamortized Premium on LTD (225)	-
53	Unamortized Discount on LTD (226)	-
54	Total Long-term Debt	2,040,706
	OTHER NON-CURRENT LIABILITIES	
55	Obligations under Capital Leases (227)	163
56	Accum. Prov for Injuries & Damages (228.2)	1,890
57	Accum. Prov for Pensions & Benefits (228.3)	0
58	Accum. Miscellaneous Operating Prov (228.4)	52,272
59	Asset Retirement Obligation (230)	111
60	Total Non-Current Liabilities	54,437
	CURRENT & ACCRUED LIABILITIES	
61	Notes Payable (231)	254,520
62	Accounts Payable (232)	97,314
63	Notes Payable to Assoc. Companies (233)	-
64	Accounts Payable to Assoc. Cos (234)	2,285
65	Customer Deposits (235)	23,852
66	Taxes Accrued (236)	(10,612)
67	Interest Accrued (237)	23,710
68	Tax Collections Payable (241)	755
69	Misc Current & Accrued Liabilities (242)	83,538
70	Obligations Under Capital Leases (243)	504
71	Derivative Instrument Liabilities (244)	6,278
72	Total Current & Accrued Liabilities	482,145
	OTHER DEFERRED CREDITS	
73	Customer Advances for Construction (252)	-
74	Other Deferred Credits (253)	22,505
75	Other Regulatory Liabilities (254)	270,522
76	Deferred ITC (255)	791
77	Accumulated Deferred Income Taxes (282)	821,359
78	Accumulated Deferred Income Taxes (283)	52,548
79	Total Other Deferred Credits	1,167,725
80	TOTAL LIABILITIES & OTHER CREDITS	$ 5,679,146

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule B-2
Witness: T. A. Hazenstab
Page 1 of 1

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-27	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 1,270,313	B-3
2	Other Operating Revenues	13,419	B-3
3	Total Revenues	1,283,732	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	733,496	B-4
5	Depreciation & Amortization Expense	164,574	D-2
6	Taxes Other Than Income Taxes	14,211	B-5
7	Total Operating Expenses	912,281	
8	Operating Income Before Income Taxes (OIBIT)	371,450	
	Income Taxes:		
9	State	8,948	B-5
10	Federal	41,383	B-5
11	Total Income Taxes	50,332	
12	**Net Utility Operating Income**	$ 321,119	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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Schedule B-3
Witness: T. A. Hazenstab
Page 1 of 1

Statement of Operating Revenues

Line No	Description	[1] Budget TYE 9-30-27
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 815,696
2	Comm & Ind (N/NT) (481)	295,972
3	Comm & Ind (DS) (489)	36,322
4	Lg Transport/Other (489)	99,453
5	Interruptible (489)	22,870
6	Sub-Total Gas Operating Revenues	1,270,313
	Other Operating Revenues	
7	Forfeited Discounts (487)	6,337
8	Miscellaneous Service Revenues (488)	3,178
9	Rent from Gas Properties (493)	2,292
10	Other Revenues (495)	1,612
11	Sub-Total Other Operating Revenues	13,419
12	**Total Operating Revenues**	$ 1,283,732

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab
Page 1 of 3

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	-
3	Total Gas Raw Materials Expenses		-
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	530,074
16	Other Gas Purchases	805.0	5
17	Purchases Gas Cost Adjustments	805.1	(81,826)
18	Gas Withdrawn from Storage-Debit	808.1	47,230
19	Purchased Gas Expenses	807.0	-
20	Gas Used for Other Utility Operations-Credit	812.0	2,169
21	Gas Delivered to Storage-Credit	808.2	(62,675)
22	Other Gas Supply Expenses	813.0	(5,256)
23	Gas Supply Operation Expenses		429,721
	Underground Storage Expense - Operation		
24	Operation Supervision and Engineering	814	-
25	Maps and Records	815	-
26	Wells Expenses	816	-
27	Lines Expenses	817	-
28	Measuring and Regulating Station Expenses	820	-
29	Purification Expenses	821	-
30	Gas Losses	823	-
31	Other Expenses	824	-
32	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
33	Maintenance Supervision and Engineering	830	-
34	Maintenance of Structures and Improvements	831	-
35	Maintenance of Reservoirs and Wells	832	-
36	Maintenance of Lines	833	-
37	Maintenance of Measuring & Regulating Station Equip.	835	-
38	Total Underground Maintenance Expenses		-

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab
Page 2 of 3

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Transmission Expense - Operations		
39	Operating Supervision and Engineering	850	-
40	System Control and Load Dispatching	851	-
41	Communication System Expenses	852	-
42	Mains Expenses	856	-
43	Measuring and Regulating Station Expenses	857	-
44	Other Expenses	859	-
45	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
46	Maintenance Supervision and Engineering	861	-
47	Maintenance of Structures and Improvements	862	-
48	Maintenance of Mains	863	-
49	Maintenance of Measuring and Regulating Station Equip.	865	-
50	Maintenance of Communication Equipment	866	-
51	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
52	Operation Supervision and Engineering	870	6,264
53	Distribution Load Dispatching	871	3,424
54	Compressor Station Fuel and Power (Major Only)	873	-
55	Mains and Services Expenses	874	34,590
56	Measuring and Regulating Station Expenses-General	875	2,194
57	Measuring and Regulating Station Expenses-Industrial	876	21
58	Measuring and Regulating Station Expenses-City Gate	877	456
59	Meter and House Regulator Expenses	878	3,661
60	Customer Installations Expenses	879	3,328
61	Other Expenses	880	7,219
62	Rents	881	651
63	Total Distribution Operation Expenses		61,808
	Distribution Expense - Maintenance		
64	Maintenance Supervision and Engineering	885	2,325
65	Maintenance of Structures and Improvements	886	-
66	Maintenance of Mains	887	21,659
67	Maintenance of Compressor Station Equipment	888	-
68	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	2,353
69	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	3,991
70	Maintenance of Measuring & Reg. Station Equip.-City G	891	105
71	Maintenance of Services	892	677
72	Maintenance of Meters & House Regulators	893	40
73	Maintenance of Other Equipment	894	592
74	Construction & Maintenance	895	-
75	Total Distribution Maintenance Expenses		31,741
	Customer Accounts Expense - Operations		
76	Supervision	901	873
77	Meter Reading Expenses	902	2,940
78	Customer Records & Collection Expenses	903	58,278
79	Uncollectable Accounts	904	20,671
80	Miscellaneous Customer Accounts Expenses	905	70
81	Total Administrative & General		82,832

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab
Page 3 of 3

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-27
	Customer Service & Information Expense		
82	Supervision	907	89
83	Customer Assistance Expenses	908	1,099
84	Informational & Instructional Advertising Expenses	909	1,358
85	Miscellaneous Customer Service & Informational Exp.	910	12,447
86	Total Cust. Service & Inform. Operations Exp		14,993
	Sales Expense		
87	Supervision	911	-
88	Demonstrating and Selling Expenses	912	758
89	Advertising Expenses	913	526
90	Miscellaneous Sales Expenses	916	-
91	Total Operation Sales Expenses		1,283
	Administrative & General - Operations		
92	Administrative and General Salaries	920.0	35,181
93	Office Supplies and Expenses	921.0	19,009
94	Outside Service Employed	923.0	20,445
95	Property Insurance	924.0	361
96	Injuries and Damages	925.0	11,158
97	Employee Pensions and Benefits	926.0	15,577
98	Regulatory Commission Expenses	928.0	2,296
99	General Advertising Expenses	930.1	171
100	Miscellaneous General Expenses	930.2	1,616
101	Rents	931.0	77
102	Total A & G Operation Expenses		105,891
	Administrative & General - Maintenance		
103	A&G Maintenance of General Plant	932	5,228
104	A&G Maintenance of General Plant	935	-
105	Total A & G Maintenance Expenses		5,228
106	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 733,496
107	Total Gas Operation Expenses		696,528
108	Total Gas Maintenance Expense		36,969
109	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 733,496

UGI Utilities, Inc. - Gas Division | **Schedule B-5**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-27
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 1,420
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	1,250
4	PUC Assessment	D-31	5,131
5	Subtotal		7,801
	Payroll Taxes		
6	FICA	D-31	6,087
7	SUTA	D-31	317
8	FUTA	D-31	6
9	Other		-
10	Subtotal		6,410
11	Total Taxes Other Than Income Taxes		$ 14,211
	Income Taxes		
12	State		$ 8,948
13	Federal		41,383
14	Total Income Taxes		$ 50,332

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule B-6
Witness: D. W. D'Ascendis
Page 1 of 1

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4]*[5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	0.94%	6.56%	0.06%
2	6.133%	10/14/2004	10/15/2034	20,000	0.94%	6.19%	0.06%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	4.70%	6.32%	0.30%
4	4.980%	3/26/2014	3/26/2044	175,000	8.22%	5.00%	0.41%
5	4.120%	9/30/2016	9/30/2046	200,000	9.39%	5.01%	0.47%
6	4.120%	10/31/2016	10/31/2046	100,000	4.70%	4.28%	0.20%
7	4.550%	2/1/2019	2/1/2049	150,000	7.05%	4.58%	0.32%
8	3.120%	3/19/2020	4/16/2050	150,000	7.05%	3.15%	0.22%
9	4.750%	7/15/2022	7/15/2032	90,000	4.23%	4.82%	0.20%
10	4.990%	9/15/2022	9/15/2052	85,000	3.99%	5.03%	0.20%
11	6.100%	11/30/2023	11/30/2033	150,000	7.05%	6.17%	0.43%
12	6.400%	11/30/2023	11/30/2053	75,000	3.52%	6.43%	0.23%
13	6.020%	11/30/2023	11/30/2030	25,000	1.17%	6.11%	0.07%
14	5.240%	11/14/2024	11/30/2029	50,000	2.35%	5.38%	0.13%
15	5.520%	11/14/2024	11/30/2034	125,000	5.87%	5.60%	0.33%
16	5.100%	11/14/2025	11/14/2035	150,000	7.05%	5.16%	0.36%
17	5.680%	11/14/2025	11/14/2035	125,000	5.87%	5.75%	0.34%
18	5.600%	1/31/2026	6/30/2036	75,000	3.52%	5.67%	0.20%
19	5.693%	11/30/2026	11/30/2036	200,000	9.39%	5.78%	0.54%
Term Loan							
20	4.900%	1/31/2027	1/31/2032	64,063	3.01%	5.05%	0.15%
21	Total Long-Term Debt			$ 2,129,063	100.00%		5.22%
22	Total Long-Term Debt			$ 2,129,063	100.00%	5.22%	5.22%
23	Total Short-Term Debt				0.00%		0.00%
24	TOTAL			$ 2,129,063	100.00%		
25	Weighted Cost of Debt						5.22%
26	As-Filed Weighted Cost of Debt						5.17%

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule B-7
Witness: D. W. D'Ascendis
Page 1 of 1

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	45.75%	5.22%	B-6	2.39%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	54.25%	10.75%		5.83%
4	Total	100.00%			8.22%
5	As Filed Rate of Return				8.20%

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-1
Witness: A. M. Keller
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Measure of Value

Line #	Description	[1] Reference Schedule	[2] # of Pages	[3] Pro Forma Test Year Ended September 30, 2027 At Present Rates	[4] Adjustments	[5] Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 6,676,559		$ 6,676,559
2	Accumulated Depreciation	C-3	11	(1,736,046)		(1,736,046)
3	Net Plant in service			4,940,513	-	4,940,513
4	Working Capital	C-4	9	66,348		66,348
5	Gas Inventory	C-5	1	23,662		23,662
6	Accumulated Deferred Income Taxes	C-6	1	(716,793)		(716,793)
7	Customer Deposits	C-7	1	(23,197)		(23,197)
8	Materials & Supplies	C-8	1	28,644		28,644
9	TOTAL MEASURE OF VALUE			$ 4,319,177	$ -	$ 4,319,177

UGI Utilities, Inc. - Gas Division
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Schedule C-2
Witness: A. M. Keller
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Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule C-2
Witness: A. M. Keller
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Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,468
34	Measuring & Regulating Station Equipment	369	6,173
35	Communication Equipment	370	3,505
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,575
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,638
39	Structures & Improvements	375	7,923
40	Mains	376	3,190,354
41	Measuring & Regulating Station Equipment	378	229,058
42	Measuring & Regulating Station Equipment	379	81,780
43	Services	380	1,937,404
44	Meters	381	219,403
45	Meter Installations	382	153,632
46	House Regulators	383	10,274
47	House Regulatory Installations	384	17,829
48	Industrial Measuring & Reg. Station Equipment	385	42,671
49	Other Property	386	1,274
50	Other Equipment	387	6,799
51	TOTAL DISTRIBUTION		5,910,038
	GENERAL PLANT		
52	Land & Land Rights	389	14,128
53	Structures & Improvements	390	240,055
54	Office Furniture & Equipment	391	308,260
55	Transportation Equipment	392	87,535
56	Stores Equipment	393	16
57	Tools & Garage Equipment	394	46,259
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	13,798
60	Communication Equipment	397	2,364
61	Miscellaneous Equipment	398	2,320
62	Other Tangible Property	399	-
63	TOTAL GENERAL		715,173
64	Total Plant		$ 6,676,559

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-2
Witness: A. M. Keller
Page 3 of 9

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/27 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	-	-	-
4	Transmission Plant	Sch C-2, Page 5	50,575	-	50,575
5	Distribution Plant	Sch C-2, Page 5	5,910,038	-	5,910,038
6	General Plant	Sch C-2, Page 5	715,173	-	715,173
7	Other Plant		-	-	-
8	Total Utility Plant		$ 6,676,559	$ -	$ 6,676,559

UGI Utilities, Inc. - Gas Division
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Schedule C-2
Witness: A. M. Keller
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Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ 290	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	194	-	194
3	Miscellaneous Intangible Plant	303	290	290	-	290
4	TOTAL INTANGIBLE		774	774	-	774
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	-	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-	-

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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Schedule C-2
Witness: A. M. Keller
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Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	47	47	-	47
31	Rights of Way	365.2	868	868	-	868
32	Structures & Improvements	366	162	162	-	162
33	Mains	367	39,468	39,468	-	39,468
34	Measuring & Regulating Station Equipment	369	6,173	6,173	-	6,173
35	Communication Equipment	370	3,505	3,505	-	3,505
36	Other Equipment	371	351	351	-	351
37	TOTAL TRANSMISSION		50,575	50,575	-	50,575
DISTRIBUTION PLANT						
38	Land & Land Rights	374	11,638	11,638	-	11,638
39	Structures & Improvements	375	7,923	7,923	-	7,923
40	Mains	376	2,956,090	3,190,354	-	3,190,354
41	Measuring & Regulating Station Equipment	378	191,451	229,058	-	229,058
42	Measuring & Regulating Station Equipment	379	81,780	81,780	-	81,780
43	Services	380	1,799,933	1,937,404	-	1,937,404
44	Meters	381	205,771	219,403	-	219,403
45	Meter Installations	382	147,331	153,632	-	153,632
46	House Regulators	383	10,274	10,274	-	10,274
47	House Regulatory Installations	384	17,829	17,829	-	17,829
48	Industrial Measuring & Reg. Station Equipment	385	41,443	42,671	-	42,671
49	Other Property	386	1,274	1,274	-	1,274
50	Other Equipment	387	6,799	6,799	-	6,799
51	TOTAL DISTRIBUTION		5,479,536	5,910,038	-	5,910,038
GENERAL PLANT						
52	Land & Land Rights	389	14,128	14,128	-	14,128
53	Structures & Improvements	390	224,104	240,055	-	240,055
54	Office Furniture & Equipment	391	298,038	308,260	-	308,260
55	Transportation Equipment	392	77,031	87,535	-	87,535
56	Stores Equipment	393	16	16	-	16
57	Tools & Garage Equipment	394	45,411	46,259	-	46,259
58	Laboratory Equipment	395	438	438	-	438
59	Power Operated Equipment	396	13,798	13,798	-	13,798
60	Communication Equipment	397	3,095	2,364	-	2,364
61	Miscellaneous Equipment	398	1,937	2,320	-	2,320
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		677,996	715,173	-	715,173
64	Total Plant		$ 6,208,881	$ 6,676,559	$ -	$ 6,676,559

UGI Utilities, Inc. - Gas Division | **Schedule C-2**
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Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 6 of 9**
($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2026	[3] Year ended September 30, 2027
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

UGI Utilities, Inc. - Gas Division | **Schedule C-2**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 7 of 9**
($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2026	[3] Year ended September 30, 2027
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	759	-
40	Mains	376	210,564	241,883
41	Measuring & Regulating Station Equipment	378	27,444	37,902
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	134,149	159,733
44	Meters	381	15,547	16,346
45	Meter Installations	382	6,296	7,321
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	1,002	1,237
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		395,762	464,422
	GENERAL PLANT			
52	Land & Land Rights	389	606	-
53	Structures & Improvements	390	16,683	16,746
54	Office Furniture & Equipment	391	43,926	12,273
55	Transportation Equipment	392	11,248	11,672
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	1,834	2,374
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	524	507
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		74,820	43,572
64	Total Plant		$ 470,582	$ 507,994

UGI Utilities, Inc. - Gas Division | **Schedule C-2**
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Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 8 of 9**
($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

UGI Utilities, Inc. - Gas Division | **Schedule C-2**
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($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	-	
39	Structures & Improvements	375	(17)	
40	Mains	376	(6,651)	(7,619)
41	Measuring & Regulating Station Equipment	378	(214)	(295)
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	(18,697)	(22,263)
44	Meters	381	(2,615)	(2,714)
45	Meter Installations	382	(878)	(1,020)
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	(8)	(10)
49	Other Property	386	-	
50	Other Equipment	387	-	
51	TOTAL DISTRIBUTION		(29,079)	(33,921)
	GENERAL PLANT			
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	(345)	(795)
54	Office Furniture & Equipment	391	(27,513)	(2,051)
55	Transportation Equipment	392	(1,125)	(1,167)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	(1,231)	(1,526)
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	(731)
61	Miscellaneous Equipment	398	(97)	(124)
62	Other Tangible Property	399	(16)	-
63	TOTAL GENERAL		(30,327)	(6,395)
64	Total Plant		$ (59,406)	$ (40,316)

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-3
Witness: A. M. Keller
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Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	-
7	Rights of Way	325	-
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 2 of 11**
($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma TYE 9-30-27
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	594
32	Structures & Improvements	366	157
33	Mains	367	23,932
34	Measuring & Regulating Station Equipment	369	4,437
35	Communication Equipment	370	2,631
36	Other Equipment	371	312
37	TOTAL TRANSMISSION		32,063
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,594
39	Structures & Improvements	375	3,846
40	Mains	376	644,412
41	Measuring & Regulating Station Equipment	378	51,380
42	Measuring & Regulating Station Equipment	379	18,454
43	Services	380	508,598
44	Meters	381	91,740
45	Meter Installations	382	52,438
46	House Regulators	383	6,278
47	House Regulatory Installations	384	10,128
48	Industrial Measuring & Reg. Station Equipment	385	22,284
49	Other Property	386	729
50	Other Equipment	387	4,894
51	TOTAL DISTRIBUTION		1,416,775
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	70,116
54	Office Furniture & Equipment	391	149,964
55	Transportation Equipment	392	39,498
56	Stores Equipment	393	9
57	Tools & Garage Equipment	394	18,442
58	Laboratory Equipment	395	223
59	Power Operated Equipment	396	6,980
60	Communication Equipment	397	752
61	Miscellaneous Equipment	398	1,223
62	Other Tangible Property	399	
63	TOTAL GENERAL		287,208
64	Total Plant		$ 1,736,046

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-3
Witness: A. M. Keller
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Summary of Accumulated Depreciation

Line #	Description	[1] Factor Or Reference	[2] Test Year Ended September 30, 2027 Amount	[3] Pro Forma Adjustment	[4] Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	$ -	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	-	-	-
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	-	-	-
4	Transmission Plant	Sch C-3, Pg 5	32,063	-	32,063
5	Distribution Plant	Sch C-3, Pg 5	1,416,775	-	1,416,775
6	General Plant	Sch C-3, Pg 5	287,208	-	287,208
7	Other Plant		-	-	-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,736,046	$ -	$ 1,736,046

UGI Utilities, Inc. - Gas Division
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Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ -	$ -	-	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	-	-	-	-
7	Rights of Way	325.4	-	-	-	-
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-	-
10	Other Structures	329	-	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-	-
13	Field Lines	332	-	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-	-
16	Other Equipment	337	-	-	-	-
17	TOTAL PRODUCTION & GATHERING		-	-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		-	-	-	-

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

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Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027	[4] Pro Forma Adjustment	[5] Balance
TRANSMISSION PLANT						
30	Land & Land Rights	365.1	-	-	-	-
31	Rights of Way	365.2	583	594	-	594
32	Structures & Improvements	366	157	157	-	157
33	Mains	367	23,526	23,932	-	23,932
34	Measuring & Regulating Station Equipment	369	4,348	4,437	-	4,437
35	Communication Equipment	370	2,549	2,631	-	2,631
36	Other Equipment	371	306	312	-	312
37	TOTAL TRANSMISSION		31,470	32,063	-	32,063
DISTRIBUTION PLANT						
38	Land & Land Rights	374	1,551	1,594	-	1,594
39	Structures & Improvements	375	3,694	3,846	-	3,846
40	Mains	376	603,006	644,412	-	644,412
41	Measuring & Regulating Station Equipment	378	46,205	51,380	-	51,380
42	Measuring & Regulating Station Equipment	379	16,033	18,454	-	18,454
43	Services	380	485,016	508,598	-	508,598
44	Meters	381	86,841	91,740	-	91,740
45	Meter Installations	382	50,079	52,438	-	52,438
46	House Regulators	383	5,133	6,278	-	6,278
47	House Regulatory Installations	384	9,801	10,128	-	10,128
48	Industrial Measuring & Reg. Station Equipment	385	21,131	22,284	-	22,284
49	Other Property	386	701	729	-	729
50	Other Equipment	387	4,802	4,894	-	4,894
51	TOTAL DISTRIBUTION		1,333,994	1,416,775	-	1,416,775
GENERAL PLANT						
52	Land & Land Rights	389	-	-	-	-
53	Structures & Improvements	390	62,353	70,116	-	70,116
54	Office Furniture & Equipment	391	125,461	149,964	-	149,964
55	Transportation Equipment	392	33,930	39,498	-	39,498
56	Stores Equipment	393	8	9	-	9
57	Tools & Garage Equipment	394	17,652	18,442	-	18,442
58	Laboratory Equipment	395	201	223	-	223
59	Power Operated Equipment	396	6,099	6,980	-	6,980
60	Communication Equipment	397	1,216	752	-	752
61	Miscellaneous Equipment	398	1,208	1,223	-	1,223
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		248,128	287,208	-	287,208
64	Total Plant		$ 1,613,591	$ 1,736,046	$ -	$ 1,736,046

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330		
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305		
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	7	-
40	Mains	376	1,939	2,218
41	Measuring & Regulating Station Equipment	378	53	74
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	7,271	8,658
44	Meters	381	-	-
45	Meter Installations	382	341	397
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	(326)	(403)
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		9,287	10,944
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	31	72
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	-	-
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		31	72
64	Total Plant		$ 9,318	$ 11,016

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 9 of 11**
($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	3	3
34	Measuring & Regulating Station Equipment	369	1	0
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		4	3
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	4	4
40	Mains	376	2,586	2,600
41	Measuring & Regulating Station Equipment	378	203	162
42	Measuring & Regulating Station Equipment	379	85	65
43	Services	380	5,360	6,182
44	Meters	381	38	38
45	Meter Installations	382	157	203
46	House Regulators	383	872	872
47	House Regulatory Installations	384	1	1
48	Industrial Measuring & Reg. Station Equipment	385	(48)	(128)
49	Other Property	386	0	0
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		9,259	9,999
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	138	152
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(789)	(502)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	4	0
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	3	3
61	Miscellaneous Equipment	398	78	48
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(566)	(300)
64	Total Plant		$ 8,698	$ 9,703

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 10 of 11**
($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

UGI Utilities, Inc. - Gas Division | **Schedule C-3**
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Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 11 of 11**
($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2026	[3] Year Ended September 30, 2027
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	-	-
41	Measuring & Regulating Station Equipment	378	-	-
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	-	-
44	Meters	381	-	-
45	Meter Installations	382	-	-
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		-	-
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	-
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(112)	(117)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(112)	(117)
64	Total Plant		$ (112)	$ (117)

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-4
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Working Capital

Line No	Description	[1] Fully Projected TYE 9-30-27	[2] Reference
1	Working Capital for O & M Expense	$ 56,928	C-4, Page 2
2	Interest Payments	(9,550)	C-4, Page 7
3	Tax Payment Lag Calculations	4,570	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 66,348	

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-4
Witness: A. M. Keller
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Summary of Working Capital

Line #	Description	Reference	[1] Test Year Expenses	[2] Factor	[3] Number of (Lead) / Lag Days [2] * [3]	[4] Totals
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				57.46
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 81,356	12.00	$ 976,269	
4	Purchased Gas Costs	Sch D-6	405,467	26.09	10,576,851	
5	Other Expenses	L 18 - L 3 to L 4	208,376	36.55	7,616,146	
6	Total	Sum (L 3 to L 5)	$ 695,199		$ 19,169,266	
7	O & M Expense Lag Days	L6, C 4 / C 2				27.57
8	Net (Lead) Lag Days	L 1 - L 7				29.88
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,905
10	Working Capital for O & M Expense	L 8 * L 9				$ 56,928
11	Interest Payments	Page 7				(9,550)
12	Tax Payment Lag Calculations	Page 8				4,570
13	Prepaid Expenses	Page 9				14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 66,348
15	Pro Forma O & M Expense		$ 715,558			
	Less:					
16	Uncollectible Expense		20,359			
17	Sub-Total		20,359			
18	Pro Forma Cash O&M Expense		$ 695,199			

UGI Utilities, Inc. - Gas Division
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Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]	[5] Days Lag 365 / [4]
1	Annual Number of Days					365
2	September, 2024		$59,595			
3	October		$54,962	$49,570		
4	November		$65,027	$66,062		
5	December, 2024		$115,180	$130,278		
6	January, 2025		$180,732	$200,306		
7	February		$209,136	$183,549		
8	March		$200,671	$160,286		
9	April		$178,319	$106,926		
10	May		$148,644	$67,400		
11	June		$131,419	$49,633		
12	July		$110,237	$42,524		
13	August		$88,906	$37,847		
14	September, 2025		$72,798	$41,343		
15	Total	Sum L 2 to L 14	$1,615,626			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$124,279			
18	Total Sales for Year	Sum L 2 to L 14		$ 1,135,724		
19	Acct Rec Turnover Ratio	L 18 / L 17			9.14	
20	Collection Lag Day Factor	L 1 / L 19				39.93
21	Meter Read Lag Factor					2.32
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**57.46**

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-4
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Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 36,103	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	46,417	12.00		
3	Weighted for Union	L1, C2 * C3			$ 433,236	
4	Weighted for Other	L2, C2 * C3			557,008	
5	Payroll Lag	L 3 + L 4	$ 82,520		$ 990,244	
6	Payroll Lag Days	L5, C4 / C2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 505,975		$ 13,198,681	
8	Gas Cost Lag Days	L7, C4 / C2				26.09
OTHER O & M EXPENSES						
9	October-2024	Page 5	$ 12,404		$ 323,056	
10	November-2024	Page 5	9,141		250,782	
11	December-2024	Page 5	10,855		287,049	
12	January-2025	Page 5	25,282		1,499,042	
13	February-2025	Page 5	15,794		514,617	
14	March-2025	Page 5	9,353		273,241	
15	April-2025	Page 5	12,385		289,995	
16	May-2025	Page 5	13,770		597,078	
17	June-2025	Page 5	14,096		499,028	
18	July-2025	Page 5	20,034		1,249,027	
19	August-2025	Page 5	13,203		391,825	
20	September-2025	Page 5	38,365		941,232	
21	TOTAL		$ 194,681		$ 7,115,972	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				36.55

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($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
October-2024					
1	Total Disbursements for Month	32,838	$ 62,746		
2	Total Disbursements for Expenses	3,838	$ 12,404	$ 323,056	26.04
November-2024					
3	Total Disbursements for Month	23,901	$ 38,794		
4	Total Disbursements for Expenses	3,565	$ 9,141	$ 250,782	27.43
December-2024					
5	Total Disbursements for Month	24,687	$ 38,022		
6	Total Disbursements for Expenses	4,006	$ 10,855	$ 287,049	26.44
January-2025					
7	Total Disbursements for Month	21,368	$ 50,983		
8	Total Disbursements for Expenses	3,947	$ 25,282	$ 1,499,042	59.29
February-2025					
9	Total Disbursements for Month	18,066	$ 32,989		
10	Total Disbursements for Expenses	3,439	$ 15,794	$ 514,617	32.58
March-2025					
11	Total Disbursements for Month	18,513	$ 27,337		
12	Total Disbursements for Expenses	3,735	$ 9,353	$ 273,241	29.21
April-2025					
13	Total Disbursements for Month	25,630	$ 41,058		
14	Total Disbursements for Expenses	4,257	$ 12,385	$ 289,995	23.41
May-2025					
15	Total Disbursements for Month	34,781	$ 47,440		
16	Total Disbursements for Expenses	4,049	$ 13,770	$ 597,078	43.36
June-2025					
17	Total Disbursements for Month	29,782	$ 46,699		
18	Total Disbursements for Expenses	4,127	$ 14,096	$ 499,028	35.40
July-2025					
19	Total Disbursements for Month	31,463	$ 57,790		
20	Total Disbursements for Expenses	4,523	$ 20,034	$ 1,249,027	62.35
August-2025					
21	Total Disbursements for Month	32,254	$ 46,003		
22	Total Disbursements for Expenses	4,224	$ 13,203	$ 391,825	29.68
September-2025					
23	Total Disbursements for Month	34,037	$ 80,893		
24	Total Disbursements for Expenses	3,958	$ 38,365	$ 941,232	24.53
25	Total Test Month Expense Disbursement	47,668	$ 194,681	$ 7,115,972	36.55

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027

Schedule C-4
Witness: A. M. Keller
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Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October-2024	37	$ 38,708	$ 521,883	13.48
2	November-2024	38	42,900	573,631	13.37
3	December-2024	42	61,187	1,434,065	23.44
4	January-2025	45	101,888	1,975,569	19.39
5	February-2025	42	73,452	1,791,212	24.39
6	March-2025	33	37,168	1,424,885	38.34
7	April-2025	35	39,413	1,421,523	36.07
8	May-2025	31	26,967	1,017,164	37.72
9	June-2025	32	22,772	833,747	36.61
10	July-2025	28	22,723	835,609	36.77
11	August-2025	27	20,780	750,436	36.11
12	September-2025	30	18,017	618,957	34.35
13	Total		$ 505,975	$ 13,198,681	
14	Purchase Gas Lag Days				26.09

UGI Utilities, Inc. - Gas Division | **Schedule C-4**
Before the Pennsylvania Public Utility Commission | **Witness: A. M. Keller**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 7 of 9**

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2027	Sch C-1			$ 4,319,177
2	Long-term Debt Ratio	Sch B-7			45.75%
3	Embedded Cost of Long-term Debt	Sch B-6			5.22%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 103,148
5	Daily Amount	L 4 / L 5 [2]	365		$ 283
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		57.46	
8	Interest Payment lag days	L 7 - L 6			(33.8)
9	Total Interest for Working Capital	L 5 * L 8			$ (9,550)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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Schedule C-4
Witness: A. M. Keller
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Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount
											365
1	**FEDERAL INCOME TAX**				$ 60,226						
2	First Payment	01/15/27	04/01/27	76.00	$ 15,056	1,144,290					
3	Second Payment	03/15/27	04/01/27	17.00	15,056	255,960					
4	Third Payment	06/15/27	04/01/27	(75.00)	15,056	(1,129,233)					
5	Fourth Payment	09/15/27	04/01/27	(167.00)	15,056	(2,514,426)					
6	Total				$ 60,226	$ (2,243,410)	(37.25)	(57.46)	20.21	$ 1,216,982	$ 3,334
7	**STATE INCOME TAX**				$ 16,213						
8	First Payment	12/15/26	04/01/27	107.00	$ 4,053	433,700					
9	Second Payment	03/15/27	04/01/27	17.00	4,053	68,906					
10	Third Payment	06/15/27	04/01/27	(75.00)	4,053	(303,995)					
11	Fourth Payment	09/15/27	04/01/27	(167.00)	4,053	(676,897)					
12	Total				$ 16,213	(478,286)	(29.50)	(57.46)	27.96	$ 453,269	$ 1,242
13	**PA PROPERTY TAX**				$ 1,250						
14	First Payment	04/30/27	04/01/27	(29.00)	$ 625	(18,125)					
15	Second Payment	08/31/27	04/01/27	(152.00)	625	(95,000)					
16	Total				$ 1,250	(113,125)	(90.50)	(57.46)	(33.04)	$ (41,304)	$ (113)
17	**PURTA**				$ 1,420						
18	Payment	05/01/27	04/01/27	(30.00)	$ 1,420	(42,600)	(30.00)	(57.46)	27.46	$ 38,989	$ 107
19	Total Working Capital For Other Taxes										$ 4,570

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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Schedule C-4
Witness: A. M. Keller
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Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Miscellaneous	[6] Subscriptions	[7] Postage	[8] Rent	[9] Maintenance & Services
1	September, 2024		17,897	7,651	3,412	385	108	2	-	6,338
2	October		18,551	6,660	3,033	400	280	3	-	8,174
3	November		17,249	6,247	2,654	400	199	3	-	7,746
4	December, 2024		17,645	5,421	2,275	326	118	0	-	9,504
5	January, 2025		16,934	4,526	1,896	571	372	0	-	9,569
6	February		14,804	3,722	1,517	469	545	0	-	8,551
7	March		13,077	2,826	1,137	429	575	2	-	8,108
8	April		10,792	1,968	758	417	648	(3)	-	7,004
9	May		8,657	1,070	379	350	539	4	-	6,315
10	June		7,338	172	-	283	433	5	-	6,445
11	July		9,081	299	-	224	561	2	-	7,996
12	August		16,621	8,732	-	233	399	4	-	7,253
13	September, 2025		18,558	7,869	3,413	180	290	2	-	6,804
14	TOTAL		$ 187,204	$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 57,165	$ 20,475	$ 4,667	$ 5,067	$ 23	$ -	$ 99,807
17	Monthly Average	13		$ 4,397	$ 1,575	$ 359	$ 390	$ 2	$ -	$ 7,677
18	Rate Case Amount		$ 14,400							

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-5
Witness: A. M. Keller
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Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2024	$27,677
2	October	32,669
3	November	32,041
4	December, 2024	25,192
5	January, 2025	15,334
6	February	8,991
7	March	3,692
8	April	11,088
9	May	17,289
10	June	24,134
11	July	30,732
12	August	36,859
13	September, 2025	41,904
14	Total	$ 307,601
15	Number of Months	13
16	Average Monthly Balance	$ 23,662

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule C-6
Witness: D. T. Espigh
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Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (724,029)	
2	Sub-total		(724,029)
3	ADIT on CIAC	39,331	
4	Sub-total		39,331
5	Federal ADIT		(684,698)
6	State Repair Regulatory Liability	(48,917)	(48,917)
7	CIAC Tax Gross-Up Regulatory Liability	(422)	(422)
8	Pro-Rata Adjustment	17,243	17,243
9	Balance At September 30, 2027		$ (716,793)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule C-7
Witness: A. M. Keller
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Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2024	$ 20,721
2	October	$ 21,053
3	November	$ 21,369
4	December, 2024	$ 21,641
5	January, 2025	$ 22,111
6	February	$ 22,868
7	March	$ 24,005
8	April	$ 24,716
9	May	$ 24,801
10	June	$ 24,688
11	July	$ 24,591
12	August	$ 24,522
13	September, 2025	$ 24,475
14	Total	$ 301,560
15	Number of Months	13
16	Average Monthly Balance	$ 23,197

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule C-8
Witness: A. M. Keller
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Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2024	$ 30,420
2	October	30,020
3	November	29,626
4	December, 2024	29,997
5	January, 2025	29,829
6	February	30,374
7	March	29,642
8	April	29,028
9	May	28,754
10	June	27,778
11	July	26,665
12	August	25,527
13	September, 2025	24,707
14	Total	$ 372,366
15	Number of Months	13
16	Average Monthly Balance	$ 28,644

UGI Utilities, Inc. - Gas Division | **Schedule D-1**
Before the Pennsylvania Public Utility Commission | **Witness: T. A. Hazenstab**
Fully Projected Future Period - 12 Months Ended September 30, 2027 | **Page 1 of 1**
($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Pro Forma Test Year Rate Increase	[3] Pro Forma Test Year At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 773,312	$ -	$ 773,312
2	Gas Supply & Cost Adjustment Revenue		448,276	-	448,276
3	Other Revenues		14,131	-	14,131
4	Revenue Increase			98,693	98,693
5	Total operating revenues		1,235,719	98,693	1,334,412
	OPERATING EXPENSES				
6	Manufactured Gas		-	-	-
7	Gas Supply Production		405,467	-	405,467
8	Transmission		-		
9	Distribution		94,027	-	94,027
10	Customer Accounts		62,615	-	62,615
11	Uncollectible Expense	1.723%	20,359	1,700	22,060
12	Customer Information & Services		14,680	-	14,680
13	Sales		1,292	-	1,292
14	Administrative & General		117,117	-	117,117
15	Depreciation & Amortization		170,518	-	170,518
16	Taxes other than income taxes		15,160	-	15,160
17	Total operating expenses		901,236	1,700	902,937
18	Net operating income Before Income Tax		334,483	96,993	431,476
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		50,332		50,332
20	Pro Forma Income Tax on Revenue Increase			26,108	26,108
21	Net Income (loss)		$ 284,151	$ 70,885	$ 355,036

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab
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Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates Budget For Year End 09/30/27	[3] Adjustments Sch D-3 Increase (Decrease)	[4] Pro Forma Adjusted For Test Year 9/30/27	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase	[7] Column [6] As Filed
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]	
1	Residential (R/RT)	480	$ 815,696	$ (20,021)	$ 795,675		$ 795,675	$ 794,638
2	Comm & Ind (N/NT)	481	295,972	(26,918)	269,053		269,053	269,053
3	Comm & Ind (DS)	489	36,322	(313)	36,010		36,010	36,010
4	Lg Transport/Other	489	99,453	(1,546)	97,907		97,907	97,907
5	Interruptible	489	22,870	73	22,944		22,944	22,944
6	Forfeited Discounts	487	6,337	-	6,337		6,337	6,337
7	Miscellaneous Service Revenues	488,489,495	4,790	712	5,502		5,502	5,502
8	Rent from Gas Properties	493	2,292	-	2,292		2,292	2,292
9	Rate Increase			-	-	98,693	98,693	99,368
10	Total operating revenues		1,283,732	(48,012)	1,235,719	98,693	1,334,412	1,334,050
	OPERATING EXPENSES							
11	Gas Production		-	-	-		-	-
12	Gas Supply Production		429,721	(24,254)	405,467		405,467	404,972
13	Transmission		-		-			
14	Distribution		93,549	478	94,027		94,027	94,027
15	Customer Accounts		62,160	455	62,615		62,615	62,571
16	Uncollectible Expense	1.723%	20,671	(312)	20,359	1,700	22,060	22,054
17	Customer Information & Services		14,993	(312)	14,680		14,680	14,666
18	Sales		1,283	8	1,292		1,292	1,292
19	Administrative & General		111,118	5,999	117,117		117,117	118,072
20	Depreciation & Amortization		164,574	5,944	170,518		170,518	170,518
21	Taxes other than income taxes		14,211	949	15,160		15,160	15,249
22	Total operating expenses		912,281	(11,045)	901,236	1,700	902,937	903,422
23	Net Operating Income - BIT		$ 371,450	$ (36,967)	$ 334,483	$ 96,993	$ 431,476	$ 430,628

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab
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Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2]	[3]	[4]	[5]	[6] Adjustments	[7]	[8]	[9]	[10]	[11]	[12] Sub-Total Adjustments	[13] Total Proforma
	OPERATING REVENUES			D-4	Revenues D-5	Gas Costs D-6	Salaries & Wages D-7	Environmental Expense D-8	Other S&W Costs D-9	Rate Case D-10	Uncollectibles Expense D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 466,312		$ (10,176)									$ (10,176)	$ 456,137
2	Comm & Ind (N/NT)	481	172,874		(11,170)									(11,170)	161,704
3	Comm & Ind (DS)	489	35,486		122									122	35,608
4	Lq Transport/Other	489	98,356		(1,437)									(1,437)	96,920
5	Interruptible	489	22,870		73									73	22,944
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	349,384		(9,845)									(9,845)	339,538
7	Comm & Ind (N/NT)	481	123,098		(15,748)									(15,748)	107,349
8	Comm & Ind (DS)	489	836		(435)									(435)	402
9	Lq Transport/Other	489	1,096		(109)									(109)	987
10	Interruptible Transport	489	-		-									-	-
11	Forfeited Discounts	487	6,337		-									-	6,337
12	Miscellaneous Service Revenues	##########	4,790		712									712	5,502
13	Rent from Gas Properties	493	2,292		-									-	2,292
14			-											-	-
15	Total operating revenues		1,283,732		(48,012)	-	-	-	-	-	-	-	-	(48,012)	1,235,719
	OPERATING EXPENSES														-
16	Gas Production		-				-							-	-
17	Gas Supply Production		429,721			(24,254)								(24,254)	405,467
18	Transmission		-												-
19	Distribution		93,549	-			478						-	478	94,027
20	Customer Accounts		62,160				204							204	62,364
21	Uncollectible Expense		20,671								(312)			(312)	20,359
22	Customer Information & Services		14,993				13						-	13	15,006
23	Sales		1,283				8							8	1,292
24	Administrative & General		111,118	-			226	2,363	-	(537)		-		2,052	113,170
25	Depreciation & Amortization		164,574											-	164,574
26	Taxes other than income taxes		14,211											-	14,211
														-	-
27	Total operating expenses		$ 912,281	$ -	$ -	$ (24,254)	$ 929	$ 2,363	$ -	$ (537)	$ (312)	$ -	$ -	$ (21,811)	$ 890,471
28	Net operating income Before Income Tax		$ 371,450	$ -	$ (48,012)	$ 24,254	$ (929)	$ (2,363)	$ -	$ 537	$ 312	$ -	$ -	$ (26,202)	$ 345,249

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-3
Witness: T. A. Hazenstab
Page 2 of 2

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments D-14	[4] Other Adjustments D-15	[5] Universal Service D-16	[6] Adjustments D-17	[7] D-18	[8] EE&C Program D-19	[9]	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
	Customer & Distribution Revenue													
29	Residential (R/RT)	$ 456,137												$ 456,137
30	Comm & Ind (N/NT)	161,704												161,704
31	Comm & Ind (DS)	35,608												35,608
32	Lg Transport/Other	96,920												96,920
33	Interruptible	22,944												22,944
	Revenue for Cost of Gas													-
34	Residential (R/RT)	339,538												339,538
35	Comm & Ind (N/NT)	107,349												107,349
36	Comm & Ind (DS)	402												402
37	Lg Transport/Other	987												987
38	Interruptible Transport	-												-
39	Forfeited Discounts	6,337												6,337
40	Miscellaneous Service Revenues	5,502												5,502
41	Rent from Gas Properties	2,292												2,292
42	-	-												-
43	Total operating revenues	1,235,719	-	-	-	-	-	-	-	-	-	-	-	1,235,719
	OPERATING EXPENSES													
44	Gas Production	-												-
45	Gas Supply Production	405,467												405,467
46	Transmission	-												-
47	Distribution	94,027					-	-						94,027
48	Customer Accounts	62,364			1,624	(1,372)								62,615
49	Uncollectible Expense	20,359												20,359
50	Customer Information & Services	15,006							(326)					14,680
51	Sales	1,292			-									1,292
52	Administrative & General	113,170		3,071	876									117,117
53	Depreciation & Amortization	164,574									5,944			170,518
54	Taxes other than income taxes	14,211										949		15,160
55	Total operating expenses	$ 890,471	$ -	$ 3,071	$ 2,500	$ (1,372)	$ -	$ -	$ (326)	$ -	$ 5,944	$ 949	$ -	$ 901,236
56	Net operating income Before Income Tax	$ 345,249	$ -	$ (3,071)	$ (2,500)	$ 1,372	$ -	$ -	$ 326	$ -	$ (5,944)	$ (949)	$ -	$ 334,483

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule D-5
Witness: S. A. Epler
Page 1 of 1

Adjustment - Revenue Adjustments

Line #	Description	Reference Or Account Number	[1] 2027 Budget	[2] PRO FORMA ADJUSTMENTS Other Adjustments	[3] Rev/PGC Adj Annualization	[4] Total Proforma Adjustments D-5A	[5] Proforma Adjusted At Present Rates
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 466,312	$ (10,176)		$ (10,176)	$ 456,137
2	Comm & Ind (N/NT)	481	172,874	(11,170)		(11,170)	161,704
3	Comm & Ind (DS)	489	35,486	122		122	35,608
4	Lg Transport/Other	489	98,356	(1,437)		(1,437)	96,920
5	Interruptible	489	22,870	73		73	22,944
6	Cust Chg & Distrib Revenue		795,899	(22,587)	-	(22,587)	773,312
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	349,384	(953)	(8,892)	(9,845)	339,538
8	Comm & Ind (N/NT)	481	123,098	(386)	(15,362)	(15,748)	107,349
9	Comm & Ind (DS)	489	836	(435)		(435)	402
10	Lg Transport/Other	489	1,096	(109)		(109)	987
11	Interruptible Transport	489	-	-		-	-
12	Revenue for Cost of Gas		474,414	(1,883)	(24,254)	(26,137)	448,276
							-
13	Total Customer Revenue		1,270,313	(24,470)	(24,254)	(48,724)	1,221,588
14	Forfeited Discounts	487	6,337		-	-	6,337
15	Miscellaneous Service Revenues	488 & 489.3	3,178		-	-	3,178
16	Rent from Gas Properties	493	2,292		-	-	2,292
17	Other Revenues	495	1,612	712		712	2,324
18	TOTAL REVENUES		$ 1,283,732	$ (23,758)	$ (24,254)	$ (48,012)	$ 1,235,719

UGI Utilities, Inc. - Gas Division
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Schedule D-5A
Witness: S. A. Epler
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Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 815,696	$ 795,675	$ (20,021)	
2	Comm & Ind (N/NT)		295,972	269,053	(26,918)	
3	Comm & Ind (DS)		36,322	36,010	(313)	
4	Lg Transport/Other		99,453	97,907	(1,546)	
5	Interruptible		22,870	22,944	73	
6	Total		$ 1,270,313	$ 1,221,588	$ (48,724)	$ (48,724)
COST OF COMMODITY						
7	Residential (R/RT)		$ 349,384	339,538	$ (9,845)	
8	Comm & Ind (N/NT)		123,098	107,349	(15,748)	
9	Comm & Ind (DS)		836	402	(435)	
10	Lg Transport/Other		1,096	987	(109)	
11	Interruptible		0	0	(0)	
12	Total		$ 474,414	$ 448,276	$ (26,137)	$ (26,137)
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 466,312	$ 456,137	$ (10,176)	
14	Comm & Ind (N/NT)		172,874	161,704	(11,170)	
15	Comm & Ind (DS)		35,486	35,608	122	
16	Lg Transport/Other		98,356	96,920	(1,437)	
17	Interruptible		22,870	22,944	73	
18	Total		$ 795,899	$ 773,312	$ (22,587)	$ (22,587)

UGI Utilities, Inc. - Gas Division
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Schedule D-5B
Witness: D. T. Espigh
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Adjustment - CIAC on Tax Gross-Ups

Line #	Description	[1] Factor Or Reference	[2] Other Adjustments	[3] Total
1	Amortization of Tax Gross-up		$ 712	
				$ 712
2	Total ProForma Adjustment			$ 712

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Schedule D-6
Witness: S. A. Epler
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Adjustment - Gas Costs

Line #	Description	[1] Budgeted Gas Costs	[2] PRO FORMA ADJUSTMENTS D-5A Gas Costs	[3]	[4] Gas Cost Pro Forma Adjustments	[5] Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 429,721			$ -	$ 429,721
2	Residential (R/RT)		(8,892)		(8,892)	(8,892)
3	Comm & Ind (N/NT)		(15,362)		(15,362)	(15,362)
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 429,721	$ (24,254)	$ -	$ (24,254)	$ 405,467

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Schedule D-7
Witness: T. A. Hazenstab
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Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/27	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	29,446	-	29,446	340	29,786
5	Customer Account Operations Expenses	17,626	-	17,626	204	17,829
6	Total Cust. Service & Inform. Operations Exp	1,164	-	1,164	13	1,178
7	Total Operation Sales Expenses	715	-	715	8	723
8	Total A & G Operation Expenses	18,619	-	18,619	215	18,834
9	Total Operations	67,570	-	67,570	781	68,351
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	11,944	-	11,944	138	12,082
14	Total A&G Maintenance	912	-	912	11	923
15	Total Maintenance	12,856	-	12,856	149	13,005
16	Total Payroll to Expense	$ 80,426	$ -	$ 80,426	$ 929	$ 81,356
17	Percent Increase					1.156%

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Schedule D-7
Witness: T. A. Hazenstab
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Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Increase At 6-1	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-27		$ 35,161	$ 18,463	$ 27,955	$ 81,578
	Annualize for Wage Increase to 9-30-27					
2	Percent Increase		4.00%	4.00%	4.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/26	67%			
4	Non-Exempt Annualization Factor	10/1/26		0%		
5	Exempt Annualization Factor	10/1/26			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	942	0	0	$ 942
7	Annualized Salaries & Wages at 9-30-27 Rates	L 1 + L 6	$ 36,103	$ 18,463	$ 27,955	
8	Adjustments from Schedule D-9				$ -	
9	Pro Forma Salaries & Wages for TY		$ 36,103	$ 18,463	$ 27,955	
10	Pro Forma Adjustment to S&W					$ 942
11	Annualization Factor	L 10 / L 1				1.155%

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Schedule D-8
Witness: A. M. Keller
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Adjustment - Environmental

Line #	Description	[1] Amount	[2] Total
Environmental Adjustment - #1			
1	2023 Environmental expenditures	$ 5,441	
2	2024 Environmental expenditures	7,602	
3	2025 Environmental expenditures	7,052	
4	Three year average of Environmental expenditures	6,698	
5	Budgeted Environmental Expense	$ 5,429	
6	Pro Forma Adjustment		$ 1,269
Environmental Adjustment - #2			
7	(Over) Recovery through 9/30/2026 Related to Prior Rate Case approvals	$ (914) **(1)**	
8	Under Recovery related to 2025 expenditures	1,880 **(1)**	
9	Under recovered expenditures as of 9/30/2026	$ 967	
10	Amortization Period - 2 years	2	
11	Pro Forma Adjustment	483	
12	Amortization expense for under recovery included in budget	(610)	
13	Pro Forma Adjustment		$ 1,093

(1) See reconciliation of these amounts at UGI Gas Exhibit AMK-2

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Schedule D-10
Witness: T. A. Hazenstab
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Adjustment - Rate Case Expense

Line #	Description	[1] Reference	[2] Amount	[3] Total
	Rate Case Expenditures			
1	External Consultants		$ 917	
2	External Legal		750	
3	Miscellaneous Costs		93	
4	Sub-Total	L 1 to L 3		1,760
	Total Expenditures for Rate Case Filing			
5	TOTAL COSTS	L 4		$ 1,760
6	Normalized over 1 year (Line 5 / Line 6, Column 2)		1	$ 1,760
7	Rate Case Expense included in Budget			2,297
8	Pro Forma Adjustment	L 6 - L 7		$ (537)

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Schedule D-11
Witness: V. K. Ressler
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Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
Adjustment #1:						
1	2023		$ 23,142	$ 1,210,517	1.91%	
2	2024		$ 17,089	$ 1,020,566	1.67%	
3	2025		$ 17,879	$ 1,140,677	1.57%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 19,370	$ 1,123,920		1.723%
5	2027 Budget				$ 21,469	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.723%		$ 1,227,925		
7	Pro Forma at Present Rate Revenue	[1] * [3]			21,157	
8	Total for Test Year					$ (312)

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Schedule D-14
Witness: A. M. Keller
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Adjustment - Benefits Adjustments

Line #	Description	[1] Amount	[2] Subtotal	[3] Pro Forma Adjustment
Pension Expense Adjustment				
1	Total budgeted pension expense (income)		$ 1,437	
2	Total cash contributions per estimate	12,940		
3	Estimated Cash Contributions attributable to UGI Gas	8,049		
4	Less: estimated capitalized portion	(3,541)		
5	Pension cash contributions per updated estimates		4,507	
6	Pro Forma Adjustment - Pension			$ 3,071

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Schedule D-15
Witness: V. K. Ressler
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Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
Injuries & Damages Reserve Adjustment			
1	2023 Injuries & Damages Expense	$ 2,415	
2	2024 Injuries & Damages Expense	2,090	
3	2025 Injuries & Damages Expense	1,083	
4	Three Year Average of Injuries and Damages Expense	1,863	
5	Budgeted Injuries and Damanges Expense	$ 987	
6	Pro Forma Adjustment		$ 876
Customer Accounts Expense Adjustment			
7	Unrecovered Interest on Customer Deposits		$ 1,624
PUC Assesment			
8	2027 Projected PUC Assessment Expense	$ 6,006	
9	Budgeted PUC Assessment Expense	$ 5,131	
10	Pro Forma Adjustment		$ 875

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Schedule D-16
Witness: S. A. Epler
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Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase for Pro Forma TY Universal Service Expense	
1	Customer Assistance Plan Credit	$ 23,005
2	Administration Costs	1,492
3	LIURP	4,693
4	Hardship Program (Project Share)	34
5	Customer Assistance Plan Pre-program Arrearage	3,023
6	TOTAL	$ 32,247
7	Adjusted Budget	$ 30,875
8	Adjustment	$ (1,372)

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Schedule D-19
Witness: S. A. Epler
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Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2027 Original Program Costs	$ 12,366	
2	Adjusted Budget	$ 12,040	
3	Additional Expense Adjustment (Line 2 - Line 1)		(326)
4	Total Adjustment		$ (326)

UGI Utilities, Inc. - Gas Division
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Schedule D-21
Witness: J.F. Weidmayer
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Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/27 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	-	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-	-
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
					-
17	TOTAL PRODUCTION & GATHERING		-	-	-
NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		-	-	-

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Schedule D-21
Witness: J.F. Weidmayer
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Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/27 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	11	(0)	11
32	Structures & Improvements	366	0	(0)	0
33	Mains	367	390	9	399
34	Measuring & Regulating Station Equipment	369	92	(5)	87
35	Communication Equipment	370	92	(15)	77
36	Other Equipment	371	6	(1)	5
37	TOTAL TRANSMISSION		591	(12)	579
DISTRIBUTION PLANT					
38	Land & Land Rights	374	42	0	43
39	Structures & Improvements	375	281	(137)	144
40	Mains	376	51,851	(455)	51,396
41	Measuring & Regulating Station Equipment	378	6,495	(220)	6,275
42	Measuring & Regulating Station Equipment	379	2,057	177	2,234
43	Services	380	56,156	(4,435)	51,721
44	Meters	381	6,804	1,047	7,851
45	Meter Installations	382	3,245	464	3,709
46	House Regulators	383	1,438	(1,232)	206
47	House Regulatory Installations	384	348	(29)	319
48	Industrial Measuring & Reg. Station Equipment	385	953	(156)	798
49	Other Property	386	25	2	27
50	Other Equipment	387	92	(3)	89
51	TOTAL DISTRIBUTION		129,788	(4,977)	124,811
GENERAL PLANT					
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	7,915	1,044	8,959
54	Office Furniture & Equipment	391	23,884	2,473	26,357
55	Transportation Equipment	392	7,087	1,200	8,288
56	Stores Equipment	393	1	0	1
57	Tools & Garage Equipment	394	2,378	(19)	2,360
58	Laboratory Equipment	395	22	0	22
59	Power Operated Equipment	396	915	(82)	833
60	Communication Equipment	397	141	123	264
61	Miscellaneous Equipment	398	67	19	86
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		42,411	4,759	47,170
64	TOTAL DEPRECIATION		$ 172,790	$ (231)	$ 172,559
65	CHARGED TO CLEARING ACCOUNTS		$ (10,522)	$ (1,223)	$ (11,745)
66	NET SALVAGE AMORTIZATION		$ 10,899	$ (1,197)	$ 9,703

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Schedule D-31
Witness: T. A. Hazenstab
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Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Budget Amounts 9/30/27	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/27
1	PURTA Taxes	408.1		$ 1,420	$ -	$ 1,420
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		1,250	-	1,250
4	Social Security	408.1	D-32	6,087	70	6,157
5	FUTA	408.1	D-32	6	-	6
6	SUTA	408.1	D-32	317	4	321
7	PUC Assessment	408.1		5,131	875	6,006
8	Total			$ 14,211	$ 949	$ 15,160

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Schedule D-32
Witness: T. A. Hazenstab
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Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/27 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 80,426	$ 929	
2	FICA Expense		6,087		
3	FICA Expense - Percent	L 2 / L 1	7.57%	7.57%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 70
5	FUTA Expense		6		
6	FUTA Expense - Percent	L 5 / L 1	0.01%	0.01%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		317		
9	SUTA Expense - Percent	L 8 / L 1	0.39%	0.39%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			4
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 74

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Schedule D-33
Witness: D. T. Espigh
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Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,235,719	$ 98,693	$ 1,334,412
2	Operating Expenses			(901,236)	(1,700)	(902,937)
3	OIBIT	L 1 + L 2		334,483	96,993	431,476
	Interest Expense					
4	Rate Base	Sch A-1	4,319,177			
5	Weighted Cost of Debt	Sch B-7	0.02390			
6	Synchronized Interest Expense	L 4 * L 5		(103,228)	-	(103,228)
7	Base Taxable Income	L 3 + L 6		231,255	96,993	328,248
8	Total State Tax Depreciation	Sch D-34	$ 328,424			
9	Pro Forma State Book Depreciation	Sch D-34	177,694			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(150,731)		(150,731)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 80,525	$ 96,993	$ 177,517
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	7.49%	$ (6,031)	$ (7,265)	$ (13,296)
14	Total Federal Tax Depreciation	Sch D-34	$ 310,652			
15	Pro Forma Federal Book Depreciation	Sch D-34	177,694			
16	Federal Tax Deducts (Over) Under Book	L 15 - L 14		(132,959)	-	(132,959)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		92,265	89,728	181,993
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(19,376)	(18,843)	(38,218)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(25,407)	(26,108)	(51,514)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 172,559			
22	Total Tax Depreciation	L 15 - Sch D-34 L 2	299,318			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		126,759	-	126,759
24	Deferred Federal Taxable Income	L 23		$ 126,759	$ -	$ 126,759
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(22,607)	-	(22,607)
	Deferred State Income Taxes					
26	Repairs			(2,943)		(2,943)
27	CIAC			26		26
28	State Deferred Income Tax (Expense)/Refund			(2,917)	-	(2,917)
29	Net Income Tax Expense	L20 + L 25 + L28		(50,931)	(26,108)	(77,038)
	Other Tax Adjustments					
30	ITC			599		599
31	Combined Income Tax Expense	L 29 + L 30		$ (50,332)	$ (26,108)	$ (76,439)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (41,383)	$ (18,843)	$ (60,226)
33	State Income Tax Expense	L 13 + L 28		(8,948)	(7,265)	(16,213)
34	Total Income Tax Expense	L 32 + L 33		$ (50,332)	$ (26,108)	$ (76,439)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

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Schedule D-34
Witness: D. T. Espigh
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Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 211,544	
2	Cost of Removal		11,334	
3	Repairs Tax Deduction		110,774	
4	Other Tax Basis Adjustments		(23,000)	
5	Total Federal Accelerated Tax Depreciation			$ 310,652
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		17,772	
7	Total State Accelerated Tax Depreciation			$328,424
	Straight Line Tax Depreciation			
8	Gas Plant		$ 172,559	
9	Total Tax Depreciation			$ 172,559
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 172,559	
11	Net Salvage Amortization		9,703	
12	Depreciation Charged to Clearing Accounts	(11,745)		
13	Estimated Percent of Clearing Charged to CWIP	38.9%		
14	Depreciation Charged to CWIP		(4,569)	
15	Book Depreciation for Tax Calculation			$ 177,694

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Witness: T. A. Hazenstab
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Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.017230)
3	NET REVENUES	Sum L 1 to L 2		0.982770
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	7.4900%	(0.073609)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.909161
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.190924)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.718237
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.392298
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		26.453%
INCOME TAX FACTOR				
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	7.4900%	(0.074900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.925100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.194271)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.730829
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.368309
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		26.917%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 3-R

Rebuttal Testimony of
Jill E. Walter

Topics Addressed:	**Pipeline Replacement Costs**
	Methane Detectors
	Training Protocols
	Public Input Hearing Testimony

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jill E. Walter. My business address is 2121 City Line Avenue, Bethlehem, PA 18107.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 3, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain claims in the testimony of the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") Witness Anna Ritchie, I&E Statement No. 4; Office of the Consumer Advocate ("OCA") Witness Barbara Alexander, OCA Statement 5; and OCA Witness Zachary Teti, OCA Statement 7.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I'm sponsoring UGI Gas Exhibit JEW-1R.

II. RESPONSE TO TESTIMONY

A. PIPELINE REPLACEMENT COSTS

Q. Did you review the testimony of I&E Witness Anna Ritchie?

A. I did.

Q. Do you have any response to her discussion of the Distribution Integrity Management Plan ("DIMP") and the Long Term Infrastructure Improvement Plan ("LTIIP")?

A. Witness Ritchie accurately describes the regulatory requirements of the DIMP and the LTIIP. I&E St. No. 4, at pp. 3-6. Her testimony states that UGI Gas determines pipeline replacements by managing the risk ranking of the different aspects of the pipeline and then replacing the pipe based on the highest risk ranking. I&E St. No. 4, pp. 6-7. I wanted to provide further clarity regarding the Company's process. UGI Gas generally prioritizes pipeline replacement to remove the highest amount of risk while taking into consideration cost efficiencies. For example, UGI Gas will reprioritize a replacement project when there is an opportunity to work in conjunction with a third party, such as a municipality that is planning paving projects, to reduce the overall cost of the project. Further, the Company may need to reorder its work based on other timing considerations. For example, municipalities often limit pipeline replacement projects after a paving project, which could impact UGI Gas's ability to replace the pipeline at a later date, making the reprioritization more cost effective and operationally necessary. Finally, while UGI Gas prioritizes its project list by the pipeline with the highest risk ranking, the Company may include pipelines of lower risk in the vicinity of the highest risk pipeline project due to cost efficiency. In these examples, in addition to the cost savings and operational efficiencies, the local community also benefits by reducing street disturbances that avoid repeated road closures and other traffic disruptions.

Q. Witness Ritchie claims that UGI Gas's annual pipeline replacement costs have been increasing due, in part, to rising restoration costs. I&E St. No. 4, at pp. 11-12. Do you agree with the way Witness Ritchie characterized the data?

A. Yes. Restoration costs associated with replacing and retiring natural gas mains have increased steadily over the life of the Company's accelerated main replacement program articulated in its LTIIP. UGI Gas has taken many active steps aimed at controlling restoration costs where it is possible to do so.

Q. Does Witness Ritchie make any recommendations?

A. Yes. Witness Ritchie recommends that UGI Gas continue to take positive steps toward reducing restoration costs by coordinating pipe replacement projects with other street projects and incorporating trenchless construction techniques where it is economically feasible. I&E St. No. 4, at p. 14. Witness Richie also states that UGI Gas should work to negotiate with state, county, and local entities to reduce restoration requirements associated with pipeline replacement. She further states that UGI Gas should analyze and consider these costs on a project-by-project basis in an effort to continue to decrease and draw down these replacement costs annually. I&E St. No. 4, at p. 14.

Q. What steps has UGI Gas taken towards reducing restoration costs?

A. The Paving & Restoration team at UGI Gas proactively engages with municipalities to develop and partner in cost-share agreements, when possible. The Company also negotiates and contests permit fees, and addresses and negotiates requests for additional restoration work. This ongoing collaboration has led to improved project outcomes and

better working relationships with local municipalities. In addition, UGI Gas seeks opportunities to replace pipelines ahead of municipality planned paving projects to reduce UGI Gas's overall project costs.

Despite these advancements with some municipalities, the team has encountered challenges, particularly in navigating the differing expectations and requirements of various municipalities regarding restoration standards and associated costs. The team's commitment to enhancing alignment and oversight remains focused. With continued development, these efforts are anticipated to refine the process of data collection and review, ultimately fostering greater transparency in restoration initiatives throughout the UGI Gas territory. Over the last year, UGI Gas has met and collaborated with various stakeholders in its North and South regions including the cities of Allentown, Bethlehem, Lancaster, Harrisburg, and Scranton as well as South Whitehall Township.

Q. What other factors contribute to the increased cost of restoration?

A. There has been a significant increase in municipal costs related to the installation of American with Disabilities Act ("ADA") ramps. These ramps are crucial for accessibility compliance but often go unaddressed by municipalities unless and until UGI Gas engages in utility projects. These ADA ramp upgrades add a tremendous cost to the restoration of UGI Gas projects and include, at times, traffic signal upgrades and pedestrian crossings, and installing ramps where no ramps previously existed to bring the intersections up to code. For example in the City of Allentown, UGI Gas completed 10 restoration projects costing approximately $1.34 million of which approximately $815,000 was related to ADA ramps (~61% of the total paving costs).

Q. Witness Ritchie claims that increasing restoration costs diverts funds from UGI Gas's pipeline replacement projects. Do you agree?

A. No. The Company will continue to meet its legal and regulatory obligations. However, in a time where customer affordability is a central concern, additional costs that are added to critical safety work – and particularly of the magnitude of the City of Allentown example – will be impactful to customers. Regardless, UGI Gas will continue looking for opportunities to manage the impact of restoration costs on its pipeline replacement work.

B. METHANE DETECTORS

Q. Does Witness Ritchie offer any testimony about the Company's deployment of methane detectors?

A. Yes. I&E St. No. 4, at pp. 7-11.

Q. Could you summarize that testimony?

A. Witness Ritchie describes UGI Gas's pilot program to deploy methane detectors, including the deployment of Smart Remote Methane Detectors (SRMDs). I&E St. No. 4, pp. 7-8. She describes the Company's Ambassador Program, where over 200 methane detectors have been placed in the homes of UGI Gas employees, who act as ambassadors to increase education and awareness of the program. I&E St. No. 4, at p. 7. She also describes how UGI Gas has taken steps to reach out to customers where a gas leak was recently detected to give them the opportunity to request a methane detector and acknowledges that UGI has sent 212 units as of March 13, 2026. I&E St. No. 4, at p. 8. She further notes that the use of indoor methane detectors are supported by both PHMSA and the National

Transportation Safety Board (NTSB). I&E St. No. 4, at pp. 8-9. It is important to note that UGI Gas has deployed standalone methane detectors that are unable to communicate in over 200 employees' homes and in 212 customers' homes. At this time, UGI Gas has deployed 8 SRMDs in employees' homes.

Q. Does I&E make any recommendation regarding the implementation of methane detectors for UGI Gas customers?

A. Yes. Witness Richie recommends that UGI Gas be required to file quarterly reports with the Commission regarding its methane detector pilot program. I&E St. No. 4, at pp. 10-11. Her testimony identifies specific metrics that should be included in those reports, such as the number of remote and smart methane detectors funded, installed, and the types of customers receiving the detectors, etc. Witness Richie also provides a report template as I&E Exhibit No. 5 with her testimony, which she proposes the Company be required to complete and file.

Q. Do you agree with I&E's recommendations?

A. No. While UGI Gas believes accurate reporting on its pilot will provide the Commission and parties with valuable insight, I&E's proposed quarterly filings are likely too frequent to reflect meaningful progress between reports. UGI Gas supports annual progress reports, and a final report at the conclusion of the pilot that reflects lessons learned over the life of the program.

Q. Does Witness Richie make any further proposals regarding the deployment of smart remote methane detectors, in particular?

A. Witness Richie proposes that UGI Gas's pilot program be expanded to require the installation of 3,000 SRMDs. I&E St. No. 4, at p. 9. Further, Witness Richie suggests that UGI Gas should work to expand its pilot deployment to all customers.

Q. Do you agree with I&E's recommendations?

A. No. UGI Gas opposes the proposal to expand its pilot at this time. Fundamentally, the pilot should be allowed to proceed as originally planned, because it was designed to collect data on efficacy, adoption rates, and cost effectiveness, as well as other information that would inform a larger, programmatic deployment of methane detectors in the future.

Q. Are there any other reasons that I&E's proposal should not be adopted at this time?

A. Yes, as described in the Company's responses to discovery (attached hereto as UGI Gas Exhibit JEW-1R), the technology and feasibility of SRMDs is still in a nascent state and may not be appropriate for more widespread deployment across UGI Gas's service territory. In addition, there are still concerns around cost effectiveness and operational issues that must be evaluated before further scaling deployment. Operational issues include incorporation of response protocols to methane detector alerts, adoption of supporting technology tools, integration of appropriate IT systems, implementation of ongoing maintenance requirements/responsibilities for the devices, as well as other key issues that will affect the successful implementation of this technology on a widespread basis. Large

scale IT upgrades to support the pilot are not prudent, at this preliminary stage, without substantial understanding of the results and potential for future expansion.

C. TRAINING PROTOCOLS

Q. Did you review the testimony submitted by OCA Witness Alexander?

A. I did.

Q. Did Witness Alexander raise any concerns regarding the Company's training materials?

A. Yes. Witness Alexander expresses concern regarding the nature of the training provided to existing and new field technicians, and the timeline for training. Specifically, it is her belief that these employees should be trained to solicit or inquire about customer rights. Finally, Witness Alexander believes that door knocks should be required during terminations. OCA St. 5, at pp. 14-15.

Q. Do you have a response to Witness Alexander's concerns?

A. Yes. Field Technicians are responsible for in-person contact and the physical termination of service in the field. However, they are not trained to function as customer service representatives or to assess sensitive customer matters such as medical conditions or income status. As such, they are not the appropriate resource to solicit or evaluate this type of information.

Customers are provided with multiple notifications outlining their rights and available protections, including written correspondence such as the initial notice, 10-day notice, and post-termination notice. These communications clearly explain customer rights,

including protections related to medical conditions, income eligibility, and protections under the Protection From Abuse Act (PFA), as applicable. These communications also provide the customer with information on who to contact to get additional assistance.

Q. Has the Company taken any proactive steps to support customers that may be in need of assistance?

A. Yes. To further support customers who may be in distress, UGI Gas has reimplemented its Gatekeeper Program, originally established in 2014. This program provides employees with a dedicated resource to report concerns when a customer appears to be in an unsafe condition. Rather than placing field technicians in the position of soliciting or evaluating sensitive personal information, employees are trained to recognize observable indicators—such as health concerns, confusion or disorientation, unsafe home or equipment conditions, or potential hoarding situations—and refer those concerns through the Gatekeeper process.

Once reported, UGI's Outreach team follows up to connect the customer with appropriate partner agencies that are properly equipped to assess needs and provide support. This approach ensures that customers receive appropriate assistance while maintaining employee safety and aligning responsibilities with trained resources and respecting the dignity of the customer.

Requiring field technicians to solicit this type of personal information in the field presents safety risks, as it may lead to escalated situations. The Gatekeeper Program provides a safer, more appropriate alternative that supports both customer care and privacy, as well as UGI employee safety.

D. PUBLIC INPUT HEARING TESTIMONY

Q. Did you review the testimony of Witness Ivan Ritz, who testified at the Lancaster Public Input Hearing?

A. Yes, I did. I also reviewed the testimony of OCA Witness Zachary Teti, OCA St. 7, describing Mr. Ritz's testimony.

Q. Mr. Ritz describes work completed in Lancaster by UGI contractors as well as the impact of that work on his neighborhood and service. Tr. at 87-94. Has the Company investigated the work at issue in Mr. Ritz's testimony?

A. Yes. In his testimony, Mr. Ritz describes a situation where UGI Gas contractors performed work near Mr. Ritz's home, and where they damaged a fiber optic cable. I have investigated this claim. During the summer of 2025, UGI Gas, through a UGI subcontractor, conducted main and service replacement work on the 700 and 800 blocks of East Orange Street in Lancaster City. Prior to construction, Verizon failed to mark its underground conduit lines after facility markout requests were made through the Pennsylvania One Call System. During construction, a piercing tool struck and damaged the unmarked conduit. The damage was reported to 811. Verizon indicated in response to the 811 report that the conduit was abandoned. Because the conduit was no longer active, work continued. At this time, there was no damage or issues with Mr. Ritz's service. Weeks later, on October 29, 2025, Verizon informed Kinsley, the UGI subcontractor, that the conduit previously struck was still active and that Verizon was experiencing service issues. Kinsley and UGI Gas responded promptly to address Verizon's service issues. It was found that Mr. Ritz's gas service was impacting Verizon's duct bank, which required his gas service to be relocated. The relocation required a temporary disconnect. The

temporary disconnect was completed at 1:20 pm on October 29, 2025 and a door hanger was placed on Mr. Ritz's door with information on how to request a relight. Mr. Ritz called for a relight at 3:26 pm. An order was dispatched, and a field technician restored Mr. Ritz's service at 4:33 pm on October 29, 2025.

Q. Based on your review of the circumstances, did UGI Gas and its contractor act with a reasonable level of professionalism?

A. Yes. The Company recognizes that construction activity over an extended period can be disruptive, and UGI Gas makes every effort to minimize impacts to our customers and communities. However, these pipeline replacement projects are essential to maintaining the safe and reliable operation of UGI's natural gas system. In this case, Verizon did not mark its conduit as required under Pennsylvania One Call Law and subsequently incorrectly advised that the facility was abandoned. UGI Gas treats service interruptions involving other utilities with the same level of urgency that we would expect for our own facilities. As a result, it was necessary to perform a temporary disconnection of service while Mr. Ritz was not at home in order to safely address the situation. But the Company responded promptly when Mr. Ritz called and restored his service expeditiously.

Q. In reviewing the operating circumstances around Mr. Ritz's experience, do you agree with Mr. Teti's characterization of the event?

A. No, I do not. UGI Gas and its subcontractors followed proper protocol, including reporting the incident and responding promptly when Verizon indicated that it was having service issues. Further, the Company was on site to restore service a mere one hour after the

customer called. If anything, this prompt response shows UGI Gas's commitment to quickly and effectively meeting the needs of its customers.

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit JEW-1R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-7

Request:

Reference Direct Testimony of Jill E. Walters Statement 3, page 19, lines 15-18. Provide results for how the Natural Gas Safety Ambassador program has progressed since its implementation. Describe how UGI Gas has implemented the planned 500 Methane Detectors (MDs) and Smart Remote Methane detectors (SRMDs) and how it continues to distribute them over the two-year pilot program. Describe how many MDs and SRMDs have been implemented to date.

Response:

UGI has joined a Gas Technical Institute, GTI, project studying cellular communicating SRMDs along with other utilities across the country. As part of this project, the participating utilities were given cellular communicating units from two different manufacturers' for installation at customer premises. UGI has installed all of the SRMDs that it received from the GTI project. Both manufacturers SRMDs will notify UGI when 10% LEL is reached at the unit at which UGI will respond.

UGI targeted installation of these SRMDs in employees' homes who also had an inside gas meter. Through the work to identify and communicate with its employees to find participants for this pilot program, UGI discovered that there is a lack of awareness and education on the availability of Natural Gas Detectors.

This is when UGI initiated the Natural Gas Safety Ambassador program. This program was established to educate UGI employees on Natural Gas Detectors. UGI has used many different communication methods including emails, message boards, intranet postings, and a town hall presentation to bring awareness of these Natural Gas Detectors to its employees.

Since the start of the Natural Gas Safety Ambassador program, over 200 UGI employees, that are also UGI Gas customers, have received a Natural Gas Detector for their home and in doing so have become advocates to their family and friends in leading gas safety as a shared responsibility.

After this strong internal base of Natural Gas Safety Ambassadors had been established, UGI looked to reach out and educate its customers. UGI started the Natural Gas Detector Program in February 2026. A targeted marketing letter campaign was established to reach out to customers who have had a recent odor complaint inside their home and upon our

UGI Utilities, Inc. - Gas Division
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I&E-PS-7 (Continued)

visit, the UGI technician found natural gas readings. As of 3/13/2026, this mailing has targeted 1,355 customers. From those letters UGI has collected 228 requests and as of 3/13/26 the company has shipped out 212 units to those customers. A copy of the communication is attached as Attachement-I&E-PS-7.

In addition to this targeted marketing, UGI has either completed or is in development of other ways to contact and educate customers about the availability and importance of having Natural Gas Detectors in their homes. These activities include:

- A company website dedicated to Natural Gas Detectors education
- Updates to Call Center scripts
- 3rd party storefront to host UL 1484 tested Natural Gas Detectors for customers to purchase
- Education to 4th grade classrooms
- Educational materials accompanying the scratch and sniff mailers
- Call Center on hold messaging
- Customer newsletters

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-9

Request:

Describe the considerations for installing an MD or SRMD in the homes of UGI Gas customers.

Response:

The installation considerations for the MD and SRMD are different. For the MD, UGI has taken the approach of sending the units to the customers and providing them with the installation instructions from the manufacturer as well the manufacturer installation video. For SRMD, UGI had UGI technicians complete the installation in UGI employees' home or UGI owned facilities where UGI owned piping inside the building. During this installation, the UGI technician would complete an inside SLIP (Service Line Inspection Program) investigation to look for leaks before installation.

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-10

Request:

Describe the considerations to determine which methane detector will be installed.

Response:

Options for testing were limited since not many units on the market are tested in accordance with UL 1484 (safety standard for residential gas detectors). This left UGI with two manufacturers with units for testing, eLichens & DeNova Detect.

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-11

Request:

Describe what percentage of MD/SRMDs currently use Advanced Metering Infrastructure (AMI) technology within the pilot program. Provide a summary of the geographical areas that are served by AMI technology and how UGI Gas plans to disperse more AMI technology.

Response:

None of the SRMDs will be tested on an AMI infrastructure because UGI does not have an AMI. This is why UGI is evaluating the use of SRMDs that are cellular connected, allowing for their deployment to not be tied into the presence of an AMI network.

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-12

Request:

Provide an estimated cost per meter and the timeframe to install the SRMD technology.

Response:

UGI is working in partnership with GTI and other peer utilities on testing cellular communicating SRMD. At the conclusion of this GTI project UGI expects to have data to develop the cost and feasibility to scale into a SRMD technology. This will include not just the cost per unit to be installed but also the background system to support the communications.

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (PS-1 thru PS-19)
Delivered on March 20, 2026

I&E-PS-13

Request:

Provide an estimated cost per meter and the timeframe to install audible methane detectors.

Response:

The MD that UGI has been providing to customers are available at most hardware stores and many online retailers. Prices range for the stand-alone Natural Gas detector to combined units with CO sensors for ~$90-110. UGI has currently been paying an additional $12 to ship these MDs to customers' homes.

Prepared by or under the supervision of: Jill E. Walter

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-45-46)
Delivered on April 8, 2026

I&E-RE-45

Request:

Reference the Company's response to I&E-PS-9, I&E-PS-12, and I&E-PS-13 concerning the methane detector pilot program. Provide the following:

A. State the quantity of audible methane detectors (MDs) that have been delivered to customers since the inception of the methane detector pilot program.

B. State the total quantity, since inception of the methane detector pilot program, of Smart Remote Methane Detectors (SRMDs) expected to be fully installed by the end of the Fully Projected Future Test Year (FPFTY) and how many meters are designated to be installed in the FPFTY.

C. State what percentage of each of the following is funding the installation costs for the SRMDs pilot program: UGI Gas, Gas Technical Institute (GTI), or the UGI Gas customer.

D. Identify where the costs for the SRMD pilot program are claimed in the current filing for the FTY and the FPFTY and the associated amounts disaggregated by account and year.

E. If any of the SRMDs installation costs or hardware is capitalized, identify the accounts, the amounts, and the associated depreciation expense claimed, disaggregated by year for the FTY and FPFTY.

Response:

A. As of 3/27/26, 458 MD have been delivered to customers. This count excludes the SRMDs.

B. A total of 8 SRMDs are currently installed. At the conclusion of the pilot program with GTI, UGI will be evaluating what additional technology, resources and options there are in order to determine if SRMDs could be incorporated with UGI systems. As of today, UGI has no plans to expand the SRMD pilot program outside of the Operations Technology Development (OTD) project. The OTD project is expected to conclude in 2026. UGI will not be installing any meters in relation to the SRMD pilot.

UGI Utilities, Inc. - Gas Division
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Responses to I&E (RE-45-46)
Delivered on April 8, 2026

I&E-RE-45 (Continued)

C. The costs for the SRMDs units were covered in the membership cost to join the GTI's OTD partnership. As members of OTD, UGI has voting power to guide and select research projects that address emerging technology solutions that address common gas industry issues. The installation costs associated with the 8 SRMDs were included in the Inside SLIP inspections that occurred during the installations.

D. The costs for the SRMD pilot program are included in the GTI membership fee. Please refer to I&E-RE-46 for details.

E. The installation costs were not capitalized for the current SRMD units. There are no future planned expenses related to the SRMD pilot at this point and time.

Prepared by or under the supervision of: Jill E. Walter

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 4-R

Rebuttal Testimony of
Vivian K. Ressler

Topics Addressed: **Updates To Initial Filing**
Operating Expense Adjustments

Dated: May 13, 2026

INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 4, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain components of the Company's filing, based on the information provided during the discovery phase of this proceeding. In addition, my testimony responds to certain portions of the following direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission" or "PUC") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1, the direct testimony of Zachari Walker; and OCA Statement 2, the direct testimony of Jennifer L. Rogers.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits VKR-1R through VKR-3R.

UPDATES TO INITIAL FILING

Q. Since the filing of your direct testimony, has the Company identified any operating expense components of its filing that should be updated?

A. Yes, in addition to items discussed in detail by other Company witnesses, and summarized by Company witness Tracy A. Hazenstab in her rebuttal testimony (UGI Gas Statement No. 2-R), the Company has also identified the following operating and maintenance ("O&M") expense items that required revision for the Fully Projected Future Yest Year ("FPFTY"):

- The Company has reduced its payroll, payroll tax, and employee benefits expenses by $1,153,000, $88,000 and $764,000, respectively, to reflect an increase in its vacancy rate to 6.15%.

As with the other updates to the Company's claim, this revision to the Company's operating expenses is reflected in UGI Gas Exhibit A – Fully Projected (REBUTTAL), which is the Company's final accounting exhibit. UGI Gas witness Tracy A. Hazenstab sponsors this exhibit as part of her rebuttal testimony (UGI Gas Statement No. 2-R).

OPERATING EXPENSE ADJUSTMENTS

A. PAYROLL AND PAYROLL-RELATED EXPENSES (VACANCY RATE ADJUSTMENT)

Q. Do any of the other parties recommend an adjustment to the Company's claimed payroll expenses?

A. Yes. I&E Witness Walker and OCA Witness Rogers each propose adjustments to the Company's claimed payroll and payroll-related expense.

Q. Please describe the basis for this proposed adjustment.

A. Both I&E Witness Walker and OCA Witness Rogers propose to adjust the Company's payroll, payroll tax, and employee benefits expenses based upon the application of a 6.15% vacancy rate to the calculation of these expenses. I&E St. No. 1, at pp. 17-23; OCA St. 2, at pp. 11-12. Both I&E and OCA use an average of the actual monthly vacancy rate experienced by UGI Gas for the last three years to calculate their proposed vacancy rate of 6.15%. As a result, I&E proposes to decrease the Company's payroll, payroll tax, and employee benefits expenses by $1.15 million, $88,000, and $764,000, respectively. OCA proposes to reduce payroll, payroll tax, and employee benefits expenses by $1.1 million, $87,663, and $265,685, respectively. OCA St. 2, at p. 12; Schedule JLR-9 through 11.

Q. Does the Company agree with either I&E's and OCA's proposed adjustments to payroll, payroll taxes, and employee benefits expense based upon the use of an alternative vacancy rate?

A. While the Company believes that it appropriately accounted for vacancies as a part of its initial claim, it is willing to accept the use of a 6.15% vacancy rate as proposed by I&E and OCA in order to limit the scope of issues in dispute in this proceeding.

Q. What is the impact to the Company's claim of applying a 6.15% vacancy rate as proposed by I&E and OCA?

A. The impact to the Company's claim is a net decrease to its revenue requirement of $1,153,000 to payroll expense, $88,000 to payroll taxes expense, and $764,000 to employee benefits expense, as proposed by I&E Witness Walker. These updates are reflected in Schedule D-2 of UGI Gas Exhibit A – Fully Projected (REBUTTAL).

B. INCENTIVE COMPENSATION EXPENSE

Q. Do any of the other parties propose an adjustment to the Company's claim to recover the costs of certain of its incentive compensation plans?

A. Yes. At a high level, I&E proposes to disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** I&E St. No. 1, at pp. 36-42. OCA also proposes to disallow approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** OCA St. 2, at pp. 8-10.

Q. Before detailing your responses to the specific plans and amounts that I&E and OCA target for disallowance, do you have any general response to these parties' proposals?

A. Yes. The crux of I&E's and OCA's arguments appears to be that the Company has claimed incentive compensation expenses related to various plans that utilize financial performance metrics, and assert that those metrics are not meant to align the interests of the covered recipients with ratepayers. In order to provide gas service to its customers, UGI Gas must be able to attract and retain qualified employees, managers and executives. UGI Gas's ability to attract and retain qualified individuals into these positions is directly related to its ability to provide them with reasonable and competitive compensation. I&E's and OCA's attempts to disallow certain aspects of the Company's total compensation packages fundamentally undermines the Company's ability to attract qualified employees, managers and executives, and would fail to produce just and reasonable rates for the cost of providing customers with safe and reliable service.

And, relatedly, it is important to recognize that neither I&E nor OCA has asserted that the amounts claimed by UGI Gas are excessive or unreasonable due to imprudent management or decision-making by UGI Gas. I am advised by counsel that UGI Gas will further address this issue in its briefs.

Q. Do you have any response to the claim that plans or portions of plans designed to align the covered recipients' interests with shareholders should be disallowed? I&E St. No. 1, at pp. 37-38; OCA St. 1, at pp. 8-10.

A. Yes. Ultimately, UGI must attract sufficient capital at reasonable costs to fund necessary and critical infrastructure investments. All else equal, if the financial performance of UGI was to diminish or decrease, investors would likely view it as being a "higher risk" investment, which would adversely impact (i.e., increase) its cost of capital. In this regard, these incentive compensation plans are designed to ensure that the financial performance of UGI is such that it can continue to attract necessary investments at reasonable costs, for the benefit of its ratepayers. Moreover, as explained in detail below, many of the financial metrics identified by I&E and OCA actually have direct, important, and beneficial impacts upon the service provided by UGI Gas to its ratepayers. The same actions that allow the Company to be financially successful, such as managing expenses and growing customer base, help the ratepayers.

Q. Are there other reasons why the Commission should reject these arguments?

A. Yes. The Commission has previously rejected proposed adjustments to other utilities' claims for incentive compensation, including stock-based compensation. In PPL Electric

Utilities Corp.'s ("PPL Electric") 2012 base rate proceeding, witnesses on behalf of I&E and the OCA recommended disallowance of half of PPL Electric's performance compensation expense claim, thereby requiring shareholders to share equally in the cost of its performance compensation plan. The Commission rejected that proposal:

> We find that, because PPL's incentive compensation plan is reasonable, prudently incurred, and is not excessive in amount, PPL is permitted full recovery of this expense. PPL correctly notes that many of the cases the OCA and I&E rely on are distinguishable from this case because, in those cases there was not adequate evidence that the incentive compensation expense was reasonable or that there was a benefit to ratepayers. Our decision to allow this incentive compensation expense is consistent with our prior decision approving incentive compensation programs that are focused on improving operational effectiveness.

Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2012-2290597, at p. 26 (Final Order entered December 28, 2012) (internal citations omitted).

The Commission again made clear in the 2018 UGI Electric base rate proceeding that incentive compensation programs must be evaluated "as a whole," when determining whether the plan includes goals which benefit customers. *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, at pp. 73-74 (Order entered Oct. 25, 2018). By breaking apart the Company's incentive compensation program into individual components, I&E and OCA inappropriately try to single out individual aspects of the Company's total incentive compensation program, when, as a whole, the program clearly contains "both financial and operating metrics and goals which benefit customers," consistent with the Commission's order in 2018 UGI Electric base rate proceeding. *Id.*, at p. 74.

Furthermore, the Commission again applied this reasoning in *Pa. PUC, et al v. Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc.*, Docket Nos. R-2021-

3027385, R-2021-3027386, et al. (Order entered May 16, 2022) ("*Aqua PA 2021 Order*"). There, the Commission affirmed a utility's total incentive compensation package because:

> Aqua has provided evidence linking the stock-based incentive compensation program with benefits to customers and improved operational efficiency….
>
> We agree with the ALJ that the stock-based compensation benefits ratepayers. We find that the stock-based compensation is linked to performance objectives that benefit consumers, including controlling costs and compliance initiatives.

Aqua PA 2021 Order, at pp. 100-101.

Moreover, the Commission again affirmed this reasoning in *Pa. PUC, et al. v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, et al. (Order entered July 22, 2024) ("*PAWC 2024 Order*"). In the *PAWC 2024 Order*, the Commission specifically affirmed recovery of stock-based incentive compensation expense, including expenses related to performance stock units ("PSUs") and restricted stock units ("RSUs") and allocation of such expenses from a corporate parent to a utility, because "PSUs reflect the Company's financial performance, and improved financial performance can benefit customers by encouraging operational efficiency. . . RSUs vest over a three-year period, encouraging employee retention which can benefit ratepayers by maintaining experienced employees." *PAWC 2024 Order*, at pp. 88-89.

Finally, these programs also work in conjunction with other incentive compensation programs, as well as base compensation, to incentivize and retain the talented workforce responsible for UGI Gas's operations. The Company's stock options and restricted stock awards typically become exercisable three years after being awarded and become void when an employee leaves the Company. Therefore, the stock options and restricted stock award grants serve as an incentive to retain employees, thereby

reducing transition costs. Finally, if the Company did not offer these stock compensation awards, alternative incentive compensation or base compensation (e.g., salary) would be necessary to allow the Company to retain its workforce in a competitive job market.

Q. Do you have any further general observations regarding why I&E's and OCA's proposed adjustments to the Company's incentive compensation claim should be rejected?

A. Yes. Neither I&E nor OCA has argued that UGI Gas's method of compensating its employees, managers, directors, or executives, as a whole, is unreasonable. Rather, the evidence of record demonstrates that UGI Gas compensates these individuals consistent with industry standards and in a reasonable manner that permits the Company to attract and retain qualified employees in order to provide safe and reliable service to its customers. I&E's and OCA's attempts to single out specific aspects of the Company's overall compensation program—where the evidence otherwise demonstrates the overall program is reasonable—is improper and should be rejected.

Q. Please respond to I&E's specific proposal to disallow [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the Company's claimed incentive compensation expense based on its argument that this amount is "unsupported." I&E St. No. 1, at p. 37.

A. I&E Witness Walker appears to have overlooked the Company's claim for equity compensation plans for UGI Corp. employees. The Company's claim for equity compensation for UGI Corp. employees is **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** However, this amount is not included in the list of incentive compensation at I&E St. No. 1, at p. 37. The remaining **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which Witness Walker claims is unsupported relates to other employee compensation which consists of amounts for retention awards, signing bonuses and similar ad hoc amounts.

Q. For clarity, will you please define the plans under which equity compensation is provided?

A. Equity compensation (both to UGI Corp. employees and UGI employees) is provided under the 2004 Omnibus Equity Compensation Plan, 2013 Omnibus Incentive Compensation Plan, and 2021 Incentive Award Plan. These plans are collectively referred to as the "Long-Term Incentive Compensation Plan".

Q. Please explain the purpose of the UGI Corp. equity compensation.

A. The Long-Term Incentive Compensation Plan for UGI Corp. employees is designed to work in conjunction with the UGI Corp. Executive Bonus Plan and the UGI Corp. Non-Executive Bonus Plan (which both provide cash awards for the achievement of performance goals established annually), base salary, and the UGI Corp. employee benefit programs to attract, retain and motivate qualified employees. Retention is further encouraged through a three-year vesting period for awards. Long-Term Incentives comprised of equity compensation awards are a standard benefit for publicly-traded companies, including utility and energy companies. The lack of such an incentive would

put UGI Corp. at a distinct disadvantage to other employers, particularly with regard to key roles in which continuity is critical to operational stability.

Q. Please comment on the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] claim for other employee compensation.

A. The other employee compensation incorporates retention awards, signing bonuses, referral bonuses and similar ad hoc awards. These types of awards are needed to attract or secure high-performing employees. Retention awards can entice key employees to stay with the Company when they are assigned to critical projects or when they have competing offers. Signing bonuses are often needed to adequately compensate a highly-skilled candidate who might otherwise not accept an offer due to the timing of payout on an existing employer's incentive award. The Company offers referral awards to existing employees for recommending a successful candidate, as this recruitment technique generally proves to be more cost-efficient and effective than using an external recruiter.

Q. Should the Commission adopt I&E's proposal to disallow all costs associated with the Sales Commission Plan ("SCP") and Inside Sales Group ("ISG")? I&E St. No. 1, at p. 37.

A. No. The SCP and ISG plans award employees who successfully onboard new customers. As the Company's customer base grows, the Company's fixed costs are spread over a larger base of customers, resulting in lower costs per customer. These growth-based incentives motivate this specific performance which benefits existing customers. Additionally, these

incentives are necessary to be competitive with non-utility sales roles where commission-based bonuses are a common practice.

Q. Please address I&E's proposal to disallow the entire [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] expense claim and entire [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] capital expenditure claim related to the Long-Term Incentive Compensation Plan. I&E St. No. 1, at pp. 37-38.

A. The awards issued under the Long-Term Incentive Compensation Plan are restricted stock awards and stock options granted to key employees of UGI based on employment contracts and in management's discretion. These awards typically have a vesting period of three years.

Q. To provide context, can you please explain the purpose of the Long-Term Incentive Compensation Plan?

A. The Long-Term Incentive Compensation Plan is designed to work in conjunction with the UGI Management Incentive Plan, the UGI Executive Bonus Plan (which both provide cash awards for the achievement of performance goals established annually), base salary, and the UGI employee benefit programs to attract, retain and motivate qualified employees. Retention is further encouraged through a three-year vesting period for awards. Long-Term Incentives comprised of equity compensation awards are a standard benefit for publicly-traded companies, including utility and energy companies. The lack of such an incentive would put UGI at a distinct disadvantage to other employers, particularly with

regard to key roles in which continuity is critical to operational stability. Examples of such roles include:

- **VP of Operations** – Leads and directs field-level activities, including emergency response and underground main marking, ensuring safe and reliable day-to-day service delivery.
- **VP of Supply and Measurement –** Oversees the procurement of natural gas supply for default customers, maintaining the uninterrupted flow of natural gas to the customers who depend on it for heating and/or industrial fuel.
- **VP of Customer Relations –** Directs all customer-facing interactions, including management of the contact center that handles emergency calls, serving as a critical link between UGI and the customers it serves.

Without a competitive compensation package, including the equity compensation component, the Company would be at risk of losing experienced employees in these critical roles. If there was unexpected turnover in these roles, the Company's ability to provide the safe and reliable natural gas service that customers rely upon would be in jeopardy.

Q. Please address I&E's claim to disallow [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the expense claim and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the capital expenditure claim related to the FY 2026 Management Incentive Plan. I&E St. No. 1, at p. 38.

A. The claims for disallowance are based on the premise that "40% of this incentive plan's criteria are based on financial performance and thus are inappropriate for ratemaking purposes." I&E St. No. 1, at p. 38. The specific criteria which I&E Witness Walker has labeled as financial performance are related to capital investment (10%); capital placed in service (10%) and annualized margin growth (20%). For the capital placed in service goal, a minimum number of miles of pipeline must be replaced to achieve the trigger for the payout.

Q. Do you agree with I&E Witness Walker's characterization of these goals as based on financial performance and inappropriate for ratemaking purposes?

A. No.

Q. Please explain.

A. I will begin with the capital investment and capital placed in service goals. The characterization of capital investment and capital placed in service as "financial performance" metrics misapprehends the nature of these goals. Capital investment and capital placed in service measure the Company's operational execution: whether work is actually being planned, contracted, and completed in the field. These are project delivery metrics. They reflect the physical progress of infrastructure modernization that regulators and ratepayers expect the Company to achieve.

Q. How do the Company's ratepayers benefit from capital investment and capital placed in service?

A. As the Company invests in capital and places that capital into service, ratepayers benefit from a safer, more reliable distribution system, and supporting infrastructure. The Company must continue to modernize its gas distribution system, as well as its information technology platforms—such as geospatial mapping, customer information systems, and work order management systems—to serve its customers efficiently and safely. The inclusion of these goals in the management incentive compensation plan is intended to motivate employees to complete these projects which benefit ratepayers. Critically, the

capital placed in service goal is triggered only after an established mileage replacement target is met, ensuring that this goal is grounded in a measurable, operational outcome that has direct implications for customer service via improvements to the Company's distribution system.

Q. Please comment on the annualized margin growth metric from the Company's Incentive Compensation Plan.

A. While margin is a financial measure, the annualized margin growth goal should not be characterized as a purely financial metric that services shareholder interests alone. Organic customer growth allows the Company to spread fixed costs across a larger customer base, reducing the per-customer cost of service. If such growth is sufficient, it can also extend the period between base rate cases, further moderating costs for existing ratepayers. The margin growth metric also incentives adding large customers, which may bring additional contributions such as Universal Service Plan ("USP") and Distribution System Improvement Charge ("DSIC"), as proposed within the XD tariff in this proceeding. In this way, margin growth that is driven by organic customer additions serves as a proxy for the health and expansion of the system the Company is obligated to serve — a result that benefits ratepayers and shareholders alike.

Q. Please summarize your comments on I&E's proposal to disallow a portion of the expense claim and a portion of the capital claim associated with the Management Incentive Plan.

A. All of the metrics within the Management Incentive Plan are designed to motivate the Company's employees toward actions which benefit its ratepayers. Specifically:

- **OSHA Recordable Injury Rate and Accountable Vehicle Incident Rate –** A safer workforce means fewer service disruptions, lower workers' compensation and liability costs, and more consistent delivery of natural gas services to customers.

- **Gas Emergency Response Rate –** Requiring UGI Gas responders to arrive on-site within 45 minutes of an emergency call directly protects the safety of customers and the communities the Company serves. This 45 minute response time goal well exceeds the Commission's benchmark of 60 minutes.

- **Gas Total Excavation Damage Rate –** Reducing damage to underground facilities protects the safety of customers and surrounding communities by minimizing the risk of gas leaks, fires, and explosions. It also protects system integrity, lowers repair costs, and prevents service interruptions for ratepayers.

- **Customer Satisfaction (Verint CSAT) and Grade of Service** – These metrics measure the quality of direct interactions between the Company and its customers, incentivizing employees to provide responsive, high-quality service to ratepayers.

- **Capital Investment and Capital Placed-in-Service –** As discussed above, these metrics drive physical infrastructure modernization that produces a safer, more reliable system for ratepayers.

- **Aggregate Annualized Margin (Growth) –** As discussed above, organic customer growth spreads fixed costs across a larger base, reducing the per-customer cost of service and benefiting existing ratepayers.

Therefore, the entire expense claim and the entire capital claim associated with the Management Incentive Plan should be allowed for ratemaking purposes.

Q. Please address I&E's claim to disallow the entire [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] expense claim and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] capital expenditure claim related to the FY 2026 UGI Utilities & UGI Utilities Segment Executive Annual Bonus Plan. I&E St. No. 1, at pp. 39-40.

A. The UGI Utilities & UGI Utilities Segment Executive Annual Bonus Plans provides executives with a prudent level of compensation that benefits ratepayers by enabling the Company to attract and retain the executive talent necessary to ensure the Company's long-term financial health and operational stability.

Performance-based incentive compensation at the executive level is standard practice both within the utility industry and across industries generally. To compete for experienced executives capable of leading a company of UGI's size and complexity, the Company must offer a compensation package — including an annual incentive component — that is competitive in the marketplace. Moreover, if the Company did not offer such an incentive component, it would, all else equal, likely need to increase base, non-incentive pay for these individuals to remain competitive. By structuring a portion of executive compensation as performance-based rather than fixed, the Company aligns executive interest with utility-specific outcomes that benefit ratepayers. Failing to offer a competitive compensation program — and the resulting inability to attract and retain qualified executive leadership — would expose the Company to operational and strategic risks that would ultimately fall on ratepayers.

The connection to ratepayer benefit is direct and concrete. UGI's financial strength and stability allow the Company to access debt financing at reasonable rates and to attract the investment capital necessary to fund its ongoing infrastructure modernization program. That modernization program, in turn, is what delivers the safe and reliable gas service that ratepayers depend on. Disallowing compensation expense that supports the executive leadership responsible for maintaining that financial strength would undermine the very

outcomes — infrastructure investment, system safety, and service reliability — that the regulatory framework is designed to protect.

Q. Please address I&E's claim to disallow the entire [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] expense claim related to the FY 2026 UGI Corp. Executive Annual Bonus Plan. I&E St. No. 1, at p. 39.

A. The UGI Corp. Executive Annual Bonus Plan is similar to the plans discussed previously which provide compensation to UGI Utilities' executives; however, this plan is for the executives at the UGI Corp. level. The cost of this plan is allocated to the business units owned by UGI Corp., including UGI. The cost allocated to UGI is further allocated to UGI Gas and UGI Electric.

The compensation paid under the UGI Corp. Executive Annual Bonus Plan benefits ratepayers for the same reasons as the UGI Utilities & UGI Utilities Segment Executive Annual Bonus Plan, described above.

Q. Please address I&E's claim to disallow the entire [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the expense claim related to the UGI Corp. Non-Executive Annual Bonus Plan. I&E St. No. 1, at p. 39.

A. The UGI Corp. Non-Executive Annual Bonus Plan is a prudently incurred compensation expense that benefits ratepayers by enabling the Company to attract and retain professional management talent necessary to ensure that UGI Corp's corporate functions are operated effectively and efficiently.

These functions include treasury, insurance, human resources, cyber security, investor relations and talent acquisition, among others. While most of these professionals do not interact directly with UGI Gas customers, they perform the essential back-office and support functions that underpin the Company's ability to operate safely, attract debt finance and investment capital, recruit and retain the employees who serve customers directly, and maintain the overall organizational stability on which reliable service depends.

To attract and retain qualified professionals in these functional roles, the Company must offer a compensation package that is competitive in the marketplace. Performance-based incentive compensation is a standard component of such packages across industries. Disallowing this expense would impair the Company's ability to staff these critical functions at a level of competence that ultimately serves ratepayer interests.

Q. What does OCA recommend regarding the Company's claim for incentive compensation expense?

A. Similar to I&E, OCA recommends disallowing portions of the Company's claimed incentive compensation expenses, claiming that 80% of certain plans are based upon financial performance metrics/criteria that it argues are designed to increase shareholder value and do not benefit ratepayers. OCA St. 2, at pp. 8-9; Schedule JLR-7. Additionally, OCA recommends complete disallowance of the Company's equity compensation claim. Schedule JLR-7. This proposal results in a reduction of $6.7 million to the Company's O&M expense claim.

Q. Do you have any initial comments regarding the construction of OCA's incentive compensation disallowance?

A. Yes. The text within OCA Witness Rogers's testimony which describes her requested disallowance was unclear to me. However, I was able to understand her requested disallowance by reviewing her Schedule JLR-7 which supports the $6.7 million disallowance that Witness Rogers mentions within the text of her testimony.

Q. Please respond to OCA's proposed adjustment related to incentive compensation expense.

A. I do not agree with OCA's proposed adjustment. For the reasons described above, I believe that the Company's incentive compensation plans do benefit ratepayers. Each of these incentive compensation plans is an integral component of the Company's comprehensive compensation program which allows the Company to attract and retain leaders who direct the provision of safe and reliable service to customers.

Further, the plans for which OCA Witness Rogers proposes to disallow 80% of the claimed compensation (Utilities and Utilities Segment Executive Annual Bonus Plans; UGI Corp. Executive Annual Bonus Plan; and UGI Corp Non-Executive Annual Bonus Plan) are all goals-based incentive compensation which motivate the Company's talent.

C. EMPLOYEE ACTIVITES EXPENSE

Q. Do any of the other parties oppose the Company's claim for expenses related to Employee Activities?

A. Yes. I&E Witness Walker recommends that Employee Activities costs be reduced by $195,000 to remove the cost of the Company picnic. I&E St. No. 1, at pp. 29-30. Witness

Walker claims that "Company picnics do not directly support the provision of safe and reliable gas service, and therefore should not be funded by ratepayers." I&E St. No. 1, at p. 30.

OCA Witness Rogers recommends disallowing the Company's entire claim of $583,036 in employee activities expense. OCA St. 2, at pp. 10-11. She claims that these costs "do not aid in the provision of service but rather are for items such as a picnic and awards." OCA St. 2, at pp. 10-11.

Q. Does the Company agree with these adjustments?

A. No.

Q. Why not?

A. Starting with OCA Witness Rogers, it is important to note that her proposal to disallow the entirety of the Company's claim for employee activities expenses seeks to disallow the costs associated with the Company picnic, but would also disallow $233,000 associated with safety, service and performance awards and $155,000 for activities such as department meetings and field employee welfare. I&E Witness Walker did not propose to disallow the costs associated with safety, service and performance awards, or department meetings and field employee welfare, presumably in recognition that these costs directly reflect or aid in the provision of quality service to customers.

In response to OCA Witness Rogers's disallowance of these service-oriented costs, I will address each category of activities and awards in turn:

- **Safety awards** recognize employees for exemplary performance in two critical areas: avoidance of personal injuries and safe vehicle operation. These safety awards are a

component of the Company's strong safety culture, directly reducing workplace incidents, which in turn reduces costs borne by ratepayers through lower workers' compensation claims, reduced service disruptions, and fewer liability exposures.

- **Service awards** recognize employment anniversary milestones and serve a dual purpose: honoring long-tenured employees for their sustained contributions, and signaling to less-experienced colleagues the value of a stable career with UGI Gas. Workforce continuity and institutional knowledge are operational assets — experienced employees perform work efficiently and safely, to the direct benefit of customers.

- **Performance Awards** recognize employees for exemplary contributions to the Company's core values and mission. Annual prestigious awards — including the President's Award and the Energy to Do More Volunteer Award for community service — are presented at a Company-wide town hall, publicly honoring employees whose conduct reflects the Company's values. Peer-nominated recognition awards reinforce those same values at the departmental level on an ongoing basis. Together, these awards foster a workplace culture in which employees are motivated to perform at a high level and embody the standards that produce safe, reliable, and efficient service — outcomes that directly benefit customers.

- **Departmental meetings** facilitate information sharing, safety briefings, procedure updates, and the development of working relationships between the field employees and Company leadership.

- **Employee welfare** provides food and hydration to field employees working outdoors in variable weather conditions and reflects a basic duty of care that supports sustained productivity. Employees who are adequately supported perform their work more effectively and safely — completing service calls, responding to emergencies, and maintaining the system that ratepayers depend on.

So, at a minimum, OCA's proposal to disallow all employee activity and award costs should be rejected.

With respect to the Company picnic, both I&E and OCA fail to recognize that the picnic is intended to recognize employee contributions, boost morale, promote team building, and foster a positive work environment. Like its other awards, and activities expenses, the picnic has the goal of recognizing and celebrating employees for meeting milestones and for outstanding performance, which leads to increased employee engagement, productivity, and retention.

Q. Has the Commission previously addressed UGI's company picnic?

A. Yes. The Commission has previously affirmed that employee activities expense, and specifically the Company picnic, can be recovered in rates. In *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Opinion and Order entered October 25, 2018) ("*UGI Electric 2018*"), the Commission concluded "that UGI's annual picnic is an employee recognition event which the utility may properly claim as an expense for inclusion in the rate base." *UGI Electric 2018*, at pp. 70-71. The Commission further discussed precedent related to this category of costs and explained that such costs are recoverable if there is an element of employee recognition at the event. *See UGI Electric 2018*, p. 71.

Each of the categories of expenses proposed to be disallowed by I&E and OCA have an element of employee recognition, as discussed above.

D. ADVERTISING EXPENSE

Q. Do any of the other parties address the Company's claim to recover certain advertising expenses?

A. Yes. Both I&E and OCA propose disallowances regarding different categories of advertising expense. I will discuss these proposals in turn.

Q. Please summarize I&E's recommendation related to the Company's claimed advertising expenses.

A. I&E Witness Walker proposes to disallow $646,000 in advertising costs, inclusive of two parts. I&E St. No. 1, at pp. 24-28. First, he proposes the use of the sum of the historical

two-year averages for the Company's advertising related to Public Health and Safety, Conservation of Energy, Explanation of Bill Practices, and Stakeholder Newsletters, which reduces the Company's claim by $455,000. Second, he proposes to disallow all costs related to Community Event Sponsorships, which reduces the Company's claim by $191,000.

Q. Please respond to the first part of I&E Witness Walker's adjustment.

A. I disagree that the use of a two-year average represents a more appropriate level of projected expenses during the FPFTY. The cost of procuring space for advertising — newspapers, radio spots, billboards, mailings, and digital ads — continues to increase.

- **Public Health and Safety -** The Company plans to continue its widespread "Smell Gas Act Fast" public safety messaging campaign. Additionally, the Company now mails scratch and sniff safety notices to all customers twice a year (an increased frequency in 2025 and future years compared to 2024 and prior). The increasing cost to expand this critical public safety message, including the mailing and postage costs, is reflected within the Company's claim.

- **Conservation of Energy –** The Company's campaign for energy conversion comprises this category of advertising spend. The costs of an energy conversion marketing campaign can vary from year to year, based on the extent of the messaging. The Company sees most effective results when it pairs direct mailings with digital ads, reaching potential customers within a short distance of existing or planned gas mains. Assisting customers in reducing their energy use, including through conversion to gas from other fuel sources, provides direct cost reduction benefits to customers that participate and long-term benefits to all ratepayers by increasing the number of customers paying into system costs and increasing the efficient use of existing infrastructure.

- **Explanation of Bill Practices -** The Company now purchases space in the main section of newspapers (rather than in the legal section) and in more widely-circulated editions (weekend, rather than weekday), increasing the effectiveness of messaging but also increasing the cost of noticing.

- **Stakeholder Newsletters -** These newsletters provide information on ongoing Company activities and initiatives, as well as educating on key utility issues. However, the cost of production continues to increase as professional design services and postage costs both continue to increase.

Q. Please respond to I&E Witness Walker's adjustment for community event sponsorships.

A. UGI Gas uses community event sponsorships as a means of connecting with the communities in which it provides services. As UGI Gas and its employees develop a presence, customers can connect with the Company and receive information about billing, customer programs, safety, or utility services. At certain events, the Company can present information about gas safety, which is important to all community members and is part of the Company's responsibility to keep the public safe. For example, UGI Gas's sponsorship of the Big Brothers Big Sisters Bowl-a-Thon opened the door to deeper community involvement through the organization's "Beyond School Walls" program, in which UGI employee mentors meet with local Cocalico high school students approximately twice a month to discuss career development topics. I personally served as a mentor during the 2025/2026 school year. During a recent session at UGI's headquarters in Denver, Company professionals from Engineering, Damage Prevention, and Communications not only showcased career opportunities within the utility industry but also delivered important safety messages—such as calling 811 before digging and recognizing the smell of natural gas—using hands-on demonstrations including pipes damaged by excavators and scratch-and-sniff brochures for the gas odorant. When the session concluded and the facilitator asked the students what number to call before digging, every student responded "811!"—a clear demonstration that community sponsorships can serve as an effective vehicle for delivering critical public safety messaging.

These sponsorship opportunities also ensure that the Company's potential customer base remains aware of the Company and the services it provides, and they serve as an attraction for potential customers and employees. UGI Gas's sponsorship of the Building Industry Association of Lancaster County provides another compelling example of ratepayer benefit. This sponsorship gives UGI access to builders who construct homes primarily across Lancaster, Lebanon, Dauphin, and Cumberland Counties, and includes participation in events such as the annual Parade of Homes Gala and a golf outing that create valuable networking opportunities with those builders. The sponsorship provides opportunities to promote the UGI brand not only to builders but also to prospective customers, supporting customer growth. As new customers connect to the UGI Gas system, the costs of the Company's operations are spread across a larger customer base—ultimately reducing the per-customer cost burden and benefiting existing ratepayers.

Q. How do these community sponsorships satisfy the requirements of 66 Pa.C.S. § 1316(a)?

A. I am advised by counsel that UGI Gas will address these legal requirements in brief. However, I would note that these sponsorships relate to organizations and events located within UGI Gas's service territory. UGI Gas regularly works to educate members of the public, including those that are not currently customers, about natural gas safety. Non-customers may visit locations which are fueled by natural gas and benefit from understanding how to respond in case of a natural gas emergency. UGI Gas also has an opportunity to inform members of the public about the benefits of using natural gas, and

some of these people may choose to convert to natural gas, thereby expanding UGI Gas's customer base with the benefits described above.

Q. Please summarize OCA's recommendation related to the Company's claimed advertising expenses.

A. OCA Witness Rogers recommends disallowance of $81,187 in advertising costs related to fuel-conversion advertisements, claiming this is a non-recurring expense. OCA St. 2, at p. 13. OCA Witness Rogers further recommends disallowance of $191,149 in advertising costs related to community event sponsorships on similar grounds as I&E. OCA St. 2, at p. 14.

Q. Do you agree with OCA's proposal to disallow fuel conversion advertisement costs?

A. No. The marketing campaigns that the Company runs focused on fuel conversion helps to attract new customers. The Company currently plans to continue these campaigns on a regular basis (at least annually) and, therefore, the costs are a normal and recurring cost for the Company.

With energy affordability top of mind for many Pennsylvanians, educating customers about the long-term cost savings available through natural gas conversion — as an alternative to fuel oil, propane, or electric heat — is more critical than ever. This focus serves as a central purpose of this campaign. The conversion campaign is designed to educate the public on the role natural gas can play in lowering their winter heating bills, and helps consumers understand this process and connect with UGI Gas professionals who can assist them with making the switch to natural gas as an affordability measure.

Particularly for those customers using fuel oil and propane, conversion to natural gas will not only save them money, but also connect them to the key consumer protections available as part of utility service.

Q. Do you agree with OCA's proposal to disallow the Company's claim for community event sponsorship costs?

A. No. I disagree with OCA Witness Rogers for the same reasons I explained regarding I&E Witness Walker's proposal for these costs.

E. MEMBERSHIP DUES EXPENSE

Q. Do any of the other parties oppose the Company's claim for recovery of certain membership dues or subscription expenses?

A. Yes. I&E Witness Walker proposes to disallow $383,000 in membership dues from the Company's claim. I&E St. No. 1, at pp. 31-34. I&E Witness Walker specifically proposes to disallow $246,000 of costs related to the Company's membership with the Gas Technology Institute (GTI). I&E St. No. 1, at pp. 31-32. The remaining $137,000 of his proposed disallowance is related to chambers of commerce and economic development agencies based upon his argument that these costs are not necessary for the provision of safe and reliable gas service. I&E St. No. 1, at pp. 32-34.

Q. Does the Company agree with I&E's proposal to disallow a portion of the costs it incurs to maintain membership in GTI?

A. No.

Q. Why not?

A. I&E focuses on the increase in the Company's dues for its membership in this organization, and his claim that the Company has not provided an explanation regarding these increases. The Company has supplemented its response to I&E-RE-13, to provide additional detail for the increases applicable to GTI since 2023. A copy of this supplemental response is attached hereto as UGI Gas Exhibit VKR-1R. As explained therein, the nature of the Company's fees paid to GTI changed significantly from 2023 to 2025, because the Company changed the type of membership it had. The 2023 and 2024 expense related to a limited and one-time membership in the Emerging Technology Program, primarily in support of its energy efficiency program. In 2025, the Company began participation with GTI's Operation Technology Development ("OTD") program. This membership allows the Company to participate in and benefit from a wide range of advanced technology research and development activities. While the payment in 2023 and the new expanded membership were both paid to vendor "GTI" in the Company's payment system, the level of membership and engagement has expanded under the current OTD program.

Importantly, I&E does not claim that UGI Gas's membership in this organization fails to provide safety and reliability benefits. As described in the testimony of UGI Gas Statement No. 1 (Hans G. Bell) in the previous UGI Gas base rate case (Docket No. R-2024-3052716), OTD's projects focus on improving the safety, reliability, and operational efficiency of natural gas projects. This program supports access to best practices related to key areas of research, information, and investments in ongoing areas of focus which are of material interest to UGI Gas in support of the ongoing efficient maintenance and operation of a safe and reliable distribution network. For example, as discussed by UGI

Gas witness Jill E. Walter in this case (UGI Gas Statement No. 3), UGI Gas has joined a project under OTD studying cellular communicating Smart Remote Methane Detectors, among other projects in which UGI Gas is involved. Involvement in this study will produce direct and tangible results that are central to current safety initiatives in Pennsylvania that I&E is focused on. I&E St. No. 4, at pp. 7-11.

Q. Does the Company agree with I&E's proposal to disallow the costs associated with the Company's membership in certain chambers of commerce and economic development agencies?

A. No.

Q. Please explain why not.

A. The Company's membership in these organizations allows it to grow its customer base, primarily by attracting new industrial and commercial customers. These organizations work primarily with large commercial companies who are making site selections, and the Company's active involvement in these organizations allows it to proactively work with these entities, promoting the benefits of natural gas for their energy needs and encouraging them to select sites that are located in close proximity to existing gas mains within the Company's service territory. Without membership and active involvement in these organizations, the Company would experience less commercial growth, resulting in higher costs passed on to individual ratepayers (including its residential customers).

Additionally, over the last decade, economic development corporations and chambers of commerce have been instrumental in attracting more than $8 million in grants

that supported the expansion of UGI Gas's distribution network. See a listing of these grants at UGI Gas Exhibit VKR-2R. While these grants are obtained by commercial customers for their service needs, the network expansions create opportunities for additional prospective customers (including residential customers) located close to UGI Gas's expanded network to connect to natural gas service affordably.

F. PUC ASSESSMENT EXPENSE

Q. Do any of the parties recommend an adjustment to UGI Gas's claim related to the annual PUC Assessment charge?

A. Yes, OCA does.

Q. Please summarize OCA's recommendation.

A. OCA Witness Rogers recommends that the Company's claim be reduced by $1.8 million. OCA St. 2, at p. 14; Schedule JLR-14. She claims that this assessment does not consistently grow year over year, which justifies the use of a three-year average of this expense. OCA St. 2, at pp. 13-14.

Q. Does the Company agree with OCA Witness Rogers' recommendation?

A. No.

Q. Why not?

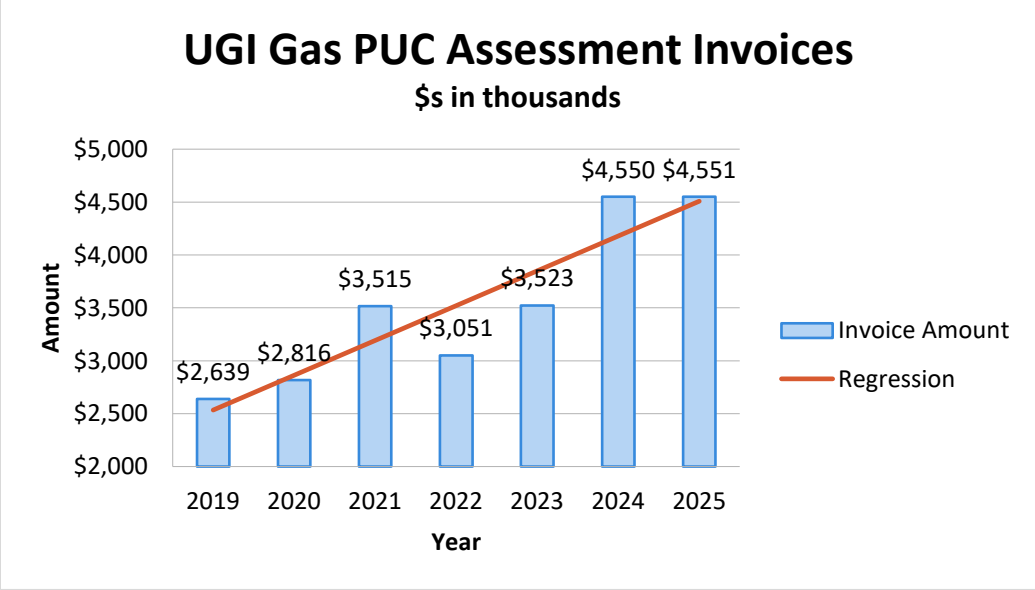
A. The Company agrees with Witness Rogers that the PUC assessment amount varies from year to year. However, the Company does not believe that using an average of the past three years is a reasonable way to calculate the FPFTY PUC assessment to UGI Gas.

Q. Please provide background information on how the PUC assessments for Pennsylvania utilities (including UGI Gas) are calculated.

A. The Commission summarizes the budgets from the Commission, Office of Small Business Advocate, Office of Consumer Advocate, and Damage Prevention Committee (collectively, the "agencies"). That budget is then allocated to each utility operating in the state under the PUC's jurisdiction via a percentage of the utility's gross intrastate operating revenues for the preceding calendar year. After completing the budget allocation process, the Commission sends general assessment invoices to the utilities to advise each utility of the amount of assessment that utility owes.

Q. Please provide a summary of the PUC assessment invoices that UGI Gas has received from 2019 through the most recent (2025).

A. The amounts of each invoice, as well as a regression line showing the trend, are shown in the chart below:



Q. What do you observe from the chart above?

A. While the amount of UGI Gas's PUC Assessment invoice has varied from year to year over the cited period, the overall trajectory shows a steep increase over this period. Specifically, the invoices have grown from $2,639,000 in 2019 to $4,551,000 in 2025 — an increase of approximately 72% over six years. The regression line shown in the chart reflects an average increase of approximately $319,000 per year over this period.

Q. Based on the trajectory in the chart above, does the Company believe that it is appropriate to project the Company's FPFTY (2027) PUC Assessment invoice based on a three-year historical average, as suggested by OCA Witness Rogers?

A. No. Based on the current trajectory, UGI Gas's 2027 PUC Assessment is likely to exceed the three-year historic average of $4,208,000 suggested by OCA Witness Rogers.

Q. Have you prepared any schedules to demonstrate how accurately OCA's method and the Company's method would have projected the 2025 UGI Gas PUC Assessment invoice?

A. Yes. Please see Exhibit VKR-3R. This schedule applies both methods as if projecting the 2025 invoice (the most recent actual invoice).

Q. What are the results of applying both OCA's method and UGI Gas's method of projecting the 2025 invoice?

A. The UGI Gas trending method projected a 2025 invoice of $4,188,000 – understating the actual $4,551,000 invoice by only $363,000, or approximately 8%. By contrast, OCA's

three-year average method projected only $3,363,000, understating the actual invoice by $1,188,000, or approximately 26%. The Company's method is thus more than three times as accurate as OCA's method when applied to the most recent available data point.

Q. Why is the Company's method of calculating its claim for the FPFTY (2027) PUC Assessment more reliable than the method used by OCA Witness Rogers?

A. The Company's method of calculating considers the reality that the PUC's and other agencies' costs will continue to increase over time. As the PUC and the other agencies continue to address the needs of Pennsylvania utility customers and the public utilities that serve them, it is reasonable to assume that the costs to maintain or expand its skilled workforce will continue to increase and that non-payroll costs will be influenced by inflation. Witness Rogers' method of calculating the cost does not take these cost pressures into account. If adopted, her adjustment would put the Company in jeopardy of not fully recovering these required PUC assessment costs that are a necessary part of providing safe and reliable service to its customers and over which the Company has no control. Based on historic performance, even the Company's methodology is likely to understate the actual expense that will be incurred in the FPFTY, but it is a more accurate forecast based on both historic trends and the anticipated future conditions in the FPFTY than what Witness Rogers has offered.

CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit VKR-1R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E-RE (Supplemental Responses)
Delivered on May 6, 2026

I&E-RE-13 (Supplemental Response)

Request:

Reference UGI Gas Book II, Attachment SDR-RR-30, concerning membership dues. Provide the following:

A. Identify the account name and number where membership dues are claimed in the FPFTY.

B. A similar schedule for FY 2023, FY 2024, the HTY, the FTY year-to-date, and the projected FTY.

C. A detailed explanation for any increases by fiscal year from FY 2023 through the FPFTY.

D. A detailed breakdown by payee and amount of the $6,823 for payments to organizations of $1,500 or under.

E. For each payee identified in response to Part C above, identify the expense amount incurred in FY 2023 through the FTY year-to-date, and forecasted for the FTY.

F. A detailed explanation for why the payment to each payee identified in Attachment SDR-RR-30 and in response to Part A above is necessary for safe and reliable natural gas distribution service.

Response:

A. The majority of memberships are claimed in 9302 - Miscellaneous General Expenses, with the exception of Pipeline Association for Public Awareness, which is claimed in 9301 - General Advertising Expenses.

B. Please see Supplemental Attachment I&E-RE-13.1.

C. Increases are generally due to costs to retain memberships. For GTI specifically, the Company purchased a limited annual membership in an Emerging Technology Program, primarily in support of its energy efficiency and conservation program. This limited membership was allowed to expire at the end of calendar 2023 (in Fiscal Year 2024).

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
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I&E-RE-13 (Supplemental Response) (Continued)

Beginning in February 2025, the Company entered into a membership agreement with GTI for involvement in the Operations Technology Development ("OTD") R&D program. This program allows UGI Gas and other participating utilities to combine interests, expertise and resources into focused R&D projects. This OTD membership was discussed in UGI Gas's previous base rate case (Docket R-2024-3052716), on page 38 of the Direct Testimony of UGI Gas Witness No. 1 (Hans G. Bell).

To make the difference between memberships more clear, the GTI membership in the Emerging Technology Program and the membership in the OTD program are shown on separate lines on Supplemental Attachment I&E-RE-13.1.

D. Please see Supplemental Attachment I&E-RE-13.1.

E. Please see Supplemental Attachment I&E-RE-13.1. Forecast is equal to Projected for the period March - September of Fiscal 2026 (FTY). "FTY - YTD" is the first five months of Fiscal 2026 (actuals for Oct. 2025 through Feb. 2026). "FTY - Projected" is the remaining seven months of Fiscal 2026 (projected for March 2026 through Sept. 2026). Together "FPY - YTD" and "FPY - Projected" total Fiscal 2026.

F. Please see Supplemental Attachment I&E-RE-13.2.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF COMPANY MEMBERSHIPS
FOR THE FISCAL YEARS 2023-2027

Organization Name	2023	2024	2025	FTY - YTD** 2026	FTY - Projected 2026	FPFTY 2027	
AMERICAN GAS ASSOCIATION	769,436	662,797	722,304	183,361	553,133	779,316	*
GAS TECHNOLOGY INSTITUTE:							
EMERGING TECHNOLOGY PROGRAM	25,000	6,250	^				
OPERATIONS TECHNOLOGY DEVELOPMENT (OTD)			344,500	344,500	21,746	371,457	
ENERGY ASSOCIATION OF PA	161,744	174,374	206,938	-	201,402	216,732	*
NORTHEAST GAS ASSOCIATION	55,000	57,750	80,649	57,750	710	59,419	
ECONOMIC DEVELOPMENT OF LANCASTER	33,000	24,750	37,080	25,000	7,500	32,500	
PA CHAMBER OF BUSINESS AND INDUSTRY	28,713	30,175	63,350	25,000	4,278	30,733	*
ENERGY SOLUTIONS CENTER	19,380	-	20,800	21,500	-	21,500	
LEHIGH VALLEY ECONOMIC DEVELOPMENT CORP	20,000	20,000	20,000	7,500	12,500	20,000	
GREATER READING ECONOMIC PARTNERSHIP	14,500	14,500	14,880	15,287	-	15,000	
LEBANON VALLEY ECONOMIC DEVELOPMENT CORP	7,500	7,500	7,500	7,500	-	7,500	
WYOMING VALLEY CHAMBER OF COMMERCE	7,000	7,000	2,145	1,000	6,000	7,000	
PENN NORTHEAST - GAS DIVISION	5,500	5,500	5,500	-	5,500	5,500	
BETHLEHEM ECONOMIC DEVELOPMENT CORP	5,500	2,500	2,500	-	5,000	5,000	
SCRANTON CHAMBER OF COMMERCE	5,000	3,000	3,000	-	3,750	3,750	
WYOMING COUNTY CHAMBER OF COMMERCE	5,000	2,150	2,145	1,000	1,145	2,500	
GREATER SUSQUEHANNA CHAMBER OF COMM	5,000	2,050	2,050	2,224	-	2,500	
PIPELINE ASSOCIATION FOR PUBLIC AWARENESS	1,647	1,647		1,840	660	2,500	
HARRISBURG REGIONAL CHAMBER & CREDC	1,739	1,738	1,790	-	1,790	2,000	
WEDCO - WAYNE ECONOMIC DEVELOPMENT COMPANY	5,000	-	1,500	-	1,750	1,750	
ERM CONSULTING & ENGINEERING INC.	5,625	-	-	-	-	-	
MIDWEST ENERGY ASSOCIATION	4,360	-	-	-	-	-	
NORTHEASTERN PENNSYLVANIA ALLIANCE	1,655	-	-	-	-	-	
OUR NATIONS ENERGY FUTURE COALITION	12,500	-	-	-	-	-	
ALLENTOWN ECONOMIC DEVELOPMENT CORP.	5,000	-	-	-	-	-	
THE COALITION FOR RENEWABLE NATURAL GAS	20,400	-	-	-	-	-	
					-		
ORGANIZATIONS $1,500 & UNDER (IN CLAIM YEAR FY27):					-		
FOCUS CENTRAL PENNSYLVANIA - NORTH	3,000	1,500	1,500	-	1,500	1,500	
HBA OF METROPOLITAN HARRISBURG	655	1,488	6,498	5,000	-	1,498	
LANCASTER CHAMBER OF COMMERCE	1,100	1,200	1,236	-	1,236	1,250	
THE GREATER CARBONDALE CHAM OF COMMERCE	500	-	500	-	500	750	
SHIPPENSBURG AREA CHAMBER OF COMM	479	-	541	562	-	541	
WILLIAMSPORT/LYCOMING CHAM OF COMM	-	500	500	-	500	500	
DEVELOP TIOGA	500	500	500	-	500	500	
CARLISLE CHAMBER MEMBERSHIP	-	-	-	-	284	284	
Total	$ 1,231,432	$ 1,028,870	$ 1,549,906	$ 699,024	$ 831,384	$ 1,593,479	

* Excludes lobbying portion of dues.
** For the five month ending February 28, 2026
^ Reflects one quarter of annual membership cost for EE&C.

UGI UTILITIES, INC. - GAS DIVISION
EXPLANATION OF REQUEST I&E-RE-13 PART F

Organization Name	Explanation
American Gas Association	Provides industry safety standards, engineering codes, and federal regulatory advocacy (DOT/PHMSA compliance) governing pipeline design, operation, and maintenance. Ensures the utility meets or exceeds federal pipeline safety requirements, directly reducing the risk of incidents and service disruptions for customers.
Gas Technology Institute: Emerging Technology Program	Provides access to research related to customer energy efficiency.
Gas Technology Institute: Operations Technology Development (OTD)	Funds and provides access to research and development on pipeline integrity, leak detection, system efficiency, and infrastructure modernization technologies. Enables adoption of new technologies that improve reliability, reduce outages, and lower operating costs .
Energy Association of Pennsylvania	Focuses on creating a collaborative environment to support support sharing of utility best practives and to address customer affordability matters.
Northeast Gas Association	Provides a regional forum on pipeline capacity, winter peaking reliability, emergency mutual aid, and regulatory issues specific to the Northeastern U.S. market. Strengthens regional energy security and service reliability during peak demand periods, reducing the risk of supply interruptions for PA customers.
Economic Development of Lancaster	This membership supports UGI Gas's ability to monitor and respond to business growth and development trends throughout Lancaster County. Awareness of planned commercial and industrial expansion enables the Company to proactively plan distribution system investments necessary to serve new and growing load. Broader customer base spreads fixed infrastructure costs more widely, supporting long-term rate stability for all customers.
PA Chamber of Business and Industry	Provides a statewide business advocacy forum supporting sound energy and regulatory policy in Pennsylvania's legislative and regulatory environment. Promotes a stable policy environment that supports infrastructure investment, workforce development, and reliable energy supply for businesses and residents.
Energy Solutions Center	Promotes efficient end-use natural gas technologies through demonstrations and programs for commercial and industrial customers. Helps customers access cost-effective gas equipment and efficiency improvements, lowering energy bills and supporting economic competitiveness.
Lehigh Valley Economic Development Corp	Supports commercial and industrial development in the Lehigh Valley, driving new gas customer additions and strengthening regional economic activity. Growing the customer base in the Lehigh Valley improves system economics and supports infrastructure investment that benefits all customers in the region.
Greater Reading Economic Partnership	Drives economic development and business attraction in the Greater Reading area, supporting gas customer growth and system utilization. New customer additions in the Reading area improve cost allocation and support continued infrastructure investment serving existing customers.
Lebanon Valley Economic Development Corp	Supports business development and industrial recruitment in Lebanon Valley, growing the natural gas customer base in the service territory. Increased system utilization from new customers contributes to rate stability and long-term affordability for existing customers.
Wyoming Valley Chamber of Commerce	Connects the utility with the Wyoming Valley business community, supporting customer development and community relationships in Northeastern PA. Strengthens local economic activity and new customer growth, supporting the utility's ability to invest in safe, reliable infrastructure in the region.
Penn Northeast – Gas Division	Regional economic development organization focused on attracting industrial and commercial gas customers to Northeastern Pennsylvania. Industrial and commercial load additions improve system load factors and help support cost-effective service for residential and small commercial customers.
Bethlehem Economic Development Corp	Supports economic development and business attraction in the City of Bethlehem, driving new gas service connections and system growth. New business development in Bethlehem supports customer growth that contributes to rate base health and long-term rate stability.

UGI UTILITIES, INC. - GAS DIVISION
EXPLANATION OF REQUEST I&E-RE-13 PART F

Organization Name	Explanation
Scranton Chamber of Commerce	Connects the utility with the Scranton-area business community, supporting customer retention, new business attraction, and community relationships. Active engagement in Scranton supports economic growth and new gas customer additions in one of the utility's key northeastern service areas.
Wyoming County Chamber of Commerce	Provides a forum for engaging with Wyoming County businesses and community leaders, supporting local economic development and customer relations. Supports new customer opportunities and community goodwill in Wyoming County, reinforcing the utility's commitment to rural service territories.
Greater Susquehanna Chamber of Commerce	Engages with businesses and community stakeholders in the Susquehanna region, supporting economic development and gas service growth. Promotes local business development and new customer connections in the Susquehanna Valley service area.
Pipeline Association for Public Awareness	Dedicated to pipeline safety education for customers, excavators, municipalities, and first responders; supports PA 811 'Call Before You Dig' damage prevention programs. Reduces third-party pipeline damage — the leading cause of gas incidents — directly protecting public safety, property, and service continuity for all customers.
Harrisburg Regional Chamber & CREDC	Connects the utility to Central Pennsylvania's business and economic development community, supporting new customer growth and infrastructure investment advocacy. Supports commercial and industrial development in the Harrisburg region, growing the customer base and promoting long-term rate stability.
WEDCO – Wayne Economic Development Company	Supports economic development in Wayne County, attracting businesses and supporting new gas service connections in a rural service area. Business development in Wayne County supports new customer additions, helping spread infrastructure costs and maintain service in rural communities.
Focus Central Pennsylvania – North	Promotes business development and economic growth in Central Pennsylvania's northern counties, supporting gas customer additions in the service territory. New commercial and industrial connections in north-central PA support system growth and help maintain affordable service for existing customers.
HBA of Metropolitan Harrisburg	Home Builders Association engagement supports new residential construction and gas service connections throughout the greater Harrisburg market. New residential construction drives gas service extensions and customer additions, supporting infrastructure investment and long-term system sustainability.
Lancaster Chamber of Commerce	Provides engagement with Lancaster County's large and diverse business community, supporting customer development and community relationships. Strengthens the utility's relationships with one of its major service areas, supporting business
The Greater Carbondale Chamber of Commerce	Connects the utility with businesses and community leaders in the Carbondale area, supporting local economic development and customer relationships. Promotes new customer development and community engagement in the Carbondale service area of Northeastern Pennsylvania.
Shippensburg Area Chamber of Commerce	Supports business development and community engagement in the Shippensburg area, connecting the utility with local commercial customers. Supports new customer connections and community relations in Cumberland County, reinforcing the utility's presence in south-central PA.
Williamsport/Lycoming Chamber of Commerce	Engages with the business community in the Williamsport and Lycoming County area, a key portion of the utility's northcentral PA service territory. Promotes economic development and new gas customer additions in Lycoming County, supporting system growth and long-term customer affordability.
Develop Tioga	Economic development organization for Tioga County supporting business attraction and job creation in a rural area of the service territory. Supports new customer growth in Tioga County, helping to sustain infrastructure investment and reliable service in a rural portion of the service territory.
Carlisle Chamber Membership	Connects the utility with the Carlisle business community in Cumberland County, supporting commercial customer relationships and local economic development. Promotes new business development and customer growth in the Carlisle area, contributing to system utilization and rate base health.

UGI Gas Exhibit VKR-2R

UGI Utilities, Inc. - Gas Division
Pipeline Investment Grants

Project Name	Location	Grant Agency	Grant Name	Grant Recipient	Amount
In Process:					
Redacted	Hegins, PA	Pennsylvania - DCED	Pipeline Investment Program	Schuylkill Economic Development Corporation	$ 834,002
Redacted	Smithfield Township, PA	Pennsylvania - DCED	Pipeline Investment Program	Pocono Mountain Economic Development Corp.	338,174
Completed:					
Redacted	Selinsgrove, PA	Pennsylvania - DCED	Pipeline Investment Program	Susquehanna Industrial Development Corporation	471,902
Redacted	Bedford, PA	Pennsylvania - DCED	Pipeline Investment Program	Bedford County Development Association (BCDA)	100,000
Redacted	Dupont, PA	Pennsylvania - DCED	Pipeline Investment Program	Greater Wilkes-Barre Industrial Fund	1,499,557
Redacted	Stroud Township, PA	Pennsylvania - DCED	Pipeline Investment Program	Lehigh Valley Economic Investment Corp.	324,061
Redacted	Bethlehem Township, PA	Pennsylvania - DCED	Pipeline Investment Program	Lehigh Valley Economic Investment Corp.	249,229
Redacted	Cornwall, PA	Pennsylvania - DCED	Pipeline Investment Program	Lebanon Valley EDC	750,000
Redacted	Brady Twp., Lycoming County	Pennsylvania - DCED	Pipeline Investment Program	Lycoming County	287,379
Redacted	East Stroudsburg, PA	Pennsylvania - DCED	Pipeline Investment Program	Pocono Mountain Economic Development Corp.	231,110
Redacted	Waymart, PA	Pennsylvania - DCED	Pipeline Investment Program	Wayne Economic Development Company "WEDCO"	1,000,000
Redacted	Waymart, PA	Pennsylvania - DCED	Pipeline Investment Program	Wayne Economic Development Company "WEDCO"	376,392
Redacted	Tunkhannock, PA	Pennsylvania - DCED	Pipeline Investment Program	Wyoming County Chamber of Commerce	1,000,000
Redacted	Tunkhannock, PA	Pennsylvania - DCED	Pipeline Investment Program	Wyoming County Chamber of Commerce	1,000,000
					$ 8,461,806

UGI Gas Exhibit VKR-3R

UGI Utilities, Inc. - Gas Division
PUC Assessment Invoice Estimate vs. Actual - 2025
$s in thousands

	Invoice #		Amount		PUC Assessment Period Covered
2020 Invoice	20-123100	$	2,816		July 2020-June 2021
2021 Invoice	21-123100	$	3,515		July 2021-June 2022
2022 Invoice	22-123100	$	3,051		July 2022-June 2023
2023 Invoice	23-123100	$	3,523		July 2023-June 2024
2024 Invoice	24-123100	$	4,550		July 2024-June 2025
2025 Invoice	25-123100	$	4,551	A	July 2025-June 2026

OCA's Method - 3 Year Average

Invoice Year:	Invoice #:		Amount
2021 Invoice	21-123100	$	3,515
2022 Invoice	22-123100	$	3,051
2023 Invoice	23-123100	$	3,523

Invoice Year:			Estimate using 3 Year Average	
2025 Invoice	Estimate	$	3,363	B

Company's Method - Average Change

Invoice Year	Invoice #:		Amount	YoY Increase	% Change
2020 Invoice	20-123100	$	2,816		
2021 Invoice	21-123100	$	3,515	$ 699	24.8%
2022 Invoice	22-123100	$	3,051	$ (464)	-13.2%
2023 Invoice	23-123100	$	3,523	$ 472	15.5%
			3 Year Average Increase		9.0%

Invoice Year			Invoice Basis for Estimate	3 Year Average Change		Estimate Amount using 3 Year Average Change	
2024 Invoice	Estimate	$	3,523	9.0%	$	3,841	
2025 Invoice	Estimate	$	3,841	9.0%	$	4,188	C

Evaluation of Estimate for 2025 Invoice:

				Difference from Actual
Actual 2025 Invoice	$	4,551	A	
Estimate using OCA Method	$	3,363	B	$ (1,188)
Estimate using Company Method	$	4,188	C	$ (363)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 5-R

Rebuttal Testimony of
Amy M. Keller

Topics Addressed: Updates to Claim
Rate Base and Expense Adjustments
PUC Annual Report

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Amy M. Keller. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 5, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of the Pennsylvania Public Utility Commission's ("Commission" or "PUC") Bureau of Investigation and Enforcement ("I&E"), and the Office of Consumer Advocate ("OCA"). Specifically, I address: (1) the error identified by the Company wherein the amortization income of the over-recovery of post-retirement welfare plan expense was inadvertently included in the Company's claim; (2) the direct testimony of OCA Witness Rogers (OCA Statement No. 2) regarding OCA's recommended adjustment to the depreciation expense of UGI Utilities, Inc. ("UGI") and a corresponding adjustment to UGI's accumulated depreciation; and (3) the direct testimony of I&E Witness Walker (I&E Statement No. 1) regarding I&E's recommendation that UGI should produce separate UGI Gas and UGI Utilities, Inc. – Electric Division ("UGI Electric") annual reports submitted to the PUC.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring CONFIDENTIAL UGI Gas Exhibit AMK-1R and UGI Gas Exhibit AMK-2R.

II. UPDATES OR REVISIONS TO THE COMPANY'S CLAIM

Q. Before responding to the rebuttal of I&E and OCA, do you have any updates or revisions to the Company's claim?

A. Yes. In preparing the response to I&E-RE-29, which is attached hereto as CONFIDENTIAL UGI Gas Exhibit AMK-1R, the Company identified an error in its claim. The amortization of the regulatory liability for past over-recovery of post-retirement welfare plan expense will terminate at the end of the FTY (FY 2026). In the Company's claim, this amortization income was inadvertently included in the Company's claim for the FPFTY (FY 2027). Therefore, the Company is revising its claim to remove the $974,464 of amortization income.

Q. Please explain the impact of this revision to the Company's proposed revenue requirement in this matter.

A. Based on the information detailed above, the Company will reflect a downward adjustment of $974,464 as part of its updated claim in this case. This update is reflected in Schedule D-2 of UGI Gas Exhibit A – Fully Projected (REBUTTAL), which is sponsored by UGI Gas witness Tracy A. Hazenstab (UGI Gas St. No. 2-R).

III. RATE BASE ADJUSTMENTS

A. ACCUMULATED DEPRECIATION AND ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

Q. Do any of the other parties propose an adjustment to the Company's claim for accumulated depreciation and ADIT?

A. OCA Witness Rogers advances an adjustment to the Company's depreciation expense, and a corresponding adjustment to its accumulated depreciation, based upon the recommendations of OCA Witness Garren. OCA St. 2, at p. 7. OCA Witness Rogers also states that "if the Company is able to calculate the related ADIT adjustment" that is required as a result of the OCA's other adjustments, that she may update her recommendation in surrebuttal testimony. OCA St. 2, at p. 7.

Q. What is UGI Gas's response to OCA's proposals regarding accumulated depreciation and ADIT?

A. The Company's response to OCA's proposal to adjust the Company's depreciation expense is inextricably intertwined with the Company's rebuttal to the depreciation expense adjustment proposed by OCA witness Mr. Garren. In summary, OCA Witness Garren proposes to change the service life method utilized by the Company, as well as adjust the service lives used for three plant accounts, which reduces the Company's depreciation expense by $20.8 million. OCA St. 4, p. 6.[1] In OCA Witness Rogers Statement 2, page 7, she noted that she applied the depreciation recommendations per Witness Garren's testimony but yielded a decrease in depreciation expenses by $21.8 million. The Company disagrees with these proposed adjustments, for the reasons explained in the rebuttal testimony of UGI Gas witness John F. Wiedmayer (UGI Gas Statement No. 6-R).

However, if adopted, Witness Garren's proposed adjustment to depreciation expense necessarily requires related adjustments to accumulated depreciation and ADIT.

[1] I note that Mr. Garren recommends this adjustment based upon "data available as of September 30, 2026 plant balances used for the future test year, which is the period on which the service life analysis was conducted." OCA St. 4, p. 5. Ms. Rogers, however, applies this adjustment to the Company's fully projected future test year ending September 30, 2027 ("FPFTY") claim for depreciation expense. OCA St. 2, p. 7.

Importantly, Witness Garren did not make these associated and necessary adjustments to accumulated depreciation and ADIT, which results in a material understatement of OCA's proposed revenue requirement in this proceeding. As explained by Mr. Wiedmayer (UGI Gas Statement No. 6-R), Witness Garren's depreciation expense adjustment would be calculated for the entire life of the assets through September 30, 2027, to restate the accumulated depreciation reserve as if Witness Garren's proposed service life method was used consistently by the Company over the entire life of the assets. While it is impractical to do a detailed year-by-year recalculation of depreciation over the more than 40 years that the Company's existing method has been in place, the Company has performed a high-level calculation indicating that the related adjustment to accumulated depreciation would decrease accumulated depreciation by an estimated $257 million and, as a result, the Company's proposed rate base would increase by an estimated $245 million. I have included this calculation with my testimony as UGI Gas Exhibit AMK-2R, where the potential accumulated depreciation impacts are reflected on page 2. Also, the Company estimates that, at a high level, ADIT as of September 30, 2027, would increase by an estimated $37 million and, as a result, the Company's proposed rate base would decrease by an estimated $37 million. The potential ADIT impacts are reflected in UGI Gas Exhibit AMK-2R, on page 3 at a high-level as well.

Q. What would the revenue requirement impacts be from OCA's adjustments to accumulated depreciation and ADIT?

A. A $25 million revenue requirement increase would be needed to offset Witness Garren's proposed adjustment. *See* UGI Gas Exhibit AMK-2R, page 1.

Q. Are you proposing that the Commission adopt these adjustments to accumulated depreciation and ADIT?

A. No. These adjustments would only be required to calculate the revenue requirement if Witness Garren's proposal is accepted. I am supplying this information to: (1) demonstrate that Witness Garren's proposed depreciation adjustment is incomplete and, if adopted, requires associated accumulated depreciation and related ADIT adjustments that OCA has failed to consider; and (2) provide a calculation estimate for the overall impacts to revenue requirement of Witness Garren's proposal once properly reflected. Specifically, the $25 million revenue requirement increase would partially offset Witness Garren's proposed downward adjustment.

Accordingly, Witness Garren's adjustment cannot be considered as complete as he has presented it and it must either be rejected or be corrected/completed. However, to be clear, the Company opposes Witness Garren's proposal that it utilize the Average Life Group ("ALG") method, his proposal to increase the service lives of assets in specific plant accounts, and his proposed adjustment to depreciation expense. Therefore, no adjustment to depreciation expense or any resulting adjustment to accumulated depreciation and/or ADIT should be adopted.

IV. PUC ANNUAL REPORT DATA

Q. Please summarize the testimony of I&E Witness Walker regarding the data UGI supplies to the PUC as a part of its annual reports.

A. I&E Witness Walker testifies that UGI should be able to produce separate gas and electric data in its PUC annual reports, and argues that how this data is currently presented is

"misleading." I&E St. No. 1, at pp. 6-8. He contends that as UGI was able to break down utility plant and related items between gas and electric operations, it stands to reason that other balance sheet accounts could be broken down at a similar level and if not, UGI should still be required to provide a breakdown of the plant-related items that it already breaks down for FERC. He further takes issue with the Company's explanation in discovery that it would need to petition the PUC for approval to provide this data separately for UGI Gas and UGI Electric.

Q. Before responding to I&E Witness Walker, can you clarify and explain how UGI develops and submits data to the PUC for purposes of its annual reports?

A. Yes. For the Annual Report filed with the PUC for the year ending December 31, 2024, the vast majority of required schedules are prepared reflecting solely UGI Gas data. This includes operating revenues, operating expenses, plant in service, depreciation, customer statistics, and all other operational and income statement-related schedules. These schedules are prepared on a UGI Gas-only basis because the underlying data is tracked, recorded, and maintained separately for UGI Gas in the ordinary course of business.

However, four sets of pages are prepared using the consolidated UGI balance sheet information rather than gas-only data:

- Page 200 — Comparative Balance Sheet (Assets and Liabilities)
- Page 213 — Accounts Receivable/Payable from/to Associated Companies
- Page 216 — Unamortized Debt Discount and Premium on Debt
- Page 231 — Long Term Debt

These pages reflect balance sheet items that exist at the legal entity level — i.e., they exist for UGI Utilities, Inc. as a whole — and cannot be meaningfully disaggregated between UGI Gas and UGI Electric operations. What this means is that this information is not divisional in nature. No gas-only balance sheet exists as an audited financial document.

It is worth noting that the Unamortized Debt Discount on Page 216 and the Interest for the Year on Page 231 are allocated between UGI Gas and UGI Electric operations. It is only the outstanding debt balances — which are obligations of the legal entity and cannot be attributed to a division — that are presented at the consolidated level.

I&E Witness Walker points to UGI Electric's FERC Form 1 dated December 31, 2023, specifically the summary of utility plant and accumulated provisions for depreciation, amortization, and depletion, as evidence that the Company is capable of separating gas and electric data for balance sheet purposes. This observation, while accurate in the narrow context of utility plant, does not support a broader conclusion that all balance sheet items can be similarly disaggregated. Utility plant accounts outside of common plant assets, are inherently gas or electric in nature — a gas main is a gas asset and a power line is an electric asset — and the Company already presents this data on a separated basis in the PUC Annual Report on Pages 205 and 205.1 (Utility Plant in Service), Pages 206 and 207 (Accumulated Depreciation of Utility Plant), and Page 208 (Construction Work in Progress). The ability to separate physical plant assets by division does not extend to financial items such as cash, long-term debt, deferred income taxes, and equity, which are maintained at the legal entity level and have no inherent gas or electric character.

Q. Does UGI Gas agree with I&E's recommendation that it submit this data separately?

A. No, it does not.

Q. Why not?

A. The Annual Report schedules that are currently presented on a consolidated basis reflect balance sheet items that exist at the legal entity level of UGI. The recommendation to separate this data presupposes that a reliable, accurate, and verifiable gas-only balance sheet can be produced. It cannot.

I&E's recommendation fails to recognize the two distinct categories of data presented in the Annual Report. As I noted in my prior response, non-common utility plant assets and related items — such as gas mains, meters, and electric distribution facilities — are inherently divisional in character and are already presented on a separated basis in the Annual Report. The Company has no objection to, and already complies with, separate reporting for those items. The balance sheet items identified by I&E in this case are categorically different.

In summary, the consolidated balance sheet data currently used for these schedules is derived directly from UGI's audited financial statements. It is objectively verifiable, consistent year over year, and subject to independent audit. A divided balance sheet produced in the manner recommended by I&E would have none of these qualities. As such, while I&E's recommendation appears to be offered for the purpose of increasing precision and transparency, it would only produce the **appearance** of additional precision and transparency but would be based on information that is not independently verified by audit and could vary depending on assumptions made in any given year.

V. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit AMK-1R
(No Public Version Available)

UGI Gas Exhibit AMK-2R

UGI Utilities, Inc. - Gas Division
Estimated Impact of Accumulated Depreciation and ADIT Adjustments on Revenue Requirement
Fully Projected Future Test Year (Fiscal 2027)
$s in '000s

A	Accumulated Depreciation Adjustment (1982 - Present)	$	256,528	see page 2
B	ADIT Adjustment (1982 - Present)	$	(37,220)	see page 3
A+B=C	Cumulative Adjustment to Rate Base (1982 - Present)	$	219,308	
D	As-Filed Rate of Return		8.20%	Exhibit A, Fully Projected, Schedule A-1, line 21
C*D=E	Incremental Earnings on Cumulative Adjustment to Rate Base (1982 - Present)	$	17,983	
F	Gross Revenue Conversion Factor		1.392298	Exhibit A, Fully Projected, Schedule A-1, line 24
E*F	Impact to Revenue Requirement	$	25,038	

Note: Calculation prepared for illustrative purposes and does not include income tax or cash working capital impacts.

UGI Utilities, Inc. - Gas Division
Estimated Accumulated Depreciation Adjustment
Fully Projected Future Test Year (Fiscal 2027)
$s in '000s

A	FTY (2026) OCA Depreciation Expense Adjustment	$	(21,800)	OCA St. No. 2 (Rogers), Schedule JLR-5
B	FTY (2026) UGI Gas (Wiedmeyer) Depreciation Expense	$	140,600	OCA St. No. 4 (Garren), Table JSG-1, page 6
A/B=C	Percentage Difference - OCA vs. UGI Gas Accruals		-15.5050%	
	9/30/2026 UGI Gas Accumulated Depreciation Book Reserve for Total			
D	Depreciable Gas Plant - Cumulative Impact	$	1,503,820	UGI Gas Exhibit C (Future), Book VII, page V-7, column 9
D*C=E	Estimated Overstatement of FTY (2026) UGI Gas Book Reserve	$	(233,167)	
F	FPFTY (2027) UGI Gas (Wiedmeyer) Depreciation Expense	$	150,666	UGI Gas Exhibit C (Fully Projected), Book VI, page II-4, column 8
F*C=G	Estimated Overstatement of FPFTY (2027) UGI Gas Depreciation Expense	$	(23,361)	
E+G	Estimated Cumulative Overstatement of FPFTY (2027) UGI Gas Book Reserve	$	(256,528)	

Note: Adjustments are related to depreciable gas plant, and exclude common plant.

UGI Utilities, Inc. - Gas Division
Estimated Accumulated Deferred Income Taxes ("ADIT") Adjustment
Fully Projected Future Test Year (Fiscal 2027)
$s in '000s

A	UGI Gas FPFTY (2027) Accumulated Deferred Income Taxes ("ADIT")	$	(716,793)	Exhibit A, Fully Projected, Schedule A-1, line 6
B	UGI Gas FPFTY (2027) Net Plant in Service	$	4,940,513	Exhibit A, Fully Projected, Schedule A-1, line 3
A/B=C	ADIT as Percentage of Net Plant in Service		-14.5085%	
D	Estimated Cumulative Overstatement of FPFTY (2027) UGI Gas Book Reserve	$	256,528	see Page 2
B+D=E	Estimated UGI Gas FPFTY (2027) Net Plant in Service, Adjusted	$	5,197,041	
E*C=F	UGI Gas FPFTY (2027) Accumulated Deferred Income Taxes ("ADIT"), Adjusted	$	(754,013)	
A-F	Estimated Cumulative Understatement of FPFTY (2027) UGI Gas ADIT	$	37,220	

UGI Gas Exhibit AMK-2R

UGI Utilities, Inc. - Gas Division
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Fully Projected Future Test Year (Fiscal 2027)
$s in '000s

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Note: Calculation prepared for illustrative purposes and does not include income tax or cash working capital impacts.

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Note: Adjustments are related to depreciable gas plant, and exclude common plant.

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A-F	Estimated Cumulative Understatement of FPFTY (2027) UGI Gas ADIT	$	37,220	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3059523, et al.
UGI Utilities, Inc. – Gas Division	)	

UGI GAS STATEMENT No. 6-R

REBUTTAL TESTIMONY OF
JOHN F. WIEDMAYER
ON BEHALF OF
UGI UTILITIES, INC. – GAS DIVISION

May 13, 2026

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. ARE YOU THE SAME JOHN WIEDMAYER THAT PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the depreciation-related testimony of James S. Garren on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). Mr. Garren has proposed the use of the Average Life Group ("ALG") procedure to calculate depreciation expense and depreciation annual accrual rates. He also proposes alternative survivor curve estimates for Account 375, Structures and Improvements; Account 376.1, Mains – Primarily Steel; and Account 378, Measuring and Regulating Station Equipment, General. My testimony will respond to these positions.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL TESTIMONY?

A. Yes, I am sponsoring UGI Gas Exhibits JFW-1R and JFW-2R.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Mr. Garren has proposed a reduction in depreciation expense of $20.8 million[1] (as of the future test year) in a manner that contradicts 44 years of Pennsylvania Public Utility Commission ("Commission" or "PUC") precedent approving use of the equal life group ("ELG") depreciation procedure for rate making purposes. UGI Utilities, Inc. – Gas Division ("UGI Gas" or "Company") has utilized the same Commission-approved process for developing depreciation rates and expense for the past 44 years. UGI Gas uses the ELG procedure for vintages 1982 and subsequent instead of the Average Life Group ("ALG") procedure. The Average Life Group procedure is most commonly identified in Pennsylvania as the Average Service Life ("ASL") procedure. The use of the ELG procedure was established with the Pennsylvania Utilities Commission ("PUC") in 1982 and has been used by most gas utilities in Pennsylvania to calculate depreciation expense and annual depreciation accrual rates since that time spanning a period of approximately 44 years.

In my testimony, I will address the following topics. First, I will address the ELG vs ALG calculations. Second, I will discuss the history of ELG and its precedent in Pennsylvania. Third, I will explain how ELG is more equitable for current and future customers. Fourth, I will address the errors in OCA Witness Garren's depreciation calculations related to his proposing an ALG procedure but using depreciation reserve balances that are based on historic and projected accruals using the ELG procedure. Fifth, I will address Mr. Garren's incorrect use of the balances at September 30, 2026, the end of

[1] Mr. Garren calculated depreciation as of the future test year based on his claim that Sep 2026 "is the period on which the service life analysis was conducted." OCA St. 4, at p. 5. This claim is incorrect. The service life analysis was conducted using accounting data through September 30, 2022, and the Company's primary proposed rates are based on the fully projected future test year of Sep 2027.

the future test year, rather than at September 30, 2027, as the basis for calculating his depreciation expense claim. And lastly, I will address Mr. Garren's alternative service life proposals.

A. Equal Life Group vs. Average Life Group

Q. WHAT IS THE EQUAL LIFE GROUP PROCEDURE?

A. For the ELG procedure, a group of property listed by vintage (e.g., a group of meters installed within the same fiscal year) is subdivided into groups having equal service lives. The size of these "equal life groups" is based on the estimated survivor characteristics of the account. For example, UGI replaces 15,000 to 20,000 meters per year. Some of these meters will experience a service life of 1 year, some 2 years, some will experience the maximum expected life of 66 years, and some will experience lives between 2 and 66 years. Depreciation can then be calculated for each equal life group based on the straight line method, meaning that an equal amount of the group's service value is recorded as depreciation expense in each year of service. The total depreciation for an account is then the summation of the calculated depreciation for each equal life group. The ELG depreciation calculation procedure mathematically estimates the life for each unit in the account and then depreciates each unit over its expected life based on the survivor curve estimate for an account. The ELG procedure is also known as the *Unit Summation* Procedure.

Q. HOW DOES THE ELG PROCEDURE DIFFER FROM THE AVERAGE SERVICE LIFE ("ASL," ALSO REFERRED TO AS "AVERAGE LIFE GROUP," OR "ALG") PROCEDURE?

While the ELG procedure calculates depreciation for each equal life group, the ASL (or ALG) procedure depreciates every asset within an account over the average life of the entire account. Using equal life groups, rather than an average life, as the basis for depreciation provides a more precise calculation that better matches capital recovery with consumption of the assets's service value by depreciating assets that have shorter lives than the average, over their shorter lives (and the longer-lived assets over their longer lives) as opposed to depreciating all assets over a single average life for the group.

Q. IS ELG SUPPORTED BY DEPRECIATION AUTHORITIES?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. For example, Robley Winfrey, who developed the Iowa survivor curves at Iowa State University and is regarded as a pioneer of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[2]

Depreciation Systems by Wolf and Fitch, also supports the appropriateness of ELG stating, "Application of the equal life group procedure is generally considered to better match the consumption of capital with service provided than does application of the average life procedure."[3]

Q. IS MR. GARREN'S ASSERTION THAT THE "ELG METHOD IS A FORM OF ACCELERATED DEPRECIATION" CORRECT?

A. No. Mr. Garren's characterization is incorrect. The ELG method uses a straight-line approach to allocate cost over the service life of a group of assets based on expected retirements. It does not accelerate depreciation like known accelerated methods do, such

[2] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71.
[3] Frank K. Wolf and W. Chester Fitch, *Depreciation Systems* (Ames, IA: Iowa State University Press, 1994); p.75.

as sum-of-the-years' digits or declining balance methods. Instead, it provides a systematic, rational allocation of cost that matches asset usage and retirements over time using the straight-line method. The depreciation rate for each equal life group is simply determined by the following equation: *Depreciation Rate = [1 / (Life of the Equal Life Group)].* So, the depreciation rate for an equal life group with a one-year life is 100%, 50% for a 2 year equal life group, 33.33% for a 3 year equal life group, and so on, until the maximum life of the survivor curve is reached. As we will see later in the testimony related to retirement frequency curves, the maximum life expectancy for a 45-R2 survivor curve, which is the estimate for Account 380, Services, is 84 years and a 1.19% (i.e., 1/84) rate. All accruals determined from the equal life groups are summed and their group's relative weighting determined mathematically from the survivor curve to develop a composite depreciation rate for each vintage and account.

Q. PLEASE EXPLAIN HOW DEPRECIATION IS DETERMINED USING THE ELG PROCEDURE.

A. A simple two-unit example will demonstrate how the ELG procedure more appropriately matches cost recovery to consumption than the ASL procedure. In this example, each unit costs $1,000. Unit A will be in service for 5 years, and unit B will be in service for 15 years. There is no net salvage for these units.

For the ASL procedure, the average service life for the two units is 10 years ([5+15]/2), so the annual depreciation rate is 10% (1/10) throughout the lives of both units. For the first five years, the total annual depreciation amount is $200 ($2,000 x 10%). At the end of year 5, the total annual accruals for the account are $1,000 ($200 x 5). Unit A is then retired, which results in a reduction in the accumulated depreciation of $1,000. At

the start of year 6, Unit B remains in service with an accumulated depreciation balance of $0. At this point, one-third of Unit B's service life has expired, and $1,000, an amount equal to its full original cost, must still be recovered through future depreciation accruals.

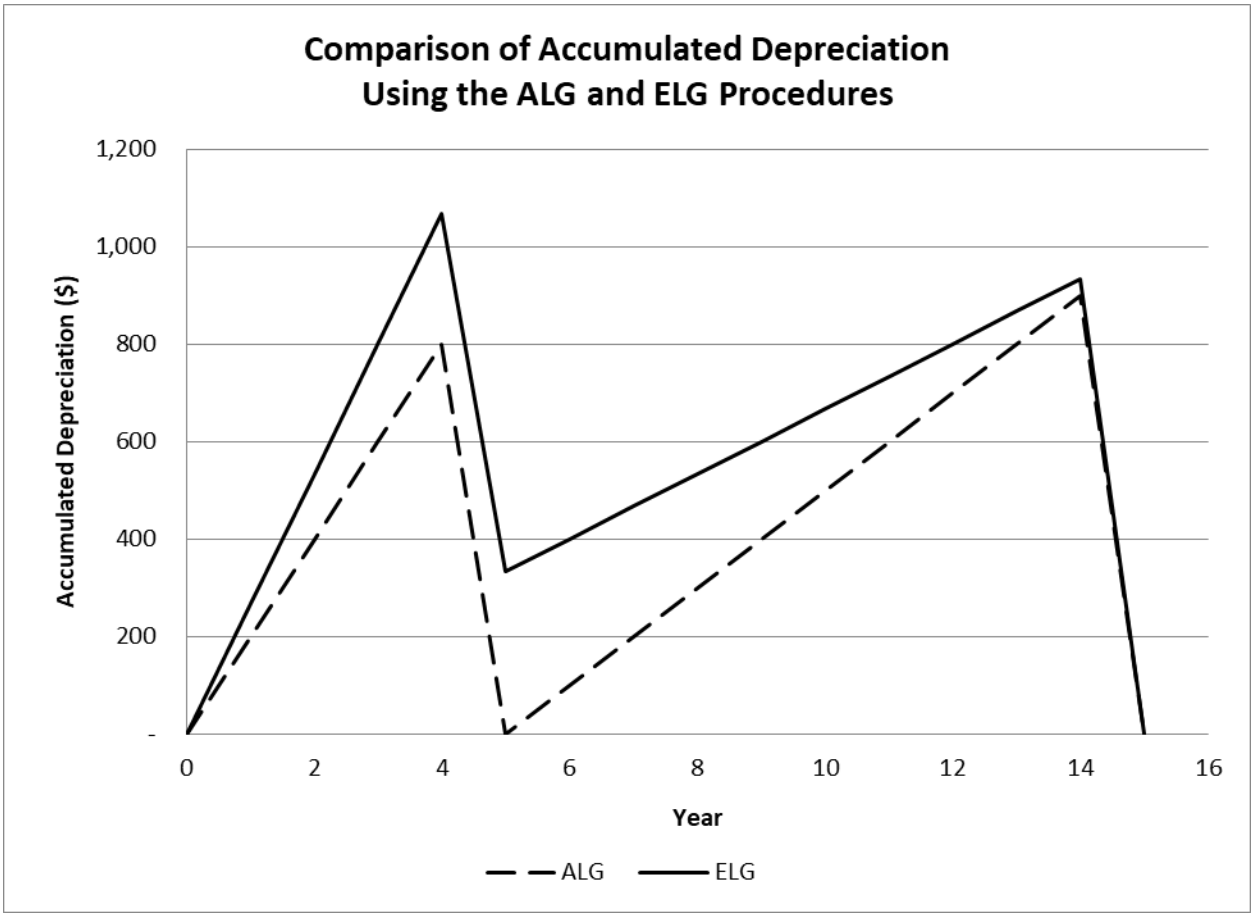
For the remaining 10 years, $100 ($1,000 x 10%) of annual expense is accumulated in depreciation, for a total of $1,000 when Unit B is retired at age 15. Thus, at the time of Unit B's retirement, the Company will have fully recovered the total depreciable cost of both units. However, at the end of year five, only one unit remained in service with two-thirds of its life expectancy left but with 100% of that unit's original investment still to be recovered. As a result, the ASL procedure is ineffective in matching cost recovery to the actual consumption of the asset. This is a characteristic deficiency of the ASL procedure.

When depreciation is determined using the ELG procedure, the pattern of cost recovery better matches actual consumption. Using the same two-unit example, the annual depreciation expense under the ELG procedure is calculated by summing the annual expense for each equal life group. In this case, there are two equal life groups – one for Unit A, which has a life of 5 years, and one for Unit B, which has a life of 15 years. The annual depreciation rate for Unit A is 20% (1/5) and for Unit B is 6.67% (1/15). Thus, the annual accruals for years 1 through 5 will be $200 ($1,000 x 20%) for the first equal life group (Unit A) summed with $66.67 ($1,000 x 6.67%) for the second (Unit B), or $266.67 in total. At the end of year 5, when Unit A is retired, the total accruals would be $1,333.33 ($266.67 x 5). The retirement of Unit A results in a reduction of $1,000 in accumulated depreciation, and at the start of year 6, the $1,000 original cost of Unit B remains with $333.33 in accumulated depreciation. Thus, with one-third of Unit B's life consumed, accumulated depreciation is exactly one-third of the original cost for this unit.

In the years 6 through 15, the annual depreciation expense is $66.67 for a total of $666.67 over the 10-year period. After the retirement of Unit B, the accumulated depreciation is $0 ($1,000 of accruals less the $1,000 retirement of Unit B), and the full recovery of both units has been obtained.

As this example shows, the ELG procedure better matches the cost recovery of both units with their actual service lives. Figure 1 below provides a graph of the accumulated depreciation for both procedures. The end of year 5 provides the best illustration of the difference between the two procedures. Under the ELG procedure, Unit A is fully recovered when retired at the end of year 5; Unit B is one-third through its service life and has had one-third of its cost recovered. This contrasts with the ASL procedure, in which accumulated depreciation is $0 at the end of year 5, even though the only unit remaining in service has consumed one-third of its service life. Clearly, the ELG procedure provides a better match regarding the consumption of the service value for the two units. Additionally, rate base under ELG at the end of year 5 is $667 (=$1,000-$333) versus $1,000 (=$1,000 - $0) under ASL. This example illustrates that in order for the rate base to be correct, annual depreciation needs to be correct (which it is using the ELG model). This example illustrates why Professor Robley Winfrey stated that the equal life group procedure was "the only mathematically correct procedure."

Figure 1. Comparison of Accumulated Depreciation Using the ALG and ELG Procedures



See below for the accounting entries that support Figure 1:

ACCUMULATED PROVISION FOR DEPRECIATION (ALG)				
Year	Entry	Debit	Credit	Balance
1	Accrual		200	200
2	Accrual		200	400
3	Accrual		200	600
4	Accrual		200	800
5	Accrual		200	1000
5	Retirement	1,000		**0**
6	Accrual		100	100
7	Accrual		100	200
8 thru 14	Accruals		700	900
15	Accrual		100	1,000
15	Retirement	1,000		0

ACCUMULATED PROVISION FOR DEPRECIATION (ELG)				
Year	Entry	Debit	Credit	Balance
1	Accrual		267	267
2	Accrual		266	533
3	Accrual		267	800
4	Accrual		267	1067
5	Accrual		266	1333
5	Retirement	1,000		**333**
6	Accrual		67	400
7	Accrual		67	467
8 thru 14	Accruals		466	933
15	Accrual		67	1,000
15	Retirement	1,000		0

Q. YOU HAVE PROVIDED A SIMPLE TWO-UNIT EXAMPLE DEMONSTRATING HOW ELG WORKS. DO THE SAME PRINCIPLES APPLY TO LARGER PROPERTY GROUPS WITH MANY UNITS?

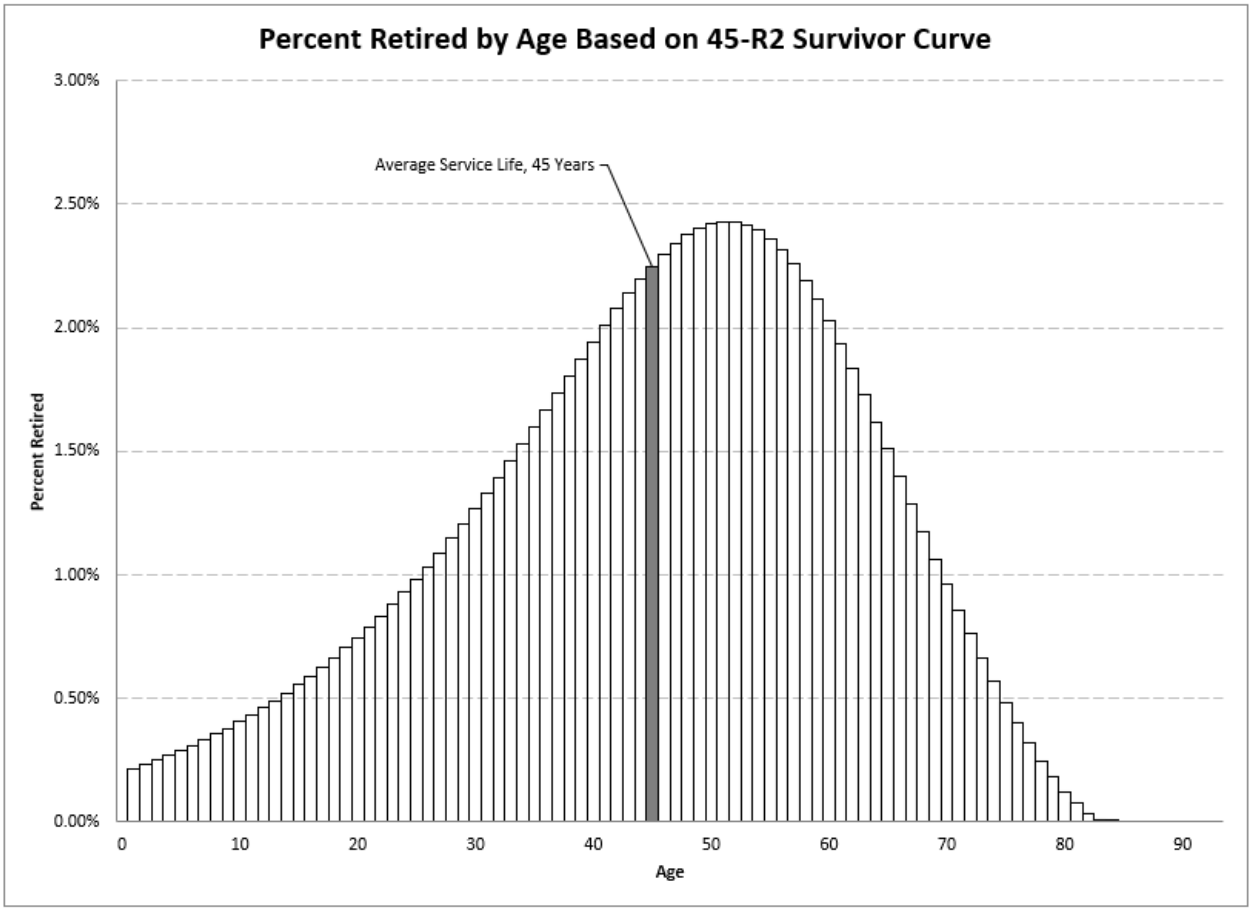
A. Yes. The same principles apply when the ELG procedure is applied to a large group of property with many units, as is typical of utility property. The survivor curve estimated for each property account can be used to divide an account into equal life groups. The

survivor curve allows for the calculation of the percentage of the property account that is in each equal life group, which allows for the calculation of ELG annual depreciation accruals for the entire property group. Under the ASL procedure, the depreciation expense for all property in the account is calculated based on the average service life for the entire group.

The ELG procedure recognizes that even homogenous utility plant, such as meters, will experience a range of service lives. This range of service lives is known as dispersion, which can be modelled using one of the 22 different Iowa curve types. Specifically, it recognizes that only an exceedingly small percentage of the account will be retired at the average service life in actual utility operations. Figure 2 listed below is a chart of the retirement frequency curve (a.k.a., frequency curve) for the 45-R2 survivor curve which will be used to illustrate a frequency curve. The frequency curve shows the percentage of property in this account that will be retired at each age, based on the estimated survivor curve. This percentage is also the size of each equal life group. The shaded bar in Figure 2 represents the percentage of property that will have a life of 45 years. In other words, this shows the percentage of property that is expected to be in service for the average service life. Only 2.25% of the assets will be in service for exactly 45 years. In contrast, a majority, 97.75%, of the assets will have a service life different than 45 years. All groups of assets within an account experience a range of service lives, known as dispersion. This dispersion is represented by distinct types of Iowa curves, e.g., L, S, R and O type Iowa curves. The ELG model is particularly well-suited to address the range of service lives resulting from this dispersion. For example, in the case of Account 380, Services, retirements can occur at any age due to random causes such as third-party damage, or more

systematically due to aging-related deterioration—especially in steel service lines. These examples conceptually reinforce how the frequency curve reflects a blend of unpredictable and age-related retirement causes.

Figure 2. Percent Retired by Age Based on 45-R2 Survivor Curve



The ELG procedure recognizes this dispersion and allocates costs for each equal life group over the expected life for that group. The service lives indicated by the 45-R2 survivor curves range from 1 year to 84 years. As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. Conversely, the ASL procedure depreciates every unit of property within an account over the same life, that is, the account's average life. The average service life for Account

380, Services is 45 years. As Figure 2 shows, this average life will be incorrect most of the time – in this example, the average life will be the wrong life for 97.75% of the assets.

Just as in the case for the two-unit example provided above, the ELG procedure better matches capital recovery with the actual lives forecast by the estimated survivor curve. Consequently, rate base will be higher when the ALG procedure is utilized because of the poor matching of recovery to utilization of the assets. That is, under the ALG procedure, the over-recovery on the long-lived assets is designed to make up for the under-recovery related to the short-lived assets relative to average service life as we have illustrated in the two unit example. This is not the case under ELG.

Q. ON PAGE 26 OF HIS DIRECT TESTIMONY, MR. GARREN ARGUES THAT "THE ASL PROCEDURE BETTER FITS THE ACTUAL ONGOING INVESTMENT AND RETIREMENT PATTERNS OF UTILITY PLANT OVERALL." OCA ST. 4, AT P. 26. DO YOU AGREE?

A. No. Mr. Garren mischaracterizes ELG as an accelerated method when it is simply a depreciation system that more accurately reflects the actual retirement patterns of assets. The depreciation system is a combination of selected depreciation methods, procedures and techniques used consistently by UGI Gas since 1982. The terms depreciation methods, procedures and techniques are industry terms used in depreciation parlance that have distinct meaning. Specifically, UGI Gas uses the straight-line method, equal life group procedure used in connection with the remaining life technique (SL-ELG-RL) for plant additions made 1982 and subsequent. UGI uses the Average Life Group (SL-ALG-RL) for additions made 1981 and prior.

In PA, nearly all investor-owned gas utilities use the ELG procedure. In fact, telephone companies in Pennsylvania were the first companies to adopt the ELG procedure in 1981 during the period in which they were rate-regulated and submitted depreciation studies to both the Federal Communications Commission (FCC) and PA PUC. The electric and gas companies in PA followed shortly thereafter in 1982 in adopting the ELG procedure including UGI. The water and wastewater companies followed after the energy companies using the ELG procedure in PA.

B. Pennsylvania Precedent

Q. IS THE ELG PROCEDURE SUPPORTED BY OTHER DEPRECIATION AUTHORITIES?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. As noted previously, Robley Winfrey, who developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data, referred to the ELG procedure as "the only mathematically correct procedure." [4]

Q. ARE OTHER COMMISSIONS STARTING TO IMPLEMENT THE ELG PROCEDURE GIVEN THE CURRENT REGULATORY ENVIRONMENT?

A. Yes. The ELG procedure is being utilized for utility assets by the Texas Railroad Commission. It is also has been used for many years in Canada, in jurisdictions such as Alberta, Nova Scotia and Newfoundland and Labrador and in other provinces more recently. The FCC first adopted ELG in the U.S. in early 1980s in the context of rapid technological change in the telecommunications industry at that time.[5]

[4] Robley Winfrey, Depreciation of Group Properties, Bulletin 155, p. 71.
[5] *See* Public Utility Depreciation Practices, NARUC, 1996, pp. 172-175.

Utility clients of GFT in Oregon, Alabama, Indiana, Louisiana, and Arkansas have been approved to use ELG. ELG has also been adopted recently in Colorado in response to significant technological and regulatory changes facing the gas industry.[6] New York is also considering ELG for similar reasons in an active case in New York.[7]

Q. HAS THE ELG PROCEDURE BEEN PREVIOUSLY ADOPTED IN PENNSYLVANIA?

A. Yes. ELG is the predominant method used in Pennsylvania and has been for many years. Most Pennsylvania gas utilities have used the ELG procedure since the early 1980s. ELG was adopted for UGI Gas in 1982 and has been used for depreciation since this approval.[8] Generally, every five years beginning in the mid-1980s, the Company has filed a service life study report with the Commission for approval based on Commission regulations. In 2023, UGI – Gas submitted its most recent five-year service life study report to the Commission and all depreciation parameters and methods, including the use of the Equal Life Group procedure, were approved. In the prior rate case, Docket No. R-2024-3052716, the ELG procedure was approved as a part of a Commission-approved settlement. Additionally, UGI Gas submits annual depreciation reports to the Commission each year updating its depreciation accrual rates for book purposes as well as identifying the underlying depreciation parameters and calculation methods and procedures used to determine depreciation expense. Under the Commission's regulation 52 Pa. Code §73.9(c), once such depreciation reports are filed and accepted "*[i]n subsequent*

[6] Decision No. C22-0642 in Proceeding No. 22AL-0046G p. 51, ¶¶ 161-163.
[7] New York State Department of Public Service Cases 24-E-0322 and 24-G-0323.
[8] Docket No. R-211899. ELG was adopted for many Pennsylvania utilities on a go-forward basis. For this reason, vintages of plant subsequent to the adoption of ELG use ELG while older vintages use ASL. For UGI, vintages 1982 and subsequent use ELG and vintages 1981 and prior use ASL.

ratemaking proceedings, the most recent annual depreciation report or service life study approved or deemed approved for accounting purposes only under this chapter, constitutes a rebuttable presumption as to the reasonableness of the accrued depreciation claimed for ratemaking purposes, and the burden of proving the unreasonableness of the accrued depreciation shall be on the challenging party." In 2023, the Company's five-year service life study report was deemed appropriate and approved by the Commission.

Q. ARE THE COMPANY'S CURRENT DEPRECIATION RATES BASED ON THE ELG PROCEDURE?

A. Yes. The Company's most recent annual depreciation report was filed on March 31, 2026 and most recent service life study was filed May 30, 2023. Both were based on the ELG procedure. The Annual Depreciation Report (ADR) submitted by UGI Gas to the Commission on March 31, 2026 is under review pending approval and is based on ELG. UGI Gas's most recently approved ADR was submitted on March 31, 2025, and it contains the depreciation rates the Company is currently using for book purposes based on the ELG procedure. All prior service life studies and ADRs submitted by UGI Gas since the mid-1980's have been approved using the ELG procedure. The ELG procedure was also adopted in UGI Gas's most recent rate case, Docket No. R-2024-3052716 as a part of a Commission-approved settlement.

Q. SINCE THE USE OF ELG IS THE PREDOMINANT AND LONGSTANDING PRACTICE IN PENNSYLVANIA, HAS MR. GARREN PROVIDED EVIDENCE FOR WHY THE COMPANY SHOULD DEVIATE FROM THIS PRACTICE?

A. No. Mr. Garren has not provided constructive evidence to support his claim that the ALG method is more appropriate than ELG. None of Mr. Garren's arguments support

overturning longstanding precedent despite having the burden of doing so under 52 Pa. Code §73.9(c). He appears to disagree with ELG simply because it can produce higher depreciation rates (relative to ALG) in assets' early years, consistent with the assets' mortality characteristics, but he provides no principled reason nor evidence for why lower depreciation rates resulting from the use of the average service life procedure are more appropriate.

He has provided minimal justification to support his claim that the Company's approved depreciation rates or calculation procedures, which are based on longstanding precedent, are unreasonable. Further, Mr. Garren ignores the issue of precedent for UGI, in effect only arguing that his proposal should be adopted because it results in lower depreciation expense and a short term reduction in rates for current customers.

However, as I will explain, Mr. Garren is incorrect that the longstanding use of ELG costs customers more than ASL would[9]. In fact, the opposite is true. Current customers benefit from the continued use of ELG, because rate base is much lower today than had ASL been used since 1982. The more precise recovery through ELG benefits customers over time because shorter-lived assets are correctly recovered over their useful lives, resulting in a lower rate base and lower return on rate base that exceeds the higher annual depreciation expense related to ELG. Further, the alleged benefit proposed by Mr. Garren, of lower short-term depreciation rates, is the result of the *change* in procedure, not from the procedure itself. Over time, the ASL depreciation rates will result in a higher rate base, and higher overall cost to customers.

[9] OCA St. No. 4, at p. 25.

C. Depreciation and Rate Base

Q. HOW DOES MR. GARREN DISCUSS THE IMPACT OF ELG ON CUSTOMER RATES?

A. Mr. Garren posits that the result of ELG is higher depreciation rates, which he argues is not in the best interest of ratepayers. However, as discussed above, not only does Mr. Garren ignore the impact of depreciation expense on rate base, but he fails to note that any benefit to current customers of his proposal to use ASL depreciation rates only results from the change from ELG to ASL – not from the overall use of the ASL procedure itself.

Q. PLEASE EXPLAIN THIS CONCEPT FURTHER.

A. Depreciation impacts customer rates in two ways. Depreciation expense is a direct component of the revenue requirement; however, accumulated depreciation[10] is also a *reduction* to rate base. A higher level of accumulated depreciation results in a lower rate base, a lower return on rate base and, therefore, lower customer rates when compared to a lower level of accumulated depreciation if the ALG procedure were used throughout the Company's history.

Therefore, higher depreciation expense will, over time, result in higher accumulated depreciation. Because average depreciation rates for a utility are typically in the 2% to 3% range and the return on rate base is higher (typically 7% to 8% or more), higher depreciation expense tends to produce lower customer rates over time.

Mr. Garren is aware of the dual nature of depreciation as it impacts revenue requirement and customer rates as described above. However, his recommendation, for

[10] Accumulated depreciation is the depreciation expense recorded to date including negative net salvage amortization, less recorded retirements and cost of removal, plus recorded gross salvage.

UGI Gas to switch depreciation calculation procedures from ELG to ALG, since its results in $20.8M less in annual depreciation (as of the future test year), without making a pro forma adjustment to *accumulated depreciation,* is one-sided and misleading. Every dollar reduction in annual depreciation will result in a corresponding increase in rate base in the first year and increasing amounts all subsequent years. That is, a $20.8M reduction in 2026 will result in a $20.8M increase in rate base in 2027, $41.6M in 2028, $63.4M in 2029 and so on. After 10 years, future rate base will be approximately $208M higher in this example using simplifying assumptions. Note, UGI has been using the ELG procedure for over 40 years. If UGI Gas had used ALG for the past 44 years instead of ELG, accumulated depreciation would have been much lower today and rate base, correspondingly, much higher today.

The longstanding use of ELG depreciation rates for Pennsylvania utilities has resulted in a lower rate base than if ALG had been used. Customers today pay lower customer rates than if ASL had been used during the years since ELG's adoption. As a result, it has been in customers' interest, not only to use ELG but also to use it consistently.

Over time ALG will result in higher customer rates than ELG. It is correct to assume that if the Company were to switch from ELG to ALG there would be a *short*-term decrease in expenses for current customers. However, this is not because ALG is in customers' best interest in the long term, but only because current customers would benefit from both lower ALG depreciation rates and amounts, and from the lower rate base that exists due to the longstanding use of ELG.

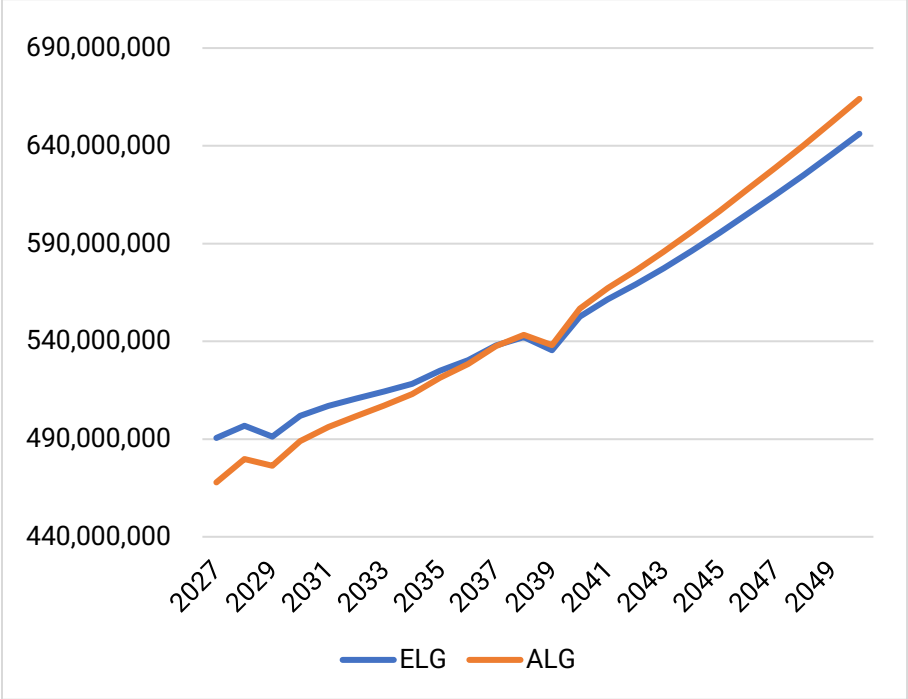
OCA Witness Garren's proposal is therefore not a recommendation that is in the long-term interest of lower customer rates. Instead, OCA Witness Garren's proposal

provides a short-term subsidy only to current customers who benefit from ELG depreciation rates paid by a previous generation of customers. The costs of a higher rate base will be paid for by future customers who will have to pay higher overall customer rates. Adopting ALG would serve as an intergenerational subsidy to current customers at the expense of future generations of customers.

Q. CAN YOU ILLUSTRATE THIS CONCEPT?

A. Yes, this concept is illustrated in UGI Gas Exhibit JFW-1R, which forecasts plant and reserve balances for UGI Gas through 2050 under two scenarios: one adopting the ALG procedure and the other maintaining the currently approved ELG procedure for vintages 1982 and newer. Figure 3 below shows a high-level estimate of the Company's revenue requirement (comprised of just depreciation expense and return) for the period 2027 through 2050 under each of these scenarios. This demonstrates that while ELG leads to higher depreciation expenses in the short term, it results in lower revenue requirements over the long term. The ELG approach is more beneficial to customers as it provides more stable and lower customer rates over time.

Figure 3. Comparison of Revenue Requirement



See below listing the components of the revenue requirement by year (in millions):

	EQUAL LIFE GROUP			AVERAGE LIFE GROUP		
TEST YEAR	DEPR. EXPENSE	RETURN	REV. REQMT	DEPR. EXPENSE	RETURN	REV. REQMT
2027	138.2	352.4	490.6	113.5	354.3	467.8
2028	145.0	351.8	496.8	124.3	355.4	479.7
2029	136.6	354.7	491.3	116.4	359.9	476.3
2030	144.0	357.9	501.9	124.3	364.7	489.0
2031	145.8	361.2	507.0	126.6	369.5	496.1
2032	146.1	364.7	510.7	127.3	374.5	501.7
2033	145.9	368.4	514.3	127.4	379.7	507.2
2034	145.8	372.5	518.3	127.7	385.3	512.9
2035	148.1	376.9	525.0	130.3	391.0	521.3
2036	149.0	381.4	530.4	131.4	397.0	528.4
2037	151.8	386.2	537.9	134.4	403.1	537.5
2038	151.4	390.8	542.2	134.2	409.2	543.4
2039	139.6	395.7	535.4	122.6	415.4	538.0
2040	149.7	402.8	552.6	132.9	423.9	556.7
2041	152.5	409.1	561.5	135.7	431.5	567.2
2042	153.8	415.3	569.1	137.1	439.0	576.2
2043	155.4	421.9	577.3	138.8	447.0	585.8
2044	157.3	428.8	586.1	140.8	455.2	596.0

	EQUAL LIFE GROUP			AVERAGE LIFE GROUP		
TEST YEAR	DEPR. EXPENSE	RETURN	REV. REQMT	DEPR. EXPENSE	RETURN	REV. REQMT
2045	159.5	435.9	595.5	143.1	463.6	606.7
2046	161.8	443.3	605.1	145.4	472.3	617.7
2047	164.0	450.9	614.9	147.6	481.2	628.8
2048	166.2	458.7	624.9	149.9	490.4	640.2
2049	168.6	466.8	635.4	152.2	499.7	651.9
2050	171.0	475.1	646.1	154.6	509.4	664.0

D. Intergenerational Inequity

Q. PLEASE EXPLAIN THE CONCEPT OF "INTERGENERATIONAL EQUITY."

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (e.g., from gas utility property used to provide gas service) by the same customers who pay for the cost of that asset – no more, no less. There are two related concepts when considering intergenerational equity as it pertains to depreciation. The first is the inequity that results when customers pay for assets from which they receive no service. For example, if an asset is retired before becoming fully depreciated, then customers subsequent to the asset's retirement will have to pay for an asset from which they are not receiving service. This is less equitable, as one generation of customers bears the cost of an asset from which they receive no service. Depreciation rates should be designed to avoid such an outcome. In real-world operations, circumstances can change such that assets are retired earlier than expected. However, this situation is different than designing depreciation rates to include intergenerational inequity, which should be avoided.

The second concept is related to the distribution of depreciation charges over the life of an asset. For example, if depreciation expense is higher in the earlier years of an

asset's life and lower in later years (or vice versa), this also is less equitable because one generation of customers pays a higher share than the next.

In my professional opinion, the first concept related to intergenerational equity can be more detrimental to customers than the second. That is, there is greater inequity resulting from a customer paying for an asset from which they received no service than the inequity resulting from one generation paying a somewhat different share of the same asset than another generation.

Q. HOW DOES THE EQUAL LIFE PROCEDURE CALCULATE DEPRECIATION EXPENSE?

A. The ELG procedure calculates depreciation expense for assets with like service lives within a depreciable group in accordance with the Iowa Survivor Curve proposed for the account and summing that depreciation expense for each similar life group of assets to develop an annual depreciation accrual rate applicable to the depreciable group. This procedure is designed to match the recovery of the assets' costs more appropriately to the period of time over which they are providing service to rate payers.

Q. HOW DOES THE AVERAGE LIFE GROUP (ALG) PROCEDURE CALCULATE DEPRECIATION EXPENSE?

A. The ALG procedure calculates depreciation expense by applying the same average service life from the proposed Iowa Survivor Curve to all assets within a depreciable group rather than grouping assets within a depreciable group by like service lives. The ALG procedure operates with the assumption that some of the assets within a depreciable group will retire prior the average service life applied to the entire depreciable group and other assets will survive longer than the average service life applied to the entire depreciable group.

Continuing, the ALG procedure assumes the over-recovery of the assets surviving longer than the average service life will offset the amount of the under-recovery of the assets retiring prior to reaching the average service life of the depreciable group.

Q. DOES THE USE OF ELG VS. ALG OR VICE VERSA IMPACT THE TOTAL AMOUNT OF ASSET COST TO BE RECOVERED?

A. No. Both procedures, when used in conjunction with the remaining life technique, are designed to recover the total service value of an asset over the asset's service life.

Q. DOES THE USE OF THE ELG PROCEDURE PRODUCE INTERGENERATIONAL INEQUITY?

A. No, quite the opposite. The very nature of the ELG procedure more precisely calculates depreciation expense for assets with an identical service life within a group known as an equal life group (i.e., one life for each equal life group) and sums that expense to develop an annual depreciation accrual rate applicable to the vintage. All vintages are summed, and a composite ELG accrual rate is determined for each plant account. As a result, it more appropriately matches the recovery of the assets' cost to the period of time over which it provides a service to rate payers.

In contrast, there is a stronger argument that the ALG procedure results in intergenerational *inequity*. Because depreciation expense on shorter-lived assets occurs over the average service life, recovery for these assets is deferred. ELG produces a more equitable recovery by recovering these costs over the actual service lives.

OCA Witness Garren claims the ELG procedure is an accelerated method of depreciation since it results in higher depreciation expense than the ALG procedure. OCA Witness Garren makes this observation since he is comparing the higher depreciation

expense from the ELG procedure to the results of the ALG procedure, using the ALG procedure from his perspective as the de facto benchmark. It is not. The ELG procedure is more precise and has been referred to by experts as the only mathematically correct depreciation procedure. Therefore, if there were a benchmark, it would be the ELG procedure since it is mathematically superior to the ALG procedure. If the situation, or one's perspective, were flipped and the ALG's depreciation expense were compared the depreciation expense calculated by the ELG procedure, the only mathematically correct depreciation procedure, one could make an argument that ALG procedure decelerates depreciation and defers full capital recovery until the oldest unit in the group is retired.

Q. DOES THE USE OF THE ELG PROCEDURE REQUIRE THE CALCULATION OF ANNUAL DEPRECIATION RATES TO BE UPDATED MORE FREQUENTLY THAN THE ALG PROCEDURE TO PREVENT INTERGENERATIONAL INEQUITY?

A. No. Regardless of the procedure selected, the calculation of depreciation expense and annual depreciation accrual rates determined on a remaining life basis, in particular, should be updated regularly to prevent intergenerational inequity. Both Mr. Garren and the Company recommend the use of the remaining life technique in connection with either the ALG or ELG procedure. Remaining life depreciation rates change each year regardless of whether the ALG or ELG procedure is used. Depreciation expense is determined by the future accruals, i.e., the original cost of an asset less accumulated depreciation, divided by the remaining life. All three components, i.e., plant balances, accumulated depreciation and the remaining lives, of this depreciation calculation change each year as new plant is added and existing plant is retired. Also, the assets in the following fiscal year are one year older

and one year closer to their retirement, so the composite remaining lives change each year as well. This is in addition to the change in the composition of an account's assets and their respective ages, which also impacts the composite remaining life. So Mr. Garren's criticism of the ELG procedure regarding it needs to be updated frequently to be accurate also applies to the ALG procedure when the remaining life technique is used.

Q. HOW FREQUENTLY DOES PENNSYLVANIA REGULATION REQUIRE THE CALCULATION OF DEPRECIATION RATES?

A. Pennsylvania regulation requires utilities operating within the state to calculate and file updated depreciation rates annually. In 1984, the Commission required utilities to submit annual depreciation reports (ADRs) which included updated depreciation rates and amounts using the most recent plant and reserve balances. This requirement and practice are unique to Pennsylvania and was developed, in part, over 40 years ago, to address the same concerns regarding the ELG procedure that Mr. Garren raises in this case. The annual depreciation reports provide the Commission with timely information each year and allow for effective monitoring of utility depreciation practices in Pennsylvania. The annual determination of depreciation rates and amounts in Pennsylvania addresses Mr. Garren's criticism that the ELG procedure should not be used because the depreciation rates need to be updated frequently, which is more frequent than every five years, in order to be valid. In Pennsylvania, this issue has been addressed as utilities file annual depreciation reports and update their depreciation rates accordingly, so Mr. Garren's criticisms of the ELG procedure are not applicable in Pennsylvania.

II. RATE BASE FOR FORECASTED TEST YEAR

A. Errors in OCA Witness Garren's Calculations

Q. DOES OCA WITNESS GARREN EXPLAIN WHY THERE IS JUSTIFICATION TO REDUCE DEPRECIATION EXPENSE IN THIS CASE?

A. No. The Company has followed the approved depreciation practices for over 40 years which include the use of the ELG procedure and submission of annual depreciation reports to the Commission. Customers have benefited from the ELG procedure for over 40 years, in that rate base is significantly less, i.e., ~$200M, had the ALG procedure been used during this period.

Q. IF THE ALG PROCEDURE WERE TO BE ADOPTED IN THIS CASE, IS OCA WITNESS GARREN'S STATED RATES CORRECT?

A. No. There are couple of significant problems with Mr. Garren's calculation. First, the estimated survivor curve that he has recommended and shown in Exhibit JSG-2 does not agree with the survivor curve he uses to calculate the composite remaining life in Exhibit JSG-3. Second, is that Mr. Garren's recommended depreciation expense claim is based on the future test year balances as of September 30, 2026 rather than the fully projected future test year balances as of September 30, 2027. When he was asked in discovery to explain his reason for basing his depreciation calculation on September 30, 2026, he failed to provide an explanation[11]. Third, OCA Witness Garren used the same accumulated depreciation amounts as the Company for his depreciation expense determination as of September 30, 2026, even though his recommendation to use the ALG procedure results in

[11] UGI Gas Exhibit JFW-2R [OCA Answer to UGI to OCA-II-8].

an annual reduction to depreciation expense, according to Mr. Garren, of $20.8M. His calculations are incorrect because he is using depreciation reserve balances that are too high and are based on projected book depreciation accruals using the ELG procedure. He should have projected the accumulated depreciation balances for the future test year and fully projected future test year using depreciation rates that were determined using his recommended ALG procedure and the three accounts where he recommended longer service lives. Instead he elected to use the same projected accumulated depreciation amounts as determined by the Company using the ELG procedure. Therefore, his accumulated depreciation amounts at September 30, 2027, should have been approximately $41.6M less ($20.8M less per year * 2 years = $41.6M).

Q. WHAT IS THE APPROPRIATE PROCESS FOR CALCULATING THE PROPOSED DEPRECIATION EXPENSE AND ANNUAL DEPRECIATION ACCRUAL RATES DURING A RATE CASE IN PENNSYLVANIA?

A. Pennsylvania provides for the calculation of proposed depreciation expense and annual depreciation accrual rates as of a FPFTY date. In the instant case, the FPFTY date is September 30, 2027 and not September 30, 2026 as Mr. Garren used in his determination of depreciation expense.

Q. PLEASE EXPLAIN HOW THE FPFTY LEVELS OF PLANT AND ACCUMULATED DERPECIATION (OR "RESERVE") ARE DEVELOPED?

A. The process begins with the calculation of depreciation expense and annual depreciation accrual rates as of a Historical Test Year ("HTY") which is completed using actual Plant and Reserve balances as of the end of the HTY, i.e., September 30, 2025. Once depreciation expense and annual depreciation accrual rates are calculated as of the HTY

date using the recommended depreciation procedure (i.e., ELG for the Company's proposal and ALG for the OCA's proposal), the depreciation rates are used along with projected plant and reserve activity to develop the plant and reserve balances as of the end of the Future Test Year ("FTY"), September 30, 2026. The September 30, 2026 plant and reserve balances are used to calculate depreciation accrual rates to determine book accruals in the Fully Projected Future Test Year ("FPFTY"). Similar to the FTY, the plant and reserve activity for the FPFTY are summed to determine the plant and reserve balances as of September 30, 2027, the end of the FPFTY. Once the forecasted plant and reserve balances are determined, a pro forma depreciation calculation can be performed as of September 30, 2027. The results of this depreciation calculation using the ELG procedure are the basis for the Company's depreciation expense claim.

Q. IS IT IMPORTANT TO MAINTAIN A CONSISTENT PROCESS AND CONSISTENT PROCEDURES DURING THE PROCESS DESCRIBED ABOVE?

A. Yes, it is. Maintaining a consistent process and procedures eliminates the possibility of increasing or decreasing swings in the levels of depreciation expense and annual depreciation accrual rates such as what OCA Witness Garren is proposing.

Q. HAS OCA WITNESS GARREN FOLLOWED THE ABOVE DESCRIBED PENNSYLVANIA PROCESS WHEN CALCULATING HIS PROPOSED LEVELS OF DEPRECIATION EXPENSE AND ANNUAL DEPRECIATION ACCRUAL RATES?

A. No.

Q. PLEASE DESCRIBE HOW OCA WITNESS GARREN HAS DEVIATED FROM THE PENNSYLVANIA PROCESS DESCRIBED ABOVE.

A. First, OCA Witness Garren has **NOT** calculated depreciation expense and rates as of each test period, and he does **NOT** calculate or use the results of each test year calculation to develop the forecasted reserve for each subsequent depreciation calculation. He has completely ignored and skipped portions of the process related to calculating depreciation for each test period using his recommended ALG procedure and survivor curve estimates. Instead he uses the forecasted reserve amounts developed by the Company. The Company's forecasted reserve amounts were determined using the ELG procedure and shorter service lives for 3 accounts which results in higher accruals and higher reserve balances than the ALG procedure and survivor curve estimates recommended by Mr. Garren. Finally, Mr. Garren applies his proposed ALG alternative procedure to calculate annual depreciation accrual rates and amounts as of September 30, 2026. The result of this erroneous process used by Mr. Garren is his depreciation expense claim is lower than it should have been had he determined it correctly.

III. SERVICE LIFE ANALYSIS

Q. DID OCA WITNESS GARREN PROPOSE CHANGES TO ANY OF THE SERVICE LIVES FOR ANY ASSET CLASS PROPOSED BY UGI GAS?

A. Please see Table 1 below for a summary of the service life estimates made by each party for gas plant. This table also includes the currently approved service life estimate.

Table 1: Comparison of Company Proposed and OCA Proposed Survivor Curves

Account	Currently Approved	Company Proposed	OCA Proposed
375.00, STRUCTURES AND IMP.	50-S0.5	50-S0.5	70-O1
376.10, MAINS, PRIMARILY STEEL	75-R2.5	75-R2.5	79-R2
378.00, MEAS. AND REG. EQUIPMENT	48-S0	48-S0	53-R0.5

Q. OCA WITNESS GARREN HAS PROPOSED LONGER SERVICE LIVES FOR SEVERAL ACCOUNTS. DO YOU AGREE WITH HIS PROPOSAL?

A. No. In general, the proposal of OCA Witness Garren results in unrealistic expectations of the future service lives of the Company's assets. More precisely, his proposal results in service life estimates that are unreasonably long for the actual assets studied and the Company's current and future operating environment.

Q. DOES MR. GARREN PRESENT AN INDEPENDENT SERVICE LIFE STUDY FOR UGI GAS IN THIS PROCEEDING?

A. No. Mr. Garren spends a substantial portion of his testimony describing how to perform a service life study including the relevant factors a depreciation professional should consider when forecasting the service lives of gas plant. However, Mr. Garren does not actually conduct a separate service life study comparable to the one the Company filed. Mr. Garren references the National Association of Regulatory Utility Commissioners ("NARUC") depreciation manual titled, Public Utility Depreciation Practices (a.k.a., "NARUC Manual") several times throughout his direct testimony. The NARUC Manual is an authoritative depreciation textbook on how to properly perform a service life study, and it describes the major work tasks involved. The irony is that while Mr. Garren describes the various tasks of what should be done when conducting a proper service life study, he fails to perform one. His service life analysis is mostly a mathematical curve-fitting exercise in which he selects the best fit survivor curve from a suitable curve type without the proper application of professional judgment using the combination of experience and placement bands that Mr. Wiedmayer had selected and were included in the Company's service life study and workpapers.

Q. DO YOU HAVE ADDITIONAL COMMENTS ON THE PROCESS MR. GARREN USED TO SELECT HIS RECOMMENDED SURVIVOR CURVES?

A. Yes, I do. On page 20 of OCA St. 4 (Mr Garren's testimony), he indicates that it is not appropriate to include certain statistically insignificant data points from the life table as this would skew the mathematical curve-fitting results. He states that the older accounting data may have accounting anomalies and that excluding these data points from the original life table is appropriate. He states that disregarding the oldest aged assets is called a T-cut and it occurs at the age interval containing the last statistically significant data point on the life table. I agree with all of this. Finally, Mr. Garren goes on to state that, "[t]he decision to make a T-cut, and at what point in the data set (i.e., original life table) to make the cut, is one of the most important yet subjective elements to an actuarial analysis".[12] However when I asked him in discovery for his T-cuts, he said he did not use T-cuts in the process of evaluating UGI Gas's depreciation rates.

Again Mr. Garren states in his testimony what the appropriate industry standard method is, but then once again does something else. He does not use proper professional judgment in selecting his T-cuts.

Q. WHAT FORMS THE BASIS OF THE SERVICE LIFE STUDY ON WHICH MR. GARREN BASED HIS SURVIVOR CURVE ESTIMATES?

A. It is unclear. Mr. Garren states in his testimony that the service life analysis was conducted as of the future test year, September 30, 2026. However, he provides no support for this study. He also claims to have used the results of the Company's service life study which was submitted to the Commission in 2023 using plant accounting data through September

[12] OCA St. 4, at p 21.

30, 2022. Irrespective of these items, OCA Witness Garren proposes different survivor curves for three accounts and describes those selections in narrative form.

1. <u>Account 375.00, Structures and Improvements</u>

Q. WHAT ARE THE RECOMMENDATIONS FOR THIS ACCOUNT?

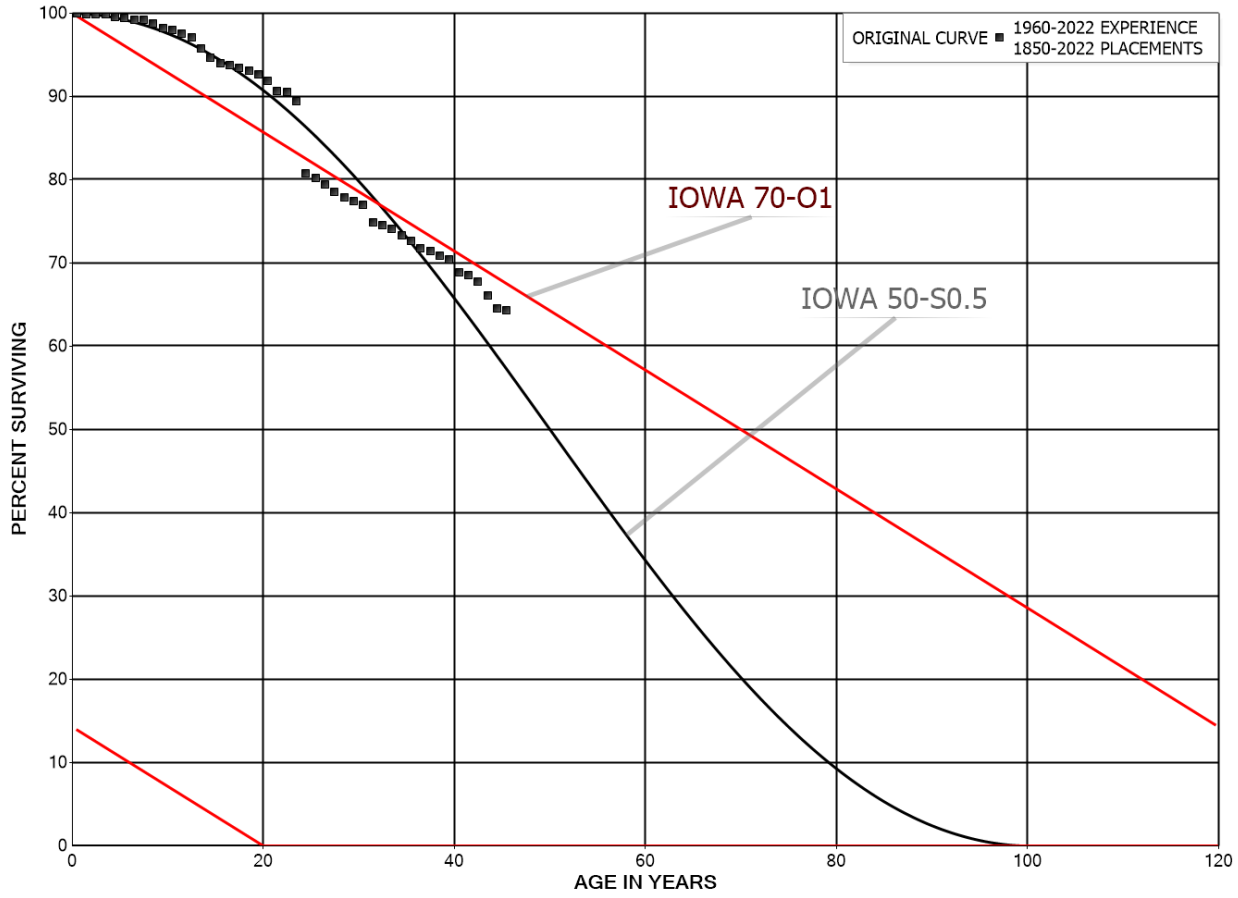
A. The currently approved estimate for Account 375.00, Structures and Improvements is a 50-S0.5 survivor curve. The Company proposes maintaining this estimate. Mr. Garren proposes a 70-O1 curve.[13]

Q. WHAT IS THE BASIS FOR MR. GARREN'S ESTIMATE?

A. Mr. Garren only discusses the statistical life analysis from the Company's service life study and industry averages in support of his estimate

[13] OCA St. 4, at p. 28.

Figure 1: Comparison of Company Proposed and OCA Proposed Survivor Curves to Historical Data for Account 375.00, Structures and Improvements



Q. IS MR. GARREN'S ESTIMATE FOR THIS ACCOUNT REASONABLE?

A. No. A 20-year life extension to the currently approved 50-year life for Account 375, Structures and Improvements is not reasonable. In general, the average service lives for gas distribution plant typically experience gradual life changes in connection with a revised service life study, in 1 to 3 year increments, over a 5 year period. A five year period is the number of years between service life studies, when there is an opportunity to make appropriate service life changes. Therefore, a twenty year increase proposed by OCA Witness Garren in the average service life for this account is unreasonable. This relatively minor account, in terms of plant investment (~$7.5M), primarily includes chain-link

fencing, concrete pads and small pre-engineered metal buildings and sheds and associated security systems at the Company's city gate and district measuring and regulating (M&R) stations. UGI operates 94 city gate stations and 1,359 district M&R stations. It is not reasonable to recommend a 70-year average service life for this account which includes small, pre-engineered buildings and chain-link fencing. Most other gas companies use average service lives in the 45-60 year range. Also, it is not reasonable to expect that the maximum life for assets in this account would extend to 140 years, as the 70-O1 survivor curve recommended by OCA Witness Garren would suggest. The 50-S0.5 survivor curve recommended by the Company indicates 10 percent of the assets surviving at age 80 and a more reasonable maximum life of 100 years. Mr. Garren does not provide sufficient support for his recommended lengthy 20-year service life extension, and a 70 year average service life estimate is outside the typical industry range of service lives used by other gas companies, and therefore his proposal should be rejected.

2. Account 376.10, Mains – Primarily Steel

Q. WHAT ARE THE RECOMMENDATIONS FOR THIS ACCOUNT?

A. The currently approved estimate for Account 376.10, Mains – Primarily Steel, is a 75-R2.5 survivor curve. The Company continues to support this estimate, and Mr. Garren proposes a 79-R2 curve.[14]

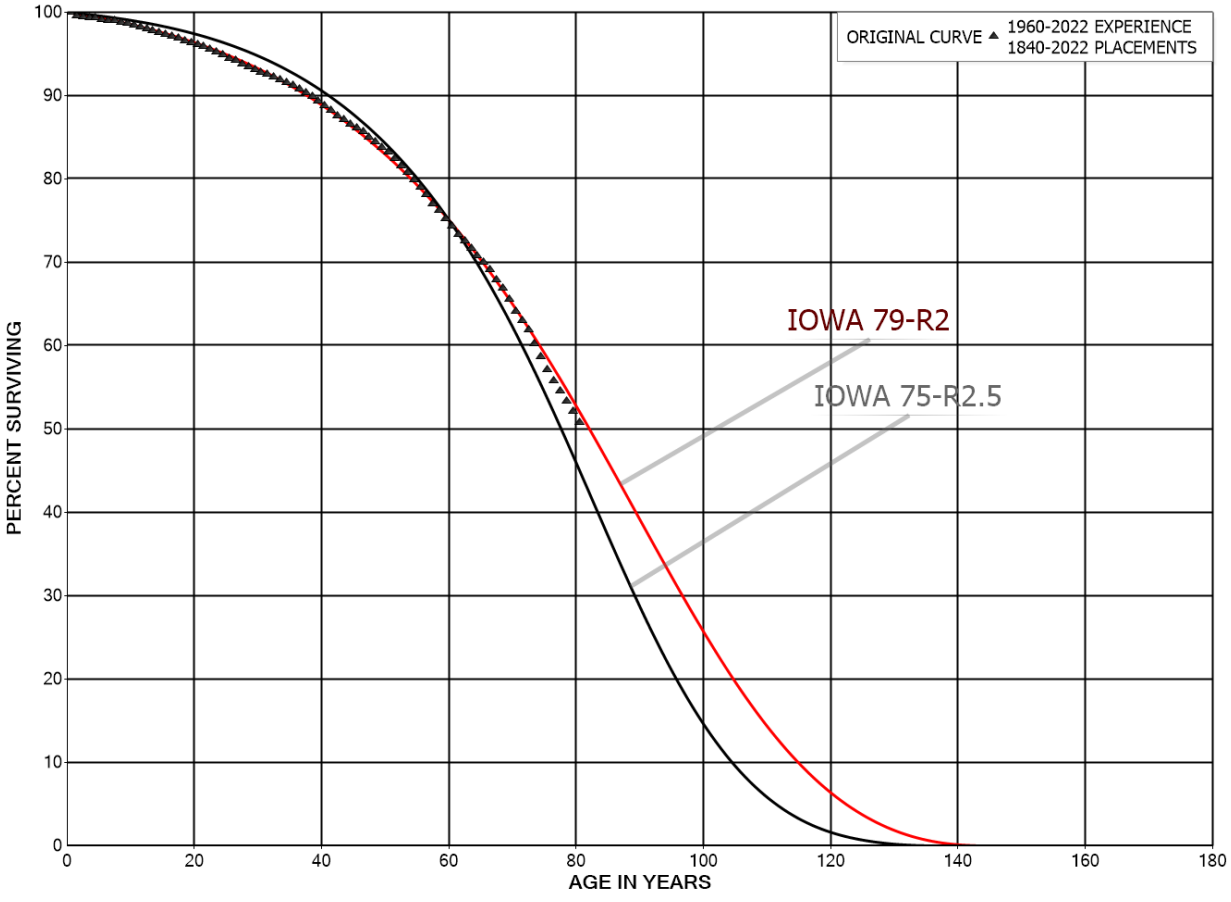
Q. WHAT IS THE BASIS FOR MR. GARREN'S ESTIMATE?

[14] OCA St. 4, at p. 29.

A. Again, Mr. Garren only discusses the statistical analysis in support of his estimate, which suggests that the 79-R2 estimate is primarily based on the mathematical curve-fitting results. The 79-R2 is the best mathematical fit to historical data and that is the basis for Mr. Garren's selection. While the 79-R2 survivor curve is the best fit curve to the historical experience, the Company's proposed survivor curve, the Iowa 75-R2.5, fits the historical data reasonably well, too. The difference in the shape of the two survivor curves primarily occurs after age 65 when the rates of retirement related to the 75-R2.5 show a greater increase than the 79-R2. In my view, rates of retirements at age 65 or more will increase in the future. This is based on my discussion with Company engineers and the Company's plan set forth in their Third Long Term Infrastructure Improvement Plan ("LTIIP"). In 2012, UGI Gas implemented a program to accelerate its replacement related to non-contemporary mains, such as cast iron, wrought iron, unprotected coated steel, certain vintage plastic and bare steel mains. Unprotected coated steel and bare steel mains are included in this account, Account 376.1, Mains - Steel. Unprotected coated steel mains were primarily installed in the late 1950's through 1970 and bare steel mains were installed during the years 1924 through 1960. The Company still has a sizable portion of bare steel mains in service. The Company's plans regarding its mains replacement program are set forth in UGI's Third LTIIP. The LTIIP indicates a significant increase in the level of bare steel mains replaced. The LTIIP will result in increased retirements of bare steel at ages 65 and greater, compared to prior periods before 2012. The survivor curve proposed by the Company, i.e., 75-R2.5, reflects this occurrence and expectation. That is, the 75-R2.5 better reflects Company plans as set forth in the LTIIP and the expectation that increased levels of bare steel main retirements will accelerate, as the Company finishes their cast iron

main replacement. The replacement of bare steel mains at UGI Gas will continue to accelerate compared to prior periods before the LTIIP was developed and approved by the Commission. UGI Gas has committed to the Commission and has a legal obligation to remove all bare steel mains by 2041. The typical range of service lives used by other gas companies for steel mains is 65 to 75 years. The Company's proposed survivor curve estimate, i.e., the 75-R2.5, falls within the typical range while the OCA's recommended survivor curve estimate, i.e., the 79-R2, does not.

Figure 2: Comparison of Company Proposed and OCA Proposed Survivor Curves to Historical Data for Account 376.10, Mains – Primarily Steel



Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject Mr. Garren's proposed 79-R2 estimate. Mr. Garren does not present sufficient evidence to support an increase for this account.

3. Account 378.00, Measuring and Regulating Station Equipment - General

Q. WHAT ARE THE RECOMMENDATIONS FOR THIS ACCOUNT?

A. The currently approved estimate for Account 378.00, Measuring and Regulating Station Equipment, is a 48-S0 survivor curve, which the Company continues to support in the recent depreciation study. Mr. Garren proposes a 53-R0.5 curve.[15]

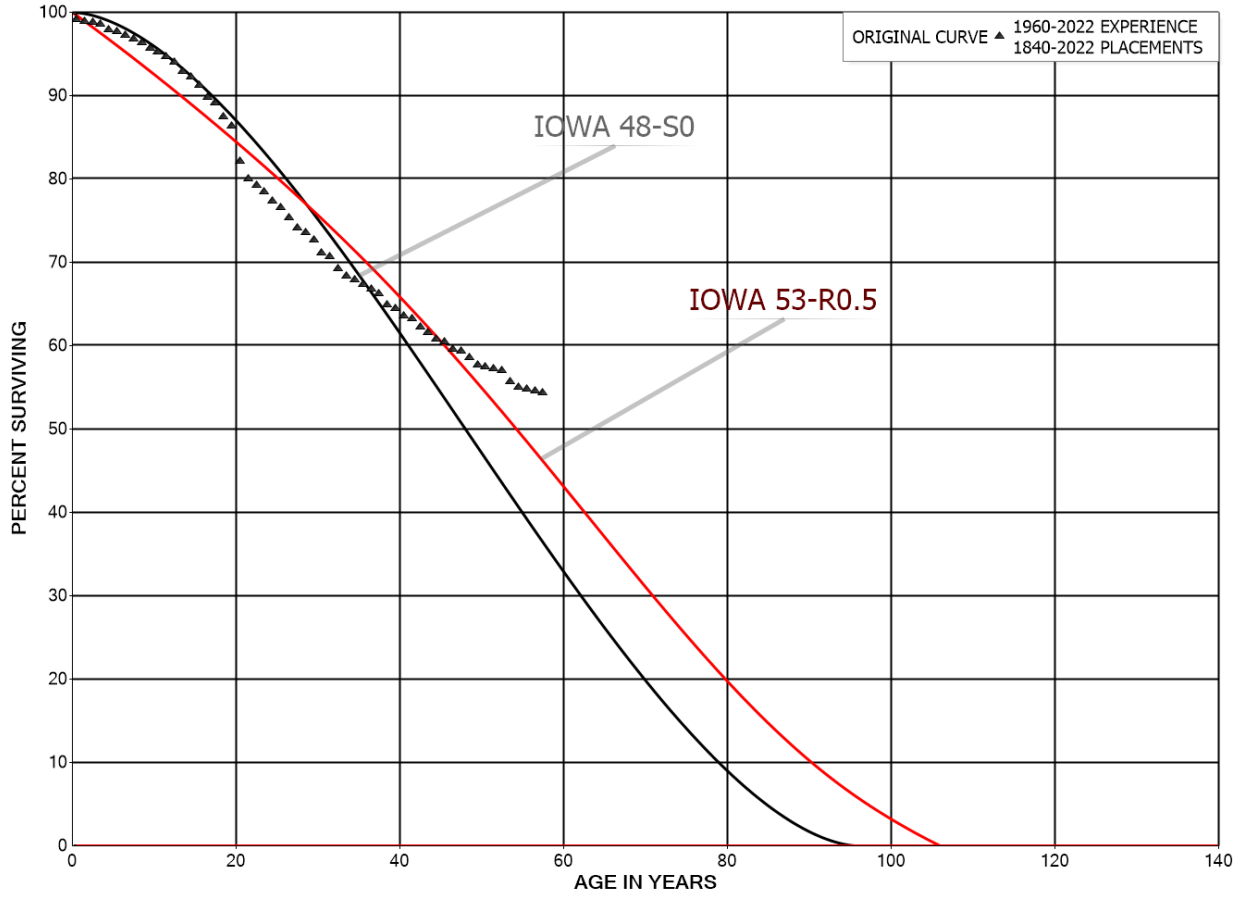
Q. WHAT IS THE BASIS FOR MR. GARREN'S ESTIMATE?

A. Again, Mr. Garren only discusses the statistical analysis in support of his estimate, which suggests that the 53-R0.5 estimate is primarily based on the mathematical curve-fitting results. That is, Mr. Garren simply reviewed the curve fitting results from the Company's service life study and workpapers and selected the best fitting R type curve. Neither of the survivor curves recommended by the parties are considered excellent fits to the historical data as shown in the chart below. Therefore, other relevant factors, such as the account content, the approved survivor curve estimate, Company plans, engineering service life outlook, and estimates used by other gas companies should be considered. In that regard, the approved estimate is the 48-S0. Given my prior comment that the average service life for gas distribution accounts typically change gradually in 1 to 3 year increments, a five year increase in service life proposed by Mr. Garren seems unreasonable. Especially since the service life study is the same one as presented in the prior UGI Gas base rate case submitted in 2025. The assets included in this account consists of metering equipment,

[15] OCA St. 4, at pp. 29-30.

gauges, SCADA and telemetry equipment, etc. These shorter lived items typically only last 20 to 30 years compared with the longer lived items in this account such as piping, valves, and regulators which can last 50 years or more. The typical range of service lives for Account 378 used by other gas companies is 40 to 50 years. In addition, as the Company completes its cast iron main replacement program, as set forth in the LTIIP, the low pressure service areas used in conjunction with cast iron mains will no longer be needed. Certain existing District M&R stations currently serving low pressure areas will no longer be needed and will be retired without replacement. Some district regulating stations will be consolidated. Therefore, the expectation is for increased retirements for Account 378, Measuring & Regulating Station Equipment. The 48-S0 survivor curve that I have recommended takes into consideration these other relevant factors while Mr. Garren's recommended 53-R0.5 survivor curve only considers the mathematical curve-fitting results from the historical life analysis.

Figure 3: Comparison of Company Proposed and OCA Proposed Survivor Curves to Historical Data for Account 378.00, Measuring and Regulating Station Equipment - General



Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject Mr. Garren's proposed 53-R0.5 estimate. Mr. Garren does not present sufficient evidence to support an increase for this account.

IV. OTHER ISSUES IN WITNESS GARREN'S TESTIMONY

Q. DOES MR. GARREN SUFFICIENTLY PROVIDE SUPPORT FOR THE SERVICE LIFE STUDY HE PURPORTS TO HAVE CONDUCTED?

A. No. As stated previously, Mr. Garren does not present an independent UGI Gas service life study comparable to the one the Company filed in this proceeding. Although he devotes

substantial portions of his testimony to general service life theory, actuarial concepts, and mathematical curve fitting, he does not present the actual results of a separate UGI Gas actuarial study (including original life tables as of the FTY) showing how his proposed survivor curves were derived. He did not provide sufficient information that would allow the Commission to evaluate whether his proposed survivor curves for Accounts 375, 376.1, and 378 are supported.

This lack of support is especially problematic because Mr. Garren states that his recommendations are based on plant balances as of the FTY. Service life studies, however, are ordinarily based on actual historical retirement experience and actuarial analysis of aged data, not hypothetical future activity.

Q. HAS MR. GARREN EVER CALCULATED DEPRECIATION USING THE EQUAL LIFE GROUP PROCEDURE OR RECOMMENDED THE EQUAL LIFE GROUP PROCEDURE TO A CLIENT?

A. No. Mr. Garren has neither calculated depreciation using the ELG procedure nor has he recommended its use to a client[16]. However, he offers criticisms of the ELG procedure having never used it previously, stating the ELG procedure: 1) results in accelerated depreciation; 2) that it is too precise for utility ratemaking; 3) that the rates are erratic and will become outdated if not updated frequently; and 4) that the ELG-RL procedure requires a higher level of administrative upkeep.

I have used the ELG procedure my entire 40 year career for numerous utility clients, including UGI Gas, and have updated UGI Gas's annual depreciations reports since 1989. I am of the opinion that none of the four criticisms offered by Mr. Garren regarding the

[16] UGI Gas Exhibit JFW-2R [OCA Answer to UGI to OCA-II-1 and UGI to OCA-II-11].

ELG procedure is valid based on my experience using the ELG procedure often, over the past 40 years. The depreciation rates for UGI Gas's distribution plant are stable with only minor changes each year.

Q. HAS MR. GARREN PROVIDED A FULLY DEVELOPED SET OF PROPOSED DEPRECIATION RATES AND ACCRUALS AS OF THE FULLY PROJECTED FUTURE TEST YEAR?

A. No. Mr. Garren does not provide a fully developed set of depreciation rates and accruals as of the FPFTY. Instead, his calculations are based on FTY balances, and he does not provide a corresponding FPFTY development that carries his proposed changes through the full reserve bring forward and rate calculation process. As a result, the Commission is not presented with a complete information supporting his proposed expense and rates.

Q. IS IT STANDARD PRACTICE IN PENNSYLVANIA TO CALCULATE DEPRECIATION EXPENSE AND ANNUAL ACCRUAL RATES AS OF THE FPFTY?

A. Yes. In Pennsylvania, the proper ratemaking process is to calculate depreciation expense and annual accrual rates on a fully projected future test year basis. That process begins with actual plant and reserve balances in the historic test year ("HTY"), brings those amounts forward to the future test year ("FTY") using projected plant activity, and then brings them forward again to the FPFTY, where the proposed depreciation expense and annual accrual rates are calculated.

It is also important that the same procedures be applied consistently throughout that process. A party cannot reasonably change life characteristics or depreciation procedures and then fail to reflect those changes in the corresponding reserve (a.k.a., accumulated

depreciation) development and FPFTY calculations. That is, the Pennsylvania framework is reflected in the Company's filing, and it is the framework that should be followed by any party proposing alternative depreciation parameters in this proceeding.

Q. ARE THERE OTHER ISSUES IN MR. GARREN'S EXHIBITS AND CALCULATIONS THAT SHOULD BE NOTED?

A. Yes. First, based on my review of Exhibit JSG-2, the survivor curve shown in column 3 for the three accounts he proposes to revise appears not to match the survivor curves stated in the body of his testimony. The survivor curves shown in this exhibit for Accounts 375.00, 376.10 and 378.00 are 80-O1, 75-R2.5 and 48-S0, respectively. This does not agree with other sections and exhibits within his testimony.

V. CONCLUSION

Q. IS THERE ANYTHING IN THE TESTIMONY OF OCA WITNESS GARREN THAT SHOULD INFLUENCE THE COMMISSION TO ACCEPT HIS DEPRECIATION RECOMMENDATIONS?

A. No. Mr. Garren's testimony does not provide sufficient support for his proposed service life changes, does not present a complete FPFTY depreciation development, and does not justify replacing the Company's supported depreciation methodology and calculations that are based on long-standing Commission precedent with his alternative recommendations. OCA has presented invalid criticisms of the ELG procedure and has made a misleading recommendation to the Commission by not fully and properly addressing how depreciation affects the revenue requirement and customer rates. The Commission should continue to approve the ELG depreciation rates as recommended in the Company's filing.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

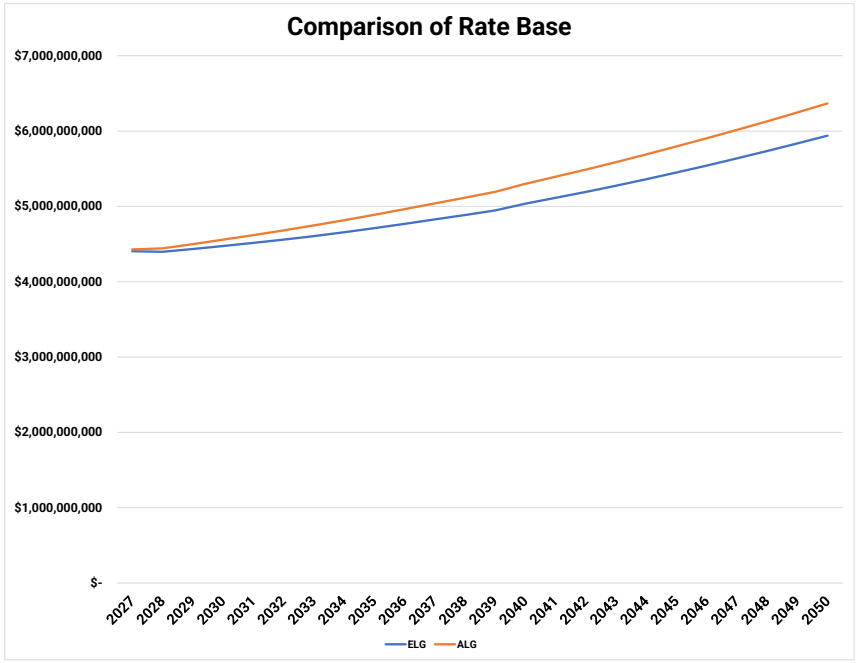
A. Yes, it does.

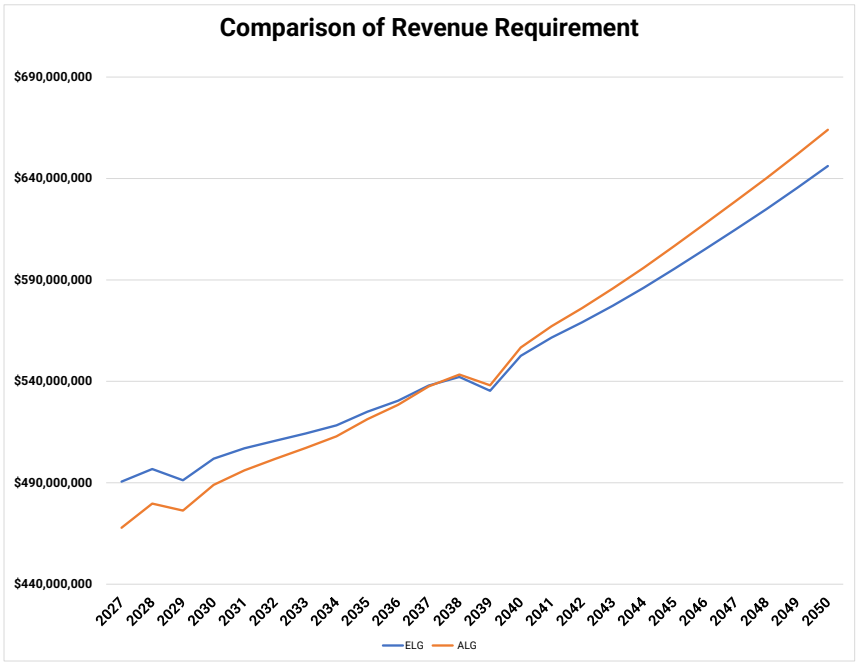
UGI Gas Exhibit JFW-1R

UGI CORPORATION - GAS DIVISION

Assumptions
0 *Future Net Salvage*
8.0% *Rate of Return*

		EQUAL LIFE GROUP								AVERAGE LIFE GROUP								
TEST YEAR	AVERAGE ORIGINAL COST	BOOK RESERVE	COMPOSITE REMAINING LIFE	FUTURE ACCRUALS	DEPRECIATION	RATE	RETURN	REVENUE REQUIREMENT	RATE BASE	BOOK RESERVE	COMPOSITE REMAINING LIFE	FUTURE ACCRUALS	EXPENSE	RATE	RETURN	REVENUE REQUIREMENT	RATE BASE	RETIREMENTS	NET SALVAGE
2026	5,936,133,917	1,523,817,454	31.9	4,412,316,459						1,523,817,454	38.9	4,412,316,459							
2027	5,966,876,313	1,562,266,722	30.6	4,435,351,986	138,201,584	2.32	352,368,767	490,570,351	4,404,609,591	1,538,045,512	35.9	4,459,573,196	113,522,151	1.90	354,306,464	467,828,615	4,428,830,801	39,972,623	-
2028	6,057,025,653	1,659,643,610	32.6	4,456,788,988	145,004,679	2.39	351,790,563	496,795,242	4,397,382,043	1,614,754,012	38.7	4,501,678,586	124,336,290	2.05	355,381,731	479,718,021	4,442,271,642	47,627,791	-
2029	6,185,869,364	1,751,930,858	31.3	4,503,375,272	136,558,677	2.21	354,715,080	491,273,757	4,433,938,506	1,686,837,645	36.8	4,568,468,485	116,355,063	1.88	359,922,538	476,277,601	4,499,031,719	44,271,430	-
2030	6,327,574,722	1,854,030,349	31.2	4,545,812,966	143,979,808	2.28	357,883,550	501,863,358	4,473,544,374	1,769,259,357	36.6	4,630,583,957	124,302,029	1.96	364,665,229	488,967,258	4,558,315,365	41,880,317	-
2031	6,472,010,458	1,957,199,740	31.4	4,586,977,861	145,826,698	2.25	361,184,857	507,011,555	4,514,810,718	1,853,232,247	36.9	4,690,945,354	126,630,197	1.96	369,502,257	496,132,454	4,618,778,211	42,657,307	-
2032	6,617,547,836	2,059,344,766	31.8	4,631,573,306	146,053,742	2.21	364,656,246	510,709,988	4,558,203,071	1,936,595,831	37.3	4,754,322,240	127,272,300	1.92	374,476,160	501,748,460	4,680,952,005	43,908,716	-
2033	6,763,844,323	2,158,301,429	32.1	4,678,469,146	145,850,642	2.16	368,443,432	514,294,074	4,605,542,895	2,017,133,767	37.8	4,819,636,808	127,431,915	1.88	379,736,844	507,168,759	4,746,710,556	46,893,979	-
2034	6,913,652,399	2,257,214,751	32.0	4,733,319,471	145,780,301	2.11	372,515,012	518,295,313	4,656,437,648	2,097,937,809	37.5	4,892,596,413	127,671,020	1.85	385,257,167	512,928,187	4,815,714,590	46,866,979	-
2035	7,067,043,143	2,356,136,094	32.1	4,787,415,971	148,145,529	2.10	376,872,564	525,018,093	4,710,907,049	2,179,021,436	37.8	4,964,530,629	130,307,813	1.84	391,041,737	521,349,550	4,888,021,708	49,224,186	-
2036	7,223,167,345	2,455,413,074	31.9	4,847,369,550	148,997,348	2.06	381,420,342	530,417,690	4,767,754,271	2,260,713,760	37.5	5,042,068,864	131,412,693	1.82	396,996,287	528,408,980	4,962,453,585	49,720,368	-
2037	7,380,352,433	2,553,263,421	32.4	4,904,658,820	151,750,081	2.06	386,167,121	537,917,202	4,827,089,011	2,341,177,621	38.1	5,116,744,620	134,363,595	1.82	403,133,985	537,497,580	5,039,174,812	53,899,734	-
2038	7,502,961,541	2,617,751,800	35.3	4,930,249,041	151,387,922	2.02	390,816,779	542,204,701	4,885,209,741	2,388,470,085	42.1	5,159,530,757	134,192,007	1.79	409,159,317	543,351,324	5,114,491,457	86,899,543	-
2039	7,642,274,043	2,695,879,615	33.7	5,040,667,630	139,648,169	1.83	395,711,554	535,359,723	4,946,394,428	2,449,566,723	39.8	5,286,980,522	122,616,992	1.60	415,416,586	538,033,578	5,192,707,320	61,520,354	-
2040	7,822,874,218	2,787,643,214	33.6	5,121,557,976	149,748,560	1.91	402,818,480	552,567,040	5,035,231,004	2,524,435,545	39.7	5,384,765,645	132,853,784	1.70	423,875,094	556,728,878	5,298,438,672	57,984,961	-
2041	7,991,920,097	2,878,450,684	33.8	5,196,188,319	152,456,550	1.91	409,077,553	561,534,103	5,113,469,412	2,598,461,512	39.9	5,476,177,491	135,675,046	1.70	431,476,687	567,151,733	5,393,458,585	61,649,079	-
2042	8,160,719,654	2,969,509,289	34.0	5,277,291,015	153,815,787	1.88	415,296,829	569,112,616	5,191,210,364	2,672,843,817	40.1	5,573,956,487	137,139,488	1.68	439,030,067	576,169,555	5,487,875,837	62,757,182	-
2043	8,335,175,805	3,061,354,996	34.1	5,362,196,310	155,428,048	1.86	421,905,665	577,333,713	5,273,820,809	2,748,099,588	40.3	5,675,451,718	138,838,113	1.67	446,966,097	585,804,210	5,587,076,217	63,582,341	-
2044	8,514,531,531	3,154,636,345	34.2	5,450,875,410	157,329,834	1.85	428,791,615	586,121,449	5,359,895,186	2,824,847,952	40.4	5,780,663,803	140,796,849	1.65	455,174,686	595,971,535	5,689,683,579	64,048,486	-
2045	8,698,759,747	3,249,462,114	34.3	5,542,545,625	159,522,849	1.83	435,943,811	595,466,660	5,449,297,633	2,903,219,956	40.5	5,888,787,782	143,069,085	1.64	463,643,183	606,712,268	5,795,539,790	64,697,080	-
2046	8,886,041,189	3,344,469,284	34.4	5,635,605,356	161,818,791	1.82	443,325,752	605,144,543	5,541,571,905	2,981,804,800	40.6	5,998,269,840	145,396,465	1.64	472,338,911	617,735,376	5,904,236,389	66,811,621	-
2047	9,075,671,440	3,439,476,934	34.5	5,731,791,307	164,021,227	1.81	450,895,561	614,916,788	5,636,194,507	3,060,413,067	40.8	6,110,855,173	147,621,844	1.63	481,220,670	628,842,514	6,015,258,373	69,013,577	-
2048	9,268,455,429	3,534,420,692	34.6	5,831,221,927	166,221,887	1.79	458,722,779	624,944,666	5,734,034,737	3,138,987,300	40.9	6,226,655,319	149,852,361	1.62	490,357,450	640,209,811	6,129,468,130	71,278,129	-
2049	9,464,382,451	3,629,345,066	34.7	5,933,777,217	168,574,917	1.78	466,802,991	635,377,908	5,835,037,385	3,217,531,613	41.0	6,345,590,670	152,194,857	1.61	499,748,067	651,942,924	6,246,850,838	73,650,543	-
2050	9,663,381,416	3,724,209,845	34.8	6,039,430,703	171,014,014	1.77	475,133,726	646,147,740	5,939,171,570	3,296,007,129	41.2	6,467,633,419	154,624,751	1.60	509,389,943	664,014,694	6,367,374,287	76,149,235	-
					3,647,137,646		***9,623,260,629***						***3,218,476,707***		***10,072,217,157***				





UGI Gas Exhibit JFW-2R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

1. Has Mr. Garren ever recommended the Equal Life Group (ELG) procedure to his clients?

   a. If yes, please provide the docket number, client and jurisdiction.

OCA Response:

To the best of Mr. Garren's recollection, he has never recommended the ELG procedure to his clients.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

2. Reference OCA St. 4, page 24. Mr. Garren states that, "[t]he ELG method potentially better reflects the actual retirement patterns of a group of assets with different vintages at a specific point in time, but requires constant updating to remain accurate."

   a. Regarding the depreciation calculations using the ELG procedure and summarized in Table 1 of Book VI, Exhibit C (Fully Projected Future), what specific amounts and values change in each accounting period that support Mr. Garren's claim that the ELG procedure requires constant updating to remain accurate.

   b. In Mr. Garren's opinion, how often are depreciation calculations using the Equal Life Group (ELG) procedure needed to be updated in order for the depreciation rates to "remain accurate"?

OCA Response:

For subpart a., please see Mr. Garren's direct testimony at page 23.

For subpart b., Pennsylvania requires utilities to file annual report on depreciation and depreciation studies every five years in part to address the need for these calculations to remain accurate. If remaining lives are not calculated every five years at the maximum, there is real danger that the ELG methodology will result in large rate and expense changes from study to study.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

8. Did the OCA calculate depreciation expense using balances as of September 30, 2027?

   a. If yes, please state where in the testimony that can be found and provide the calculations to support your answer.

   b. If no, please explain why Mr. Garren did not perform the depreciation calculations using the plant and reserve balances as of September 30, 2027, the end of the fully projected future test year.

OCA Response:

No, see attachment provided in response to UGI's request to OCA II.4.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

9. Please provide the T-cuts by account used by Mr. Garren.

OCA Response:

Mr. Garren did not use T-cuts in the process of evaluating UGI-Gas's depreciation rates.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

10. Did Mr. Garren perform his own original service life analysis in the current proceeding?

    a. If yes, please provide all supporting life tables and charts for each plant account analyzed.

    b. If the answer to Question 10 above is "no", please provide an explanation why Mr. Garren did not perform his own original service life analysis?

OCA Response:

Mr. Garren did not perform his own service life analysis in the current proceeding. Mr. Garren relied upon Mr. Wiedmayer's analysis to arrive at his conclusions, and proposed adjustments where Mr. Wiedmayer deviated from the results of his own analysis without providing adequate justification for disregarding the historical analysis of service lives.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

11. Has Mr. Garren ever made depreciation calculations using the Equal Life Group procedure for any reason, such as a sensitivity analysis?

OCA Response:

No.

RESPONDENT: James Garren

Dated: May 4, 2026

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET II

12. Has Mr. Garren taken any field trips or site visits to observe UGI Gas Division's facilities?

OCA Response:

No. Mr. Garren relied upon Mr. Wiedmayer's observations regarding UGI gas's physical plant.

RESPONDENT: James Garren

Dated: May 4, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 7-R

Rebuttal Testimony of
Vicky A. Schappell

Topics Addressed: **Fully Projected Future Test Year**
Reporting Requirements

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 7, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"). Specifically, I respond to the direct testimony of Ethan Cline, I&E Statement No. 3.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No. I am not sponsoring any exhibits with my rebuttal testimony.

II. FULLY PROJECTED FUTURE TEST YEAR REPORTING REQUIREMENTS

Q. Did I&E have any recommendations regarding Plant Additions for the Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY")?

A. Yes. I&E recommends that the Company be required to provide I&E, the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA") with an update to the UGI Exhibit A – FTY, Schedule C-2 no later than February 1, 2027, which should include actual capital expenditures, plant additions, and retirements by month for

the twelve months ending September 30, 2026. He also recommends that an update to the UGI Exhibit A – FPFTY, Schedule C-2 should also be provided for actuals through September 30, 2027, no later than February 1, 2028.

Q. Does the Company agree with Mr. Cline's recommendation?

A. Yes. UGI Gas will submit an update to the UGI Gas Exhibit A, Schedule C-2 no later than February 1, 2027, for the FTY, which will include actual capital expenditures, plant additions and retirements from October 1, 2025, through September 30, 2026. An additional update will be submitted by February 1, 2028, for the FPFTY, with the actuals from October 1, 2026, through September 30, 2027.

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 8-R

Rebuttal Testimony of Dylan W. D'Ascendis

Topics Addressed: **Return on Equity**

Dated: May 13, 2026

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I. INTRODUCTION, PURPOSE AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this rebuttal testimony (referred to throughout as my "Rebuttal Testimony") before the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission") on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is two-fold. First, I update the analyses in my Direct Testimony to reflect current data. Second, I address certain aspects of the direct testimonies of Mr. Drew Breuning, witness for the PA PUC's Bureau of Investigation and Enforcement ("I&E"), Mr. David J. Garrett, witness for the Pennsylvania Office of Consumer Advocate ("OCA"), Mr. Mark D. Ewen, witness for the Pennsylvania Office of Small Business Advocate ("OSBA"), and Mr. Patrick M. Cicero, witness for The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), (collectively referred to as the "Opposing Witnesses") as they pertain to the Company's allowed capital structure and associated cost rates, which the Company should have the opportunity to earn on its authorized jurisdictional rate base.

Q. PLEASE SUMMARIZE THE KEY ISSUES AND RECOMMENDATIONS OFFERED BY THE OPPOSING WITNESSES THAT YOU ADDRESS IN YOUR REBUTTAL TESTIMONY.

A. Due to the passage of time since my Direct Testimony analysis (which included data as of October 31, 2025), I have updated my analysis using data as of March 31, 2026. Based on these updated analyses, the reasonable range of ROEs attributable to the Company is from 10.57% to 12.07%. Given this range, my recommended ROE for the Company of 10.75% continues to be reasonable, if not conservative.[1] Conversely, recommended ROEs of 9.81% (Mr. Breuning), and 8.80% (Mr. Garrett) are inadequate at this time.[2]

My Rebuttal Testimony also responds to substantive recommendations offered by the Opposing Witnesses in their direct testimonies, which include their opinions on the appropriate rate making capital structure for the Company, applications of the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), their consideration of authorized ROEs in other jurisdictions for the determination of the ROE in this proceeding, contentions regarding the Company's regulatory mechanisms and its relative risk, and their failure to reflect Company-specific factors such as relative size and flotation costs, in their recommendations. My Rebuttal Testimony discusses these factors and others in detail. Finally, my Rebuttal Testimony also addresses the unfounded critiques of my Direct Testimony.

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[1] My initial analysis indicated a range of reasonable ROEs between 10.34% and 11.52%. *See* UGI Gas St. No. 8, at p. 4.

[2] While they did not conduct an independent market-based analysis of the cost of common equity, and do not provide specific ROE recommendations, Messrs. Ewen and Cicero imply that ROEs of 9.00% and 7.70% are adequate to attract capital. As explained herein, these implied ROEs are also inadequate.

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I have prepared UGI Gas Rebuttal Exhibit B, which includes Schedules DWD-1R through DWD-12R, which have been prepared by me or under my direct supervision.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- Section II – Presents my updated analysis;
- Section III – Discusses the appropriate ratemaking capital structure;
- Section IV – Contains my response to Mr. Breuning;
- Section V – Contains my response to Mr. Garrett;
- Section VI – Contains my response to Mr. Ewen;
- Section VII – Contains my response to Mr. Cicero; and
- Section VIII – Summarizes my conclusions and recommendations.

II. <u>UPDATED ANALYSIS</u>

Q. HAVE YOU UPDATED YOUR COST OF CAPITAL ANALYES?

A. Yes, I have. Due to the passage of time since my Direct Testimony analysis (which included data as of October 31, 2025), I have updated my analysis using data as of March 31, 2026. I used the Company's updated cost of debt based on new information.

Q. HAVE YOU APPLIED ANY OF YOUR ROE MODELS DIFFERENTLY IN YOUR UPDATED ANALYSES?

A. No, I have not.

Q. HAVE YOU UPDATED YOUR UTILITY PROXY GROUP IN YOUR UPDATED ANALYSES?

A. Yes, I have. My second selection criteria specifies that a company must have 60% or greater of the respective fiscal year total operating income derived from, or 60% or greater of the respective fiscal year total assets attributable to regulated gas distribution operations.[3] Chesapeake Utilities Corporation ("CPK") no longer meets this criteria based on fiscal year 2025 data. Without CPK, the Utility Proxy Group consists of the following six companies:

Table 1: Utility Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX

Q. PLEASE SUMMARIZE YOUR UPDATED COST OF COMMON EQUITY RESULTS BASED ON YOUR UPDATED ANALYSES.

A. Using data as of March 31, 2026, my updated results are presented in page 2 of Schedule DWD-1R, and in Table 2, below.

[3] UGI Gas St. No. 8, at p. 13.

Table 2: Summary of Updated Common Equity Rate

Discounted Cash Flow Model (DCF)	10.40%
Risk Premium Model ("RPM")	10.68% - 11.13%
Capital Asset Pricing Model (CAPM)	10.60% - 11.90%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	10.80% - 11.67%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.40% - 11.90%
Business Risk Adjustment	0.05%
Flotation Cost Adjustment	0.12%
Indicated Range of Common Equity Cost Rates after Adjustment	10.57% - 12.07%
Recommended Cost of Equity	10.75%

In view of the unadjusted and adjusted ranges of ROEs, I maintain my original recommendation of 10.75% for the Company.

III. APPROPRIATE RATEMAKING CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES POSITIONS REGARDING CAPITAL STRUCTURE.

A. Mr. Breuning accepts the Company's requested capital structure and long-term debt cost rate, noting both the Company's requested equity ratio and long-term debt cost rate is within the range set by his proxy group companies.[4] Mr. Garrett recommends a hypothetical capital structure, consisting of 51.00% long-term debt and 49.00% common equity, based on the average capital structure maintained by his proxy group.[5] Mr. Garrett

[4] I&E St. No. 2, at pp. 12, 19.
[5] OCA St. 3, at p. 3.

accepts the Company's long-term debt cost rate.[6] Mr. Cicero recommends a hypothetical capital structure consisting of 50.00% long-term debt and 50.00% common equity, but does not provide any market-based analysis as to why his recommendation is reasonable.[7]

Q. SHOULD A HYPOTHETICAL CAPITAL STRUCTURE BE CONSIDERED FOR THE COMPANY IN THIS INSTANCE?

A. No, it should not. The factors typically considered relative to the use of a regulated subsidiary's actual or expected capital structure, or a hypothetical capital structure, are provided by David C. Parcell in The Cost of Capital – A Practitioner's Guide ("CRRA Guide") prepared for the Society of Utility and Regulatory Financial Analysts ("SURFA") and provided as the study guide to candidates for SURFA's Certified Rate of Return Certification Examination. The CRRA Guide notes that there are circumstances where a hypothetical capital structure is used in favor of an actual or expected capital structure. They are:

(i) The utility's capital structure is deemed to be substantially different from the typical or "proper" utility capital structure; or

(ii) The utility is funded as part of a diversified organization whose overall capital structure reflects its diversified nature rather than its utility operations only.[8]

Phillips echoes the CRRA Guide when he states:

> Debt ratios began to rise in the late 1960s and early 1970s, and the financial condition of the public utility sector began to deteriorate. It became the common practice to use actual or expected capitalizations; actual where a historic test year is used, expected when a projected or future test year is used. (footnote omitted)

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6 OCA St. 3, at p. 60.

7 CAUSE-PA St. No. 1, at pp. 44-46.

8 David C. Parcell, The Cost of Capital – A Practitioner's Guide, Prepared for the Society of Utility and Regulatory Financial Analysts, 2020 Edition, p. 47.

> The objective, in short, shifted from minimization of the short-term cost of capital to protection of a utility's ability "to raise capital at all times. This objective requires that a public utility make every effort to keep indebtedness at a prudent and conservative level." (footnote omitted)
>
> *A hypothetical capital structure is used only where a utility's actual capitalization is clearly out of line with those of other utilities in its industry or where a utility is diversified.* (footnote omitted) (italics added)[9]

Similarly, the use of an operating subsidiary's capital structure is consistent with the approach found in Federal Energy Regulatory Commission ("FERC") precedent, under which they use the applicant's capital structure, where possible.[10] In particular, the FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees ; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by FERC.[11] Regarding the first two criterion, the Company issues its own debt and has a long-term issuer rating from Moody's of A3. As to the Company's actual equity ratios as compared to equity ratios authorized by regulatory commissions, I have provided a scatterplot of authorized equity ratios for natural gas utilities since 2020. As can be seen from Chart 1, below, the Company's actual equity ratio is within the range of authorized equity ratios of other natural gas utilities and should be deemed reasonable.

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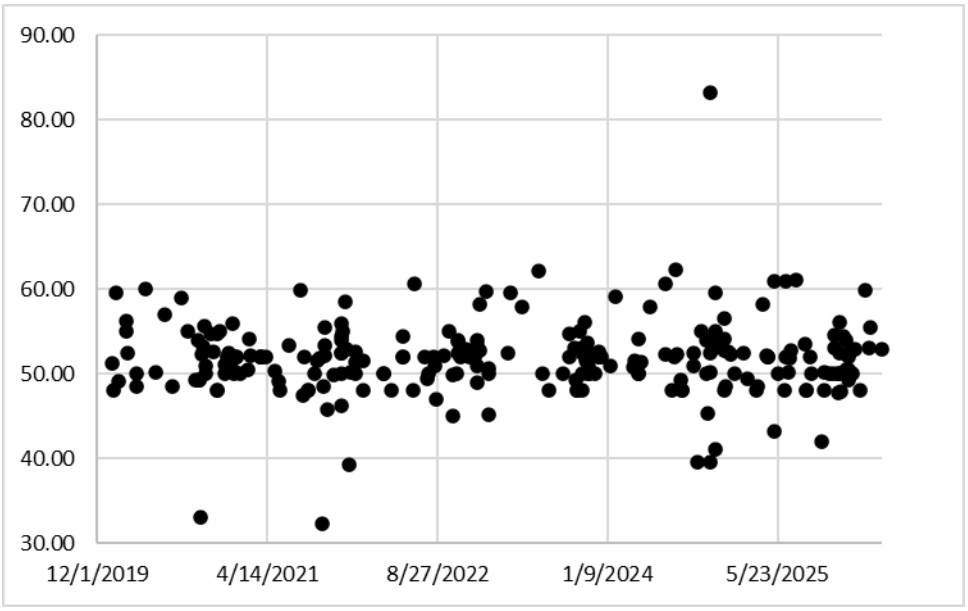
9 Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, at 391.

10 *See, Transcontinental Gas Pipe Line Corp,* 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

11 148 FERC ¶ 61,049, Docket No. EL14-12-000, at 190.

Chart 1: Authorized Equity Ratios for Natural Gas Utilities – 2020 to Present[12]



As the Company's capital structure is within the range of typical utilities, as represented by the Utility Proxy Group and their operating subsidiaries, and within the range of equity ratios authorized by utility regulatory commissions, a hypothetical capital structure should not be considered for the Company at this time.

Q. MR. BREUNING AND MR. GARRETT REFER TO THE AVERAGE EQUITY RATIOS OF THEIR PROXY GROUPS AS A BENCHMARK FOR AN APPROPRIATE EQUITY RATIO FOR THE COMPANY.[13] DO YOU AGREE WITH THEM?

A. No, I do not. As noted in my Direct Testimony,[14] the cost of capital is an opportunity cost, where investors decide between a basket of alternatives with comparable risk. The Utility Proxy Group represents alternative investments, which would mean that the range of equity ratios maintained by that group would be the benchmark for a reasonable equity ratio, not

12 Source of information: Regulatory Research Associates
13 I&E St. No. 2, at pp. 12; OCA St. 3, at p. 52.
14 UGI Gas St. No. 8, at p.7-8.

the average, as theoretically, every member of the Utility Proxy Group would be considered an alternative investment to the Company.

Q. MR. BREUNING SUGGESTS THAT THE COMMISSION CONSIDER RECOGNIZING THE COMPANY'S ABOVE AVERAGE EQUITY RATIO WHEN CONSIDERING THEIR FINANCIAL RISK IN THIS PROCEEDING.[15] HAVE YOU COMPARED THE COMPANY'S FINANCIAL RISK WITH THE UTILITY PROXY GROUP IN YOUR ANALYSIS?

A. Yes, I have. As discussed in my Direct Testimony, bond ratings reflect a company's combined business and financial risk (excluding size).[16] As shown on page 15 of Schedule DWD-1R, the Company's Moody's long-term issuer rating of A3 is equivalent to the Utility Proxy Group average long-term issuer rating, indicating similar combined business and financial risk (excluding size). Mr. Breuning's concern should be dismissed.

Q. MR. GARRETT REFERS TO THE DEBT LEVELS OF INDUSTRIES THAT ARE "RELATIVELY COMPARABLE" TO PUBLIC UTILITIES.[17] DO YOU AGREE WITH THAT COMPARISON?

A. No, I do not. In assessing the Company's capital structure, Mr. Garrett reviews the debt ratios of what he determines to be comparative industries. In his comparisons of the capital structures of non-regulated industries to UGI Gas, he does not evaluate the industries' market risk in comparison to the Company. If Mr. Garrett evaluated the market risk (i.e., unadjusted beta coefficients) of those industries, he would have found that those industries are not comparable in risk to utility companies like UGI Gas. Using Mr. Garrett's own

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15 I&E St. No. 1, at p. 17.
16 UGI Gas St. No. 8, at p. 11.
17 OCA St. 3, at pp. 54-55.

source, Dr. Damodaran,[18] the average unadjusted beta coefficients of the Cable TV industry (0.74), the Power industry (0.48), and the Telecom industry (0.63) are not comparable to the Utility (General) unadjusted beta coefficient of 0.24 and as such, those industries' capital structures should not be used as a comparator to the Company's actual capital structure.

Q. ARE THERE OTHER STATEMENTS MADE BY THE OPPOSING WITNESSES REGARDING THE APPROPRIATE CAPITAL STRUCTURE THAT YOU DEEM INCORRECT OR UNSUPPORTED?

A. Yes. I do not believe that the following statements are correct or supported: (1) that a capital structure containing 50.00% long-term debt and 50.00% equity is an "optimal" capital structure;[19] and (2) the contention that the Company's parent, UGI Corporation ("UGI"), is engaging in double leverage.[20]

Q. DO YOU AGREE WITH MR. BREUNING'S PRESUMPTION THAT A CAPITAL STRUCTURE CONTAINING 50.00% LONG-TERM DEBT AND 50.00% COMMON EQUITY IS THE "OPTIMAL" CAPITAL STRUCTURE?[21]

A. No, I do not. In fulfilling their obligation to serve, utilities make large, essentially irreversible investments that are recovered over decades at a compensatory cost of capital. Unlike unregulated entities, utilities generally do not have the option to delay, defer, or reject many large capital investments due to the utility's obligation to serve its customers. Because their operations are capital-intensive and meeting their service obligations is not discretionary, utilities generally do not have the option to avoid raising external funds

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18 https://pages.stern.nyu.edu/~adamodar/ accessed April 29, 2026.
19 I&E St. No. 2, at p. 14.
20 OCA St. 3, at pp. 55-56.
21 I&E St. No. 2, at p. 14.

during periods of capital market distress. Those conditions make capital structure optimization both dynamic and complex and does not lend itself to a one-size-fits-all approach as posited by Mr. Breuning.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN "MINIMIZING" AND "OPTIMIZING" FINANCING COSTS.

A. The optimal capital structure recognizes that there are numerous constraints associated with financing decisions, and minimizes financing costs subject to those constraints. In practice, financing constraints are dynamic in nature, in that they continually change in response to market conditions.

For example, in February 2021, the United States was impacted by Winter Storm Uri ("Uri"). Several members of the Utility Proxy Group were affected by Uri and were forced to raise significant amounts of debt to pay for exponentially increased costs of natural gas. Atmos Energy Corporation ("ATO") and ONE Gas, Inc. ("OGS") common equity percentages for the first quarter of 2021 were significantly impacted by their need to raise capital. Both ATO and OGS collectively were required to raise $4.7 billion in debt in response to Uri. The increased risk associated with this debt issuance was reflected in the rating agency's analysis. ATO was downgraded by S&P and its outlook was downgraded to negative by both S&P and Moody's, and OGS was downgraded and given negative outlooks by both agencies. Because ATO and OGS had strong balance sheets prior to this unanticipated need for debt, both companies had access to the capital markets and were able to maintain financial stability with the downgrades. Conversely, energy providers that did not have strong balance sheets had to file for Chapter 11 protection due to the exorbitant costs (e.g., Griddy Energy, Entrust, Just Energy, Brazos) and of those,

some were unable to serve their customers and were liquidated (e.g., Griddy Energy and Entrust).

As evidenced above, the factors that must be considered in making both day-to-day, and long-term financing decisions include the availability and cost of different forms of financing at a particular time, existing and expected capital market conditions (including the availability of capital, the terms at which capital may be acquired, and the ability to subsequently "roll over" maturing financings), the level of existing and proposed debt relative to rating agency criteria, cash flow contingencies, planned and existing capital spending plans, and lead times associated with changing from short-term to long-term financing. Only by considering all such factors can the issuing company establish an optimal financing plan and implement an optimal capital structure. Given this, a generic 50%/50% debt-to-equity capital structure cannot be considered optimal in all cases.

Q. MR. GARRETT DISCUSSES UGI CORPORATION'S USE OF DEBT TO DRIVE RETURNS AT THE EXPENSE OF ITS OPERATING SUBSIDIARIES SUCH AS UGI UTILITIES, INC.[22] WHAT IS YOUR RESPONSE?

A. Mr. Garrett's position appears to suggest the Company is engaging in double leverage, to the detriment of customers.[23] My primary concern is that Mr. Garrett's position runs counter to the widely accepted "stand-alone" regulatory principle, which treats each utility subsidiary as its own company. Under the stand-alone approach, the cost of capital is determined using the subsidiary's capital structure and cost of debt and equity. The cost of common equity is generally estimated by reference to a proxy group of firms of comparable risk.

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22 OCA St. 3, at pp. 5-6.
23 OCA St. 3, at pp. 5-6.

Consistent with the stand-alone principle as discussed previously, the ownership structure does not affect the operating utility's capital structure or cost of capital. Parent entities, like other investors, have capital constraints and must consider the attractiveness of the expected risk-adjusted return of each investment alternative as part of their capital budgeting process. This opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return on that financing must still be sufficient to provide an incentive to the parent entity to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with its affiliates and with other similarly situated utility companies.

From an external investor's perspective, the combined company must provide a return reflecting the risks of the company's constituent parts. Investors therefore value combined entities on a sum-of-the-parts basis, expecting each operating segment to provide its appropriate risk-adjusted return. That practical financial principle is consistent with the regulatory principle of treating utilities as stand-alone entities. From both perspectives, it is the utility's operating risk that defines the utility's capital structure and cost of capital, not investors' sources of funds.

Contrary to those basic principles, Mr. Garrett's double leverage argument assumes the required return depends on the source of financing, not on the risks of the underlying utility operations. The position that a company would have different cost rates depending on how its investors fund their equity investments violates the widely acknowledged economic "law of one price," which states that in an efficient market, identical assets would

have the same value.[24] In other words, two utilities, identical in all respects but for their form of ownership, should have the same common equity cost rates.

Moreover, if the common equity of a subsidiary were held by both the parent and an external investor, the equity held by the parent would have one required return, and the equity held by outside investors would have another. To the extent the required returns differ, so would the value of the equity. But in an efficient market, identical assets must have the same price (value). If not, the difference quickly would be arbitraged away. As Morin noted in New Regulatory Finance:

> Carrying the double leverage standard to its logical conclusion leads to even more unreasonable *prescriptions. If the common shares of a subsidiary were held by both the parent and by individual investors, the equity contributed by the parent would have one cost under the double leverage computation while the equity contributed by the public would have another.*[25]

The double leverage argument also requires every affiliate within the corporate family to have the same cost of capital, regardless of differences in risk. UGI Corp. contains subsidiaries that are both rate regulated and non-regulated. We can reasonably assume those subsidiaries face different risks. And because they face different risks, we reasonably may assume they require different returns. Morin further noted:

> Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to

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[24] N. Gregory Mankiw, *Principles of Economics* 381 (6th ed. Cengage Learning 2012).

[25] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 523 ("Morin").

common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different, and the double leverage adjustment shouldn't obscure this fact.[26]

Longstanding academic literature has thoroughly discussed the flaws associated with the double leverage approach. For example:

1. Pettway and Jordan (1983), and Beranek and Miles (1988) point out the flaws in the double leverage argument, particularly the excess return argument, and also demonstrate that the "stand-alone" method is the superior approach.[27]
2. Rozeff (1983) discusses the ratepayer cross-subsidies of one subsidiary by another when employing double leverage.[28]
3. Lerner (1973) concludes that the returns granted to equity investors must be based on the risks to which the investors' capital is exposed and not the investors' source of funds.[29]

Basic finance texts reach the same conclusions. In Principles of Corporate Finance, 8th edition, Brealey, Myers, and Allen state:

> In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is project risk that counts.[30]

Likewise, in Modern Corporate Finance, 1st edition, Shapiro states:

> Each project has its own required return, reflecting three basic elements: (1) the real or inflation-adjusted risk-free interest rate; (2) an inflation premium approximately equal to the amount of expected inflation; and (3) a premium for risk. The first two cost elements are shared by all projects and reflect

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26 Morin, at 524-525.

27 Richard H. Pettway and Bradford D. Jordan, *Diversification, Double Leverage, and the Cost of Capital,* The Journal of Financial Research, Vol. VI, No. 4, Winter 1983; William Beranek and James A. Miles, *The Excess Return Argument and Double Leverage,* The Financial Review, Vo. 23, No. 2, May 1988.

28 Michael S. Rozeff, *Modified Double Leverage – A New Approach*, Public Utilities Fortnightly, March 31, 1983.

29 Eugene M. Lerner, *What are the Real Double Leverage Problems?* Public Utilities Fortnightly, June 7, 1973.

30 Richard A. Brealey, Steward C. Meyers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

> the time value of money, whereas the third component varies according to the risks borne by investors in the different projects. For a project to be acceptable to the firm's shareholders, its return must be sufficient to compensate them for all three cost components. This minimum or required return is the project's cost of capital and is sometimes referred to as a hurdle rate.[31]

The preceding paragraph bears a crucial message: the cost of capital for a project depends on the riskiness of the assets being financed, not on the identity of the firm undertaking the project. Simply put, the notion of double leverage runs counter to both financial and regulatory principles.

Lastly, double leverage arguments have been rejected by several regulatory commissions, including the Maryland Public Service Commission:

> We reject People's Counsel's proposed capital structure [reflecting a double leverage adjustment] because it suffers from numerous flaws. First, it assumes that the rate of return depends on the source of capital rather than the risks faced by the capital.[32]

In 2016, the "FERC reiterated its previous position on "double leveraging,"[33] stating that "the motivations of a parent company are irrelevant"[34] so long as the operating company passes the FERC's three-part test: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the commission.[35] Under FERC guidance, the capital structure of UGI Corp. is not applicable to UGI Utilities, Inc.

The Washington Utilities and Transportation Commission has cited to FERC's position on the use of double leverage in support of its decision in Docket No. UE 050684:

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31 Alan C. Shapiro, Modern Corporate Finance, Wiley, 1st Ed., 1990, at 276.

32 Maryland Public Service Commission, Order No. 81517, Case No. 9092, *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rate and Charges for Electric Service and for Certain Rate Design Changes*, July 19, 2007, at 73. [Clarification added]

33 *See*, *Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997).

34 *See*, 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

35 *Ibid*. *See also*, *Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997).

> The FERC does not embrace the concept of double leverage. For purposes of calculating rate of return for wholly owned subsidiaries, FERC uses the stand-alone capital structure and return on equity of the subsidiary so long as the subsidiary issues its own debt, maintains its own credit ratings and meets other standards related to equity ratio. The courts have upheld this policy. See Missouri Pub. Serv. Comm'n v. Federal Energy Reg Comm'n, 215 F.3d 1, 342 U. S. App. DC. 1 (D.C. Cir. June 27, 2000).[36]

IV. RESPONSE TO I&E WITNESS BREUNING

Q. PLEASE SUMMARIZE MR. BREUNING'S RECOMMENDATIONS REGARDING THE OVERALL COST OF CAPITAL FOR THE COMPANY.

A. Mr. Breuning accepts UGI Gas's requested capital structure and cost of long-term debt.[37] Regarding the appropriate ROE for the Company, Mr. Breuning recommends a 9.81% ROE based on the average of his DCF result of 10.47%, his average CAPM result of 9.25%, and consideration of the national average of natural gas distribution authorized ROEs of 9.70%.[38]

Q. WHAT CONCERNS DO YOU HAVE WITH MR. BREUNING'S CONCLUSIONS AND RESULTS?

A. I have concerns with: (1) his significant departure from his and I&E's consistent exclusive reliance on the DCF model; (2) his application of the CAPM; (3) his consideration of historical authorized ROEs in his recommendation; (4) his failure to reflect the unique business risk of the Company; and (5) his failure to reflect flotation costs.

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36 Washington Utilities and Transportation Commission, Docket No. UE 050684, Order No. 4, at 117.
37 I&E St. No. 1, at pp. 14, 19.
38 I&E St. No. 1, at p. 7.

Q. HOW HAS MR. BREUNING CALCULATED HIS RECOMMENDED ROE IN THIS PROCEEDING?

A. As noted above, Mr. Breuning averages the results of his DCF (10.47%), his CAPM (9.25%), and the national average ROE (9.70%) to arrive at his recommended ROE of 9.81%. [39]

Q. WHAT APPROACH HAS I&E TRADITIONALLY USED IN DEVELOPING ITS RECOMMENDED ROE?

A. In my professional experience, I&E, to include Mr. Breuning, has always exclusively relied on the DCF model to inform their ROE recommendation, using the CAPM merely as a point of comparison to its DCF results. For example, in Docket No. R-2025-3053442, Mr. Breuning stated:

> I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I provide a CAPM analysis to be used as a comparison to, but not as a check of, the DCF results. The DCF method has the most wide-spread regulatory acceptance, and while the Commission has more recently based its ROE decisions on a combination of methods, I still recommend primary reliance on the DCF method due to the shortcomings associated with the CAPM method.[40]

Mr. Breuning states further in the same docket:

> The DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.[41]

Q. WHAT IS MR. BREUNING'S POSITION REGARDING THE DCF MODEL IN THIS PROCEEDING?

A. Mr. Breuning still contends that "the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for

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39 I&E St. No. 1, at p. 7.
40 Breuning Direct Testimony, Docket No. R-2025-3053442 – The York Water Company, at 19.
41 Breuning Direct Testimony, Docket No. R-2025-3053442 – The York Water Company, at 20.

the current economic market because it measures the cost of equity directly."[42] Mr. Breuning also notes in regard to the DCF result in my Direct Testimony that "Mr. D'Ascendis' average result of 10.53% is reasonable and almost identical to my DCF result of 10.47%."[43]

Q. DOES MR BREUNING DISCUSS WHY HE CHOSE TO USE THE CAPM IN HIS ANALYSIS?

A. Yes. Mr. Breuning states that he "included a CAPM analysis in my recommendation as it has been the Commission's recent desire to employ more than one ROE methodology,"[44] not that he believes in the value of the CAPM as a model.

Regarding the CAPM, Mr. Breuning himself opines that the CAPM is far less responsive to changes in the industry. Mr. Breuning also argues that: (1) the indicated ROE is only company-specific because of the use of the Beta coefficient ("beta"); (2) the model is historical in nature because beta is calculated using historical returns; and (3) empirical analysis by Fama and French show that the relationship between predicted return and actual return is poor.[45] From his own testimony in this case and in previous cases, it is clear that Mr. Breuning does not view the CAPM as a valid model to rely on for cost of capital purposes.

Q. HAS I&E GENERALLY RELIED ON AVERAGE AWARDED ROES IN THEIR ROE ANALYSIS HISTORICALLY?

A. No, they do not. In my experience in Pennsylvania, this is the first occurrence of I&E considering authorized ROEs in other jurisdictions to inform their ROE recommendation.

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42 I&E St. No. 1, at p. 23.
43 I&E St. No. 1, at p. 38.
44 I&E St. No. 1, at p. 24.
45 I&E St. No. 1, at pp. 25-26.

Q. WHAT IS THE IMPACT OF I&E'S SUDDEN CHANGE IN METHODOLOGY ON ITS RECOMMENDED ROE?

A. I&E's new approach substantially lowers I&E's recommendation. I&E's historical sole reliance on the DCF model would indicate an ROE of 10.47%, and its new approach indicates an ROE of 9.81%, a difference of 66 basis points. While I do agree that an ROE analysis should rely on multiple methods,[46] substantial errors in Mr. Breuning's application of the CAPM and his reliance on historical authorized ROEs without analysis as to their applicability and relevance to this proceeding serve to undermine and understate his ultimate recommendation, as will be discussed in detail below.

Q. DO YOU AGREE WITH MR. BREUNING'S REASONS FOR OMITTING THE RPM, AND COMPARABLE EARNINGS MODEL ("CEM") FROM HIS ANALYSIS?

A. No, I do not. Mr. Breuning excludes the RPM from his analysis because he claims that it is a simplified version of the CAPM**,** and subject to similar faults**,** in addition to not reflecting company-specific risks through the use of beta.[47]

Finally, Mr. Breuning omits a CEM analysis because he believes that the choice of comparable companies is highly subjective, and he does not believe that historical accounting returns are representative of future accounting returns.[48]

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46 UGI Gas St. No. 8, at p. 17-18.
47 I&E St. No. 1, at p. 21.
48 I&E St. No. 1, at p. 27.

Q. IS YOUR RPM ANALYSIS A SIMPLIFIED VERSION OF THE CAPM AND NOT COMPANY-SPECIFIC?

A. No, it is not. My beta-derived equity risk premium RPM analysis applies beta to the indicated equity risk premium to create a proxy group-specific equity risk premium.[49]

Q. IS YOUR CEM ANALYSIS CONSISTENT WITH MR. BREUNING'S DESCRIPTION?

A. No, it is not. The selection criteria for my Non-Price Regulated Proxy Group is not subjective in nature, as it is based on ranges of two measures of risk: (1) the unadjusted beta of the Utility Proxy Group, which measures systematic, or market risk; and (2) the standard error of the regression, which gave rise to those betas, measuring non-systematic or diversifiable risk. Systematic plus non-systematic risk is one definition of total risk.[50] This is agreed upon by Mr. Breuning, who states in his testimony: "two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta."[51]

Each company I selected for my Non-Price Regulated Proxy Group was required to have an unadjusted beta (a measure of systematic risk) and a standard error of the regression (a measure of unsystematic risk) within the ranges generated by my proxy group, as explained in pages 50 and 51 of my Direct Testimony and on Schedule DWD-7.

Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in

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49 UGI Gas St. No. 8, at pp. 28-29, and Schedule DWD-4.
50 Business risk plus financial risk is a second definition of total risk.
51 I&E St. No. 1, at p. 18.

Schedule DWD-2R. Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to my Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Schedule DWD-3R), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

Lastly, I apply the DCF, CAPM, and RPM to my Non-Price Regulated Proxy Group, which is an apples-to-apples comparison of the investor-required return for non-regulated companies similar in total risk, which makes Mr. Breuning's second concern regarding the CEM moot.

Q. HAVE YOU USED OTHER MEASURES OF TOTAL RISK TO COMPARE YOUR UTILITY PROXY GROUP AND YOUR NON-PRICE REGULATED PROXY GROUP?

A. Yes, I have. I compared the average and median *Value Line* Safety Ranking, the annualized volatility of stock returns, and the Coefficient of Variation ("CoV")[52] of net profit for the Utility Proxy Group and Non-Price Regulated Proxy Group, as shown on Table 3, below:

[52] The CoV, which is a measure of relative volatility, equals the standard deviation divided by the average.

Table 3: Comparison of Safety Rankings, CoV of Net Profit, and Annualized Volatility of Mr. D'Ascendis' Utility Proxy Groups and Non-Price Regulated Proxy Groups

Group	Average Safety Ranking	Median Safety Ranking	Median CoV Net Profit	Median Annualized Volatility
Utility Proxy Group	1.83	2.00	0.14	21.82%
Non-Price Regulated Proxy Group	1.54	2.00	0.21	23.00%

As shown, the Safety Rankings, annualized volatility of their stock returns, and CoV of net profit of the Utility Proxy Groups and the Non-Price Regulated Proxy Groups are comparable, indicating comparable total risk. This, in addition to all of the above, should lead the Commission to consider the results of my Non-Price Regulated Proxy Group as another measure of the Company's ROE in this proceeding.

A. Application of the DCF Model

Q. PLEASE SUMMARIZE MR. BREUNING'S DCF ANALYSIS AND HIS INDICATED RESULTS.

A. Mr. Breuning uses spot and 52-week average stock prices and current dividends to calculate the dividend yield and forecasted earnings per share ("EPS") growth rates to calculate his indicated DCF cost rate of 10.47%.[53]

Q. DO YOU HAVE ANY CONCERNS WITH MR. BREUNING'S APPLICATION OF THE DCF MODEL?

A. No, I do not. Mr. Breuning and I generally use the same inputs and form of the constant growth DCF model.

[53] I&E St. No. 1, at pp. 29-31.

B. Application of the CAPM

Q. PLEASE BRIEFLY SUMMARIZE MR. BREUNING'S CAPM METHODOLOGY AND RESULTS.

A. Mr. Breuning produces two CAPM analyses, both of which rely on the average *Value Line* beta of his proxy group. For the first CAPM analysis, he uses a projected 10-year Treasury yield for his risk-free rate and an average of an expectational market return and a historical 1926-2025 average market return to arrive at a CAPM result of 9.95%.[54] For his second CAPM analysis, he uses a historical 20-year Treasury yield and Kroll's recommended market risk premium ("MRP") to arrive at a result of 8.55%.[55] Mr. Breuning averages the results of his two CAPM analyses for a cost of equity of 9.25%.

Q. DO YOU HAVE ANY CONCERNS WITH MR. BREUNING'S APPLICATION OF THE CAPM?

A. Yes, I do. While I agree with Mr. Breuning's use of *Value Line* betas, projected interest rates, and projections of market returns, I have concerns regarding his selection of a risk-free rate, his use of Kroll's MRP, and his failure to conduct an ECAPM.

Q. IS THE USE OF 10-YEAR OR 20-YEAR TREASURY BONDS AS A RISK-FREE RATE APPROPRIATE FOR COST OF CAPITAL PURPOSES?

A. No, it is not. As discussed below, the tenor of the risk-free rate used in the CAPM should match the life (or duration) of the underlying investment. As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a

[54] I&E St. No. 1, at pp. 32-34.
[55] I&E St. No. 1, at p. 35.

> five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[56]

Morin also confirms this when he states:

> [b]ecause common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM (footnote omitted)… The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period.[57]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[58] As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to match that perpetual claim. The average life of UGI Gas's utility plant is approximately 39 years based on the composite depreciation rate of the components of its utility plant.[59] Thus, Mr. Breuning's use of a medium-term Treasury bond does not match the life of the assets being valued. The use of a 30-year Treasury bond is the more appropriate risk-free rate.

Q. MR. BREUNING CLAIMS THAT LONG-TERM GOVERNMENT BONDS ARE SUBJECT TO MATURITY RISK.[60] PLEASE COMMENT.

A. He is mistaken. If a long-term Treasury note is held to maturity, there is no risk (the investor will get the stated coupon rate and principal at the end). Since the cost of equity is a long-term concept, the investment horizon of an individual investor is irrelevant.

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56 Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.
57 Morin, at 169.
58 Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.
59 1 / 2.58% = 38.76
60 I&E St. No. 1, at p. 33.

Q. PLEASE DISCUSS MR. BREUNING'S PROJECTED RISK-FREE RATE.

A. Mr. Breuning and I use the same publication for our forecasted interest rate data, *Blue Chip Financial Forecasts* ("*Blue Chip*"). Mr. Breuning incorporates forecasts from the second quarter of 2026 out to the period 2027-2031, although forecasts are published by *Blue Chip* to the period 2032-2036. Mr. Breuning does not explain why he has omitted the 2032-2036 projection. Not incorporating the longest projection available is inconsistent with the application of the DCF model in which there is an assumption that the projected "g" is constant into perpetuity, creating a mismatch. It is also inconsistent with the Efficient Market Hypothesis ("EMH") on which the DCF is based.

Q. WHAT IS THE EMH?

A. According to Fama,[61] a market in which prices always "fully reflect" available information is called "efficient." There are three forms of the EMH, namely:

(1) The "weak" form asserts that all past market prices and data are fully reflected in securities prices. In other words, technical analysis cannot enable an investor to "outperform the market."

(2) The "semi-strong" form asserts that all publicly available information is fully reflected in securities prices. In other words, fundamental analysis cannot enable an investor to "outperform the market."

(3) The "strong" form asserts that all information, both public and private, is fully reflected in securities prices. In other words, even insider information cannot enable an investor to "outperform the market."

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[61] Eugene F. Fama. "Efficient Capital Markets: A Review of Theory and Empirical Work", *The Journal of Finance*, Vol. 25, No. 2. (May 1970), pp. 383-417.

The "semi-strong" form is generally considered the most realistic because the illegal use of insider information can enable an investor to "beat the market" and earn excessive returns, thereby disproving the "strong" form. The semi-strong form of the EMH assumes that all information (including long-term forecasts of interest rates) are available to the investor, which means the 2032-2036 forecasted interest rate would be considered by investors when making investment decisions and, therefore, should be included in Mr. Breuning's CAPM analysis.

Q. IS MR. BREUNING'S USE OF THE CURRENT 20-YEAR U.S. TREASURY YIELD IN HIS SECOND CAPM APPROPRIATE?

A. No, it is not. However, given that the current 20-year Treasury bond-based risk-free rate Mr. Breuning uses is reasonably consistent with the projected 30-year Treasury-bond based risk-free rate used in my updated CAPM, to reduce the scope of this Rebuttal Testimony, I will not address Mr. Breuning's use of a current risk-free rate as his error does not impact the outcome of the analysis in this case.

Q. IS MR. BREUNING'S CALCULATION OF HIS *VALUE LINE*-BASED MARKET RETURN CONSISTENT WITH OTHER ASPECTS OF HIS ROE ANALYSIS?

A. No, it is not. Mr. Breuning's estimate of the *Value Line* expected market return is based solely on the February 27, 2026 *Value Line Summary and Index* report. In his DCF analysis, he arrives at his final dividend yield by relying on an average of the spot dividend yield and the 52-week average dividend yield.[62] If Mr. Breuning believes that the spot dividend yield should be averaged with the 52-week average dividend yield in his DCF analysis, he should calculate his *Value Line* expected market return in a consistent manner.

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[62] I&E St. No. 1, at p. 34.

As shown on Schedule DWD-4R, page 2, doing so would result in an average *Value Line* expected market return of 11.36%, with an overall market return of 11.86%.

Q. WHAT IS YOUR POSITION ON THE 5.00% MRP QUOTED BY KROLL?

A. A forecast is only as good as its inputs, and if the assumptions within those forecasts are, by their nature, unpredictable (e.g., productivity growth forecasts), they are of little value. In addition, the determination of the MRP as calculated by Kroll is not transparent, especially in view of the historical data presented in Kroll's 2023 Stocks, Bonds, Bills, and Inflation Yearbook ("SBBI-2023"), or the composition of its supply side method, which are already well known by investors. Because of the transparency of the historical data and how to gather and use the components of the supply side model, both the historical MRP (using the long-term arithmetic mean return on large company stocks less the long-term arithmetic income returns on long-term Government bonds) and the supply side model are superior measures of the MRP, when compared to Kroll's simplistic and opaque MRP forecast.

Q. WHY IS THE KROLL MRP MORE OPAQUE THAN OTHER MEASURES OF THE MRP?

A. The MRP is calculated by subtracting a risk-free rate from the investor-required return on the market. Typically, the return on the market uses observable market measures (e.g. historical average returns), but the Kroll MRP does not define how they calculate their expected return on the market. Similarly, the risk-free rate is typically also based on market measures (e.g., historical interest rates, forecasted interest rates), but Kroll does not explain how they derive their 3.5% normalized risk-free rate. Because Kroll does not reveal how they derive their estimates, we do not know if they are indeed based on market measures.

Q. DID YOU CONDUCT A STUDY TO DETERMINE THE FORECAST ACCURACY OF THE KROLL RECOMMENDED MARKET RETURN RELATIVE TO THE HISTORICAL MARKET RETURN?

A. Yes, I did. I have calculated the forecast bias[63] of the long-term historical average return and the implied market returns from Kroll from 2008-2025 to determine the most accurate measure of the following years' market return.[64] For example, the long-term average market return from 1926-2008 was used to determine the forecasted return for 2009. The result of this analysis is shown as Schedule DWD-5R and Table 4, below:

Table 4: Comparison of Forecast Bias for Various Measures 2009-2025

Year	Observed Market Return	Long-Term Average Return	Kroll Forecasted Market Return
2009	26.46%	11.67%	10.50%
2010	15.06%	11.85%	10.08%
2011	2.11%	11.88%	9.63%
2012	16.00%	11.77%	10.00%
2013	32.39%	11.82%	9.50%
2014	13.69%	12.05%	9.00%
2015	1.38%	12.07%	9.00%
2016	11.96%	11.95%	9.50%
2017	21.83%	11.95%	9.00%
2018	-4.38%	12.06%	8.50%
2019	31.49%	11.88%	9.00%
2020	18.40%	12.09%	8.50%
2021	28.71%	12.16%	8.00%
2022	-18.11%	12.33%	8.00%
2023	26.61%	12.02%	10.14%
2024	25.62%	12.16%	10.03%
2025	18.06%	12.30%	10.06%
Sum	267.28%	204.01%	158.44%
Forecast Bias[65]		76.33%	59.28%

63 Forecast bias can be described as a tendency to either over-forecast or under-forecast a given variable.

64 2008 was selected as the starting year as it is the first year Kroll published its recommended MRP and risk-free rate.

65 Calculated by dividing the sum of the forecast returns by the sum of the actual returns.

As shown in Table 4, while both measures understate actual performance (i.e., forecast bias measures are under 100.00%), the long-term arithmetic mean return is the more accurate predictor of the next years' return as compared to the Kroll projected market return. This result is consistent with the work of economist John Y. Campbell, who states that when returns are serially uncorrelated, the arithmetic average represents the best forecast of future returns in any randomly selected future year.[66]

Q. MR. BREUNING DID NOT PERFORM AN ECAPM ANALYSIS. PLEASE COMMENT.

A. As discussed in my Direct Testimony,[67] although numerous tests of the CAPM have confirmed its validity, it has been determined that the empirical Security Market Line ("SML") described by the traditional CAPM is not as steeply sloped as the predicted SML. Tests of the CAPM have measured the extent to which security returns and betas are related as predicted by the CAPM, thus confirming its validity. As such, Mr. Breuning should have used the ECAPM in his CAPM analysis.

Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF THE ECAPM?

A. Yes, there is. The empirical issues with the CAPM have been present since the presentation of the model, as noted by Dianna R. Harrington in her text Modern Portfolio Theory & the Capital Asset Pricing Model:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the

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66 John Y. Campbell, "Forecasting US Equity Returns in the 21st Century," Social Security Administration, July 2001.

67 UGI Gas St. No.8, at pp. 31-32.

portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.

* * *

Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:

$$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$

Where:

R = total returns
β = the slope of the line (the incremental return for risk)
α = the intercept or a constant (expected to be 0 over time and across all firms)
ε = an error term (expected to be random, without information)
m = the market proxy
j = the firm or portfolio
t = the time period

Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable.

On the basis of the CAPM, they expected to find

1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)
2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformulation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-

free proxy, but did not find the evidence to support the other BJS conclusions.[68]

Harrington discusses Black's potential solution to this phenomenon:

> Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:
>
> $$E(R_i) = (1 - \beta_i) E(R_z) + \beta_i E(R_m)$$
>
> Where:
>
> E indicates expected,
> $E(R_z)$ is less than $E(R_m)$, and
> R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.
>
> Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for stocks with betas greater than one and too high for stocks with betas of less than one.[69]

As such, while I still find the CAPM to be appropriate, if Mr. Breuning is of the opinion that the CAPM is not reliable,[70] then he should have applied an ECAPM analysis.

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[68] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

[69] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 30-31.

[70] I&E St. No. 1, at p. 25, Breuning Direct Testimony, Docket No. R-2025-3053442 – The York Water Company, at 21-22.

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and North Carolina.[71]

Q. DOES MR. BREUNING HAVE CONCERNS REGARDING THE ECAPM?

A. Yes, he does. Specifically, Mr. Breuning claims that the ECAPM "does not increase the validity of the result"[72] but he fails to provide evidence to that effect. Conversely, I have provided substantial evidence that the ECAPM is a necessary adjustment to the CAPM in my Direct Testimony[73] and above. Mr. Breuning's unsupported concerns should be dismissed.

Q. WHAT WOULD MR. BREUNING'S CAPM RESULTS INDICATE IF CORRECTED TO REFLECT A FULLY FORECASTED 30-YEAR TREASURY

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71 The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

72 I&E St. No. 1, at p. 40.

73 *See* UGI Gas St. No. 8, at pp. 31-33.

BOND YIELD, A *VALUE LINE* MARKET RETURN CALCULATED IN A MANNER CONSISTENT WITH HIS DCF, AND THE USE OF THE ECAPM?

A. As shown in Schedule DWD-4R, using a fully projected 30-year Treasury bond yield, a *Value Line* market return based on the average of the spot expected return and 52-week average expected return, and employing the ECAPM would result in an indicated ROE of 10.49%.

C. Relevance of Authorized Returns

Q. DOES MR. BREUNING GIVE JUSTIFICATION FOR CONSIDERING AUTHORIZED NATURAL GAS ROES IN HIS ANALYSIS?

A. Yes. He claims that because "a utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties", he believes that "it is reasonable and logical to include in my recommendation the authorized returns of the Company's peers in recently completed rate cases across the country."[74]

Q. ARE HISTORICAL ROES A GOOD MEASURE OF PROSPECTIVE ROES?

A. While authorized ROEs may be reasonable benchmarks of acceptable ROEs in static economic conditions, they can mis-specify the investor-required return in a dynamic economic environment. The reason why historical authorized returns mis-specify the investor-required return in changing markets is because authorized ROEs are a lagging indicator of investor-required returns; i.e., authorized ROEs are based on market data presented in an evidentiary record, which spans a period before the decision, lasting over a year in some cases. Because markets are constantly changing, historical authorized returns do not completely reflect the investor required return because the economic conditions in the past are not representative of economic conditions now. That is, what

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74 I&E St. No. 1, at p. 37.

investors require in the future may not correlate to what they required and/or received in the past. We must remember that projecting the investor required ROE is a forward-looking concept. Because this is the case, Mr. Breuning's observations regarding historically allowed ROEs are of little value.

Q. IS THERE A WAY TO USE HISTORICAL AUTHORIZED RETURNS TO DERIVE A MEASURE OF THE INVESTOR REQUIRED RETURN?

A. Yes, there is. A useful way to use historical authorized ROEs for cost of capital purposes would be to determine whether a relationship between authorized ROEs (or equity risk premiums ("ERP")) and interest rates exists so one can determine an expectational ROE or ERP given an interest rate. Studies by Harris and Marston (2001) and Brigham, Dilip, Shone, and Vinson (1985) indicate an inverse relationship between ERPs and interest rates (i.e., as interest rates move, ERPs move in the opposite direction, but not to the extent of the interest rate move).

As shown on Schedule DWD-6R, using historical authorized ROEs and interest data in regression analyses produces statistically significant inverse relationships between interest rates and ERPs, which can be used to determine expectational investor-required returns. Given an expectational A2-rated Public Utility bond yield of 5.68%, an indicated ERP of 4.85% is calculated using Mr. Breuning's natural gas historical ROE data. Adding the expectational A2-rated public utility bond yield to the ERP results in an indicated ROE of 10.53%.

Q. WHAT WOULD MR. BREUNING'S INDICATED ROE BE IF HE AVERAGED HIS DCF MODEL RESULT WITH THE CORRECTED CAPM AND RPM RESULTS OF 10.49% AND 10.53%, RESPECTIVELY?

A. It would be 10.50%, which is within my updated range of ROEs attributable to my Utility Proxy Group. However, Mr. Breuning's corrected average indicated ROE does not reflect Company-specific factors, which will be discussed in detail below.

D. Failure to Reflect the Company's Greater Relative Risk Due to its Smaller Size

Q. DOES MR. BREUNING MAKE A SPECIFIC ADJUSTMENT TO REFLECT THE SMALLER SIZE OF THE COMPANY RELATIVE TO HIS PROXY GROUP?

A. No. As discussed in my Direct Testimony,[75] relative company size is a significant element of business risk for which investors expect to be compensated through greater returns. Smaller companies are simply less able to cope with significant events which affect sales, revenues and earnings. For example, smaller companies face more exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few large customers would have a far greater effect on a smaller company than on a larger company with a more diverse customer base. Finally, smaller companies are generally less diverse in their operations and have less financial flexibility. Consistent with the financial principle of risk and return in my Direct Testimony,[76] such increased risk due to smaller size must be taken into account in the allowed rate of return on common equity.

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75 UGI Gas St. No. 8, at pp. 54-60.
76 UGI Gas St. No. 8, at p. 11.

Q. DOES MR. BREUNING RELY ON STUDIES THAT SUPPORT THE SMALL SIZE PREMIUM?

A. Yes. In the Fama and French article cited by Mr. Breuning in his direct testimony,[77] the authors propose that their three-factor model include the "Small Minus Big" factor, which indicates that small capitalization firms are more risky than large capitalization firms,[78] confirming that size is a risk factor which must be taken into account in estimating the cost of common equity.

Q. MR. BREUNING RELIES ON A STUDY BY DR. ANNIE WONG FOR THE PROPOSITION THAT THERE IS NO SIZE PREMIUM FOR UTILITIES.[79] PLEASE COMMENT.

A. Mr. Breuning relies on the Wong Study to refute my position that the size adjustment is applicable to utilities, despite evidence to the contrary from Zepp as cited in my Direct Testimony (addressed in pages 56 through 59 of my Direct Testimony). Mr. Breuning also did not provide any rebuttal to the low level of explanatory power (i.e., R-Squared) in Beta coefficients that would be used in Wong's size study or my studies showing a link between size and risk for utility companies. The Commission should disregard Mr. Breuning's arguments that there is no size premium for utilities.

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77 *See* I&E St. No. 1, at p. 26.

78 Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004, at 39.

79 I&E St. No. 1, at p. 46.

Q. MR. BREUNING POINTS TO THE COMMISSION'S DECISION AT DOCKET NO. R-2019-3008212 AND NOTES THAT THE COMMISSION DID NOT MAKE AN EXPLICIT SIZE ADJUSTMENT.[80] PLEASE COMMENT.

A. While the Commission did not make an explicit size adjustment in that proceeding, it did acknowledge that size is a factor in assessing a company's ability to attract capital (i.e., the cost required by investors).[81] Specifically, the Commission adjusted the DCF result by one standard deviation of the mean and median to account for size. Applying that same approach in my Direct Testimony resulted in a size premium of 1.51%, higher than my ultimate recommendation, making my proposed size adjustment conservative.[82]

Q. HAVE YOU CALCULATED THE STANDARD DEVIATION OF MR. BREUNING'S DCF RESULTS?

A. Yes, I have. As put forth in Schedule DWD-7R, using data from Mr. Breuning's Exhibits, I have calculated a 37-basis-point standard deviation for his DCF results. This indicated business risk adjustment is higher than my recommended business risk adjustment, suggesting that my adjustment should be considered conservative, and should continue to be considered by the Commission when determining the appropriate ROEs for the Company in this proceeding.

E. <u>Flotation Cost Adjustment</u>

Q. DOES MR. BREUNING CONSIDER A FLOTATION COST ADJUSTMENT?

A. No, he does not. Mr. Breuning does not propose a flotation cost adjustment to the ROE and claims that flotation costs should be recovered as an operating expense.[83] Denying

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80 *See* I&E St. No. 1, at p. 48.
81 UGI Gas St. No. 8, at pp. 60-61.
82 UGI Gas St. No. 8, at p. 44.
83 I&E St. No. 1, at p. 50-51.

recovery of issuance costs penalizes the investors that fund the utility operations. As shown in page 2 of Schedule DWD-11 of my Direct Testimony, because of flotation costs, an authorized return of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.65% (i.e., below the required return).[84]

Q. HAVE OTHER REGULATORY COMMISSIONS ALLOWED FLOTATION COSTS IN THE ALLOWED ROE?

A. Yes, they have. For example, in Peoples Gas System, Inc.'s ("PGS") 2023 rate proceeding, the Florida Public Service Commission stated the following regarding my proposed flotation cost adjustment:

> In PGS's last rate case in 2008, we did not make a specific adjustment for flotation costs, but in our order we stated that we have traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor required return...We find witness D'Ascendis's method to determine the flotation cost is credible and provided persuasive evidence for his recommendation to include a flotation cost of 9 basis points.[85]

Given the above, I recommend this Commission also correctly include flotation costs in the allowed ROE.

F. Response to Mr. Breuning's Criticisms of Company Testimony

Q. DOES MR. BREUNING HAVE CRITIQUES OF THE ANALYSES MADE IN YOUR DIRECT TESTIMONY?

A. Yes. Mr. Breuning has the following critiques of my analyses in my Direct Testimony: (1) that I have given weight to the ECAPM and Risk Premium models in my determination of the ROE for the Company; (2) that the predictive risk premium model ("PRPM") is not

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[84] Direct Schedule DWD-10 is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

[85] *In re: Petition for rate increase by Peoples Gas System, Inc.*, Docket No. 20230023-GU, Order Granting in Part and Denying in Part Peoples Gas System, Inc.'s Petition for a Rate Increase, at 68 (December 27, 2023).

commonly used or accepted; (3) that I rely on the 30-year Treasury bond in my CAPM analysis; (4) that my selection and use of a Non-Price Regulated Proxy Group similar in total risk to my Utility Proxy Group is "speculative and subjective";[86] (5) that the size adjustment I use is not applicable to utility companies; and (6) that flotation costs should not be recovered through an adjustment to the ROE.

As I addressed critiques (1), (3), (4), (5), and (6) in my response to Mr. Breuning's analyses, I will not address them again here. I will address the remaining critiques in turn.

Q. MR. BREUNING SAYS THAT THE PRPM WAS PUBLISHED IN 2011.[87] DOES THAT MEAN THAT THE METHODOLOGY BEHIND THE PRPM WAS ALSO PUBLISHED IN 2011?

A. No. As discussed in my Direct Testimony,[88] the PRPM is based on the research of Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns and risk premiums clusters over time, making prices, returns and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as "methods of analyzing economic time series with time-varying volatility ("ARCH")."[89] Dr. Engle[90] noted that relative to volatility, "the standard tools have become the ARCH / GARCH[91] models." Hence, the methodology is <u>not</u> new.

In addition, the GARCH methodology has been well tested by academia, since Engle's, *et al*. research was originally published in 1982, over 40 years ago. I use the well-established GARCH methodology to estimate the PRPM model using a standard

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86 I&E St. No. 1, at p. 42.
87 I&E St. No. 1, at p. 39.
88 UGI Gas St. No. 8, at p. 26.
89 www.nobelprize.org.
90 Robert Engle, "GARCH 101: The Use of ARCH / GARCH Models in Applied Econometrics", *Journal of Economic Perspectives*, Volume 15, No. 4, Fall 2001, p. 157-168.
91 Autoregressive Conditional Heteroskedasticity / Generalized Autoregressive Conditional Heteroskedasticity.

commercial and relatively inexpensive statistical package, Eviews,© to develop a means by which to estimate a predicted equity risk premium, that when added to a bond yield, results in a cost of common equity.

The PRPM is also in the public domain, having been published six times in academically peer-reviewed journals: Journal of Economics and Business (June 2011 and April 2015),[92] The Journal of Regulatory Economics (December 2011),[93] The Electricity Journal (May 2013 and March 2020),[94] and Energy Policy (April 2019).[95] Notably, none of these articles have been rebutted in the academic literature.

Finally, the PRPM was presented to a number of utility industry/regulatory/academic groups including the following: The Edison Electric Institute Cost of Capital Working Group; The NARUC Staff Subcommittee on Accounting and Finance; The National Association of Electric Companies Finance/Accounting/Taxation and Rates and Regulations Committees; the NARUC Electric Committee; The Wall Street Utility Group; the Indiana Utility Regulatory Commission Cost of Capital Task Force; the Financial Research Institute of the University of Missouri Hot Topic Hotline Webinar; and the Center for Research and Regulated Industries Annual Eastern Conference on two occasions.

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92 Eugene A. Pilotte and Richard A. Michelfelder, "Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing", *Journal of Economics and Business*, June 2011, 582-604; and Richard A. Michelfelder, "Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital", *Journal of Economics and Business*, April 2015, 37-50.

93 Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "New Approach to Estimating the Equity Risk Premium for Public Utilities", *The Journal of Regulatory Economics*, December 2011, at 40:261-278.

94 Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity", The Electricity Journal, April 2013, at 84-89; and Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling, Risk Impacts and the Cost of Capital", *The Electricity Journal,* January 2020.

95 Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, "Decoupling Impact and Public Utility Conservation Investment", *Energy Policy*, April 2019, 311-319.

Q. HAS THE PRPM BEEN IMPLICITLY ACCEPTED BY OTHER REGULATORY COMMISSIONS?

A. Yes. In Docket No. 2017-292-WS, the Public Service Commission of South Carolina ("PSC SC") accepted Carolina Water Services' entire requested ROE, which included the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[96]

In addition, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission ("NCUC") approved my RPM and CAPM analyses, which used PRPM analyses as presented in this proceeding.[97]

Q. MR. BREUNING POSITS THAT YOU USE PROPRIETARY SOFTWARE TO CONDUCT YOUR PRPM.[98] IS THAT CORRECT?

A. No. The GARCH methodology is available in various statistical packages such as EViews®, SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive and provide instructions for using the various statistical methodologies in their software. I provided all parties in these proceedings with the backup data to run their own GARCH models. While the software I

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96 PSC SC Docket No. 2017-292-WS - Order No. 2018-345, at 14. (May 17, 2018).

97 NCUC Docket No. W-354, Sub 363, 364, 365, *Order Granting Partial Rate Increase and Requiring Customer Notice*, at PDF 72 (March 31, 2020).

98 I&E St. No. 1, at p. 39.

used in this proceeding costs approximately $2,450 for a single user commercial license,[99] JMulti is a free downloadable software with GARCH estimation applications.

V. RESPONSE TO OCA WITNESS GARRETT

Q. PLEASE PROVIDE A SUMMARY OF MR. GARRETT'S ANALYSES AND RECOMMENDATIONS REGARDING UGI GAS'S OVERALL COST OF CAPITAL.

A. Mr. Garrett applies two DCF models (analyst's growth and sustainable growth) and two CAPM analyses (traditional and Hamada), which produce a range of results from 7.60% to 8.80%. While he accepts the Company's proposed long-term debt cost rate, he rejects the Company's proposed capital structure in favor of a hypothetical capital structure consisting of 51.00% equity and 49.00% long-term debt.[100] If his proposed capital structure is accepted, Mr. Garrett recommends an 8.80% ROE, which is the result of his traditional CAPM.[101] If the Commission accepts UGI Gas's proposed capital structure, he recommends an 8.50% ROE based on his Hamada CAPM.[102]

Q. IN WHAT KEY AREAS ARE YOU CONCERNED WITH MR. GARRETT'S ANALYSES AND RECOMMENDATIONS?

A. There are several areas in which I have concerns with Mr. Garrett's analyses and conclusions, including: (1) his recommended capital structure; (2) his application of the DCF model; (3) his application of the CAPM; (4) his failure to reflect the unique business risk of the Company; and (5) his failure to reflect flotation costs incurred by the Company. As it appears that Mr. Garrett places no weight on his DCF model results in arriving at his

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99 http://www.eviews.com/general/prices/prices.html
100 OCA St. 3, at p. 3.
101 OCA St. 3, at p. 3.
102 OCA St. 3, at p. 3.

recommendation in this proceeding, I will not address his application of the DCF model at this time. If, in subsequent testimony, Mr. Garrett states he indeed relied on his DCF model for his recommendation, I will address his application of the DCF model at that time.

A. Application of the CAPM

Q. PLEASE SUMMARIZE MR. GARRETT'S CAPM ANALYSES AND RESULTS.

A. Mr. Garrett's primary CAPM estimate relied on a risk-free rate of 4.82%, an MRP of 5.10%, and betas as reported by *Value Line*. Those assumptions combined to produce an average CAPM estimate of 8.80%.[103] Mr. Garrett also conducts a Hamada CAPM using the same risk-free rate and MRP, but re-levers the *Value Line* beta to reflect the average equity ratio of his proxy group.[104]

Q. DO YOU AGREE WITH MR. GARRETT'S APPLICATION OF THE CAPM?

A. No, I do not. My primary concerns are Mr. Garrett's selection of his MRP and that he does not employ the ECAPM. I generally do not agree with the use of current interest rates for cost of capital purposes, but the difference between measures of our risk-free rates are immaterial at this time. I also disagree with the applicability of his Hamada CAPM as described in detail below.

Q. HOW DID MR. GARRETT DERIVE HIS MRP ESTIMATE?

A. Mr. Garrett derived his MRP estimate based upon the following: (1) a survey of expected returns from IESE Business School (5.50%); (2) an expected return reported by Kroll (Duff & Phelps) (5.00%); (3) implied MRP from Damodaran (5.00%); and (4) an "Implied Equity Risk Premium" calculation (5. 00%).[105] Based on those results, Mr. Garrett concludes that 5.10%, the average of his range, is appropriate.

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103 Exhibit DJG-11.
104 OCA St. 3, at pp. 56-58.
105 OCA St. 3, at p. 37; Exhibit DJG-10.

Q. WHAT IS YOUR POSITION ON THE 5.00% MRP QUOTED BY KROLL?

A. As discussed previously, the Kroll MRP is opaque as compared to Kroll's historical data, and less accurate, and as such should be afforded little weight.

Q. DO ANY OF THE SURVEYS CITED BY MR. GARRETT PROVIDE SUPPORT FOR YOUR APPROACH TO ESTIMATING THE CURRENT MRP?

A. Yes. As discussed in my Direct Testimony,[106] I calculated ex-ante MRPs in a similar manner to a study by Pablo Fernandez, et al (cited by Mr. Garrett), using the market capitalization-weighted constant growth DCF calculation on the individual companies in the S&P 500 Index.[107]

Q. IS THERE ACADEMIC LITERATURE THAT SUPPORTS THE CONCLUSION THAT MRPS USING SURVEYS ARE NOT WIDELY USED BY PRACTITIONERS?

A. Yes. Damodaran, who was cited by Mr. Garrett throughout his testimony, states the following about the applicability of survey MRPs:

> While survey premiums have become more accessible, very few practitioners seem to be inclined to use the numbers from these surveys in computations and there are several reasons for this reluctance:
>
> 1. Survey risk premiums are responsive to recent stock price movements, with survey numbers generally increasing after bullish periods and decreasing after market decline. Thus, the peaks in the SIA survey premium of individual investors occurred in the bull market of 1999, and the more moderate premiums of 2003 and 2004 occurred after the market collapse in 2000 and 2001.

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106 UGI Gas St. No. 8, at pp. 48-49.

107 *See*, Pablo Fernandez, Eduardo de Apellaniz and Javier F. Acin, *Survey: Market Risk Premium and Risk-Free Rate used for 81 countries in 2020*, IESE Business School, March 25, 2020, at 10. Specifically, the study states:[t]he [implied equity premium] is the implicit [required equity premium] used in the valuation of a stock (or market index) that matches the current market price. The most widely used model to calculate the [implied equity premium] is the dividend discount model: the current price per share (P_0) is the present value of expected dividends discounted at the required rate of return (K_e). If d_1 is the dividend per share expected to be received in year 1, and g the expected long-term growth rate in dividends per share,

$P_0 = d_1 / (Ke - g)$, which implies:[implied equity premium] = $d_1/P_0 + g - R_f$

2. Survey premiums are sensitive not only to whom the question is directed at but how the question is asked. For instance, individual investors seem to have higher (and more volatile) expected returns on equity than institutional investors and the survey numbers vary depending upon the framing of the question.[footnote omitted]. Kaustia, Lehtoranta and Puttonen (2011) surveyed 1,465 Finnish investment advisors and note that not only are male advisors more likely to provide an estimate but that their estimated premiums are roughly 2% lower than those obtained from female advisors, after controlling for experience, education and other factors.[footnote omitted]

3. Studies that have looked at the efficacy of survey premiums indicate that if they have any predictive power, it is in the wrong direction. Fisher and Statman (2000) document the negative relationship between investor sentiment (individual and institutional) and stock returns.[footnote omitted] In other words, investors becoming more optimistic (and demanding a larger premium) is more likely to be a precursor to poor (rather than good) market returns.

As technology aids the process, the number and sophistication of surveys of both individual and institutional investors will also increase. However, it is also likely that these survey premiums will be more reflective of the recent past rather than good forecasts of the future.[108]

Q. PLEASE DESCRIBE THE METHOD BY WHICH MR. GARRETT CALCULATED HIS THIRD ESTIMATE, THE IMPLIED MRP.

A. As Mr. Garrett points out, his method developed the Internal Rate of Return that sets the current value of the market index equal to the projected value of cash flows associated with owning the market index.[109] Mr. Garrett observes that Damodaran "promotes the implied ERP method."[110] Although there are some differences, Mr. Garrett's approach is similar to the model Damodaran provides on his website.[111]

Mr. Garrett's method, which is a two-stage form of the DCF model, calculated the present value of cash flows over the five-year initial period, together with the terminal price

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108 Aswath Damodaran, Stern School of Business, *Equity Risk Determinants, Estimation and Implications – The 2025 Edition*, Updated March 5, 2025, at 30-31.

109 OCA St. 3, at pp. 34-37.

110 OCA St. 3, at p. 37.

111 *See*, http://pages.stern.nyu.edu/~adamodar.

(based on the Gordon Model [112]), to be received in the last (i.e., fifth) year. The model's principal inputs include the following assumptions:

- Over the coming five years, the S&P 500 Index (the "Index") will appreciate at a rate equal to the compound growth rate in "Operating Earnings" from 2014 through 2024;
- Cash flows associated with owning the Index will be equal to the historical average earnings, dividends, and buyback yields, applied to the projected Index value each year; and
- Beginning in the terminal year, the Index will appreciate, in perpetuity, at a rate equal to the 30-day average yield on 30-year Treasury securities, as of April 2, 2026.[113]

As discussed below, reasonable changes to those assumptions have a considerable effect on Mr. Garrett's calculated expected market return.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING MR. GARRETT'S ASSUMED FIRST-STAGE GROWTH RATE?

A. Yes. Mr. Garrett's 6.95% growth rate relates to growth in operating earnings, and does not reflect capital appreciation, growth in dividends, or buy-backs.[114] In addition, if Mr. Garrett's position is that historical growth rates are meant to reflect expected future growth, they should reflect year-to-year variation (i.e., uncertainty). That is best accomplished using the arithmetic mean. I therefore calculated the average growth (arithmetic mean) for the four metrics included in Mr. Garrett's exhibit as shown in page 2 of Schedule DWD-

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112 Exhibit DJG-9

113 Exhibits DJG-7 and DJG-9. The model also assumes that all payments are received at year-end, rather than during the year. That assumption also tends to under-state the implied MRP.

114 Exhibit DJG-9. Whereas the compound average growth rate in operating earnings was 6.95%, dividends and buybacks grew by 6.08% and 9.00%, respectively.

8R. The average growth rate, 9.04%, produced an estimated market return of 10.28%,[115] which is still well below historical experience.

Q. WHY DID THE MARKET RETURN INCREASE BY ONLY 46 BASIS POINTS (FROM 9.83% TO 10.28%) WHEN THE FIRST-STAGE GROWTH RATE INCREASED BY 208 BASIS POINTS (FROM 6.95% TO 9.04%)?

A. Because Mr. Garrett's model assumed the first stage lasts for five years (and the terminal stage is perpetual), the results are sensitive to changes in the assumed terminal growth rate. To put that effect in perspective, the terminal value (which is directly related to the terminal growth rate) represents 78.94% of the "Intrinsic Value" in Mr. Garrett's analysis.[116]

Q. HOW DID MR. GARRETT DEVELOP HIS ASSUMED TERMINAL GROWTH RATE?

A. The terminal growth rate represents investors' expectations of the rate at which the broad stock market will grow, in perpetuity, beginning in the terminal year. Mr. Garrett assumed terminal growth is best measured by the average yield on 30-year Treasury securities over the 30 days ended April 2, 2026. That is, Mr. Garrett assumed the average 30-year Treasury yield between February 20, 2026, and April 2, 2026, is the best measure of expected earnings growth beginning five years from now and extending indefinitely into the future.

Q. DO YOU AGREE WITH MR. GARRETT'S ASSUMPTION?

A. No, I do not. I recognize Mr. Garrett followed the approach described in Damodaran's method, which Damodaran refers to as a "default" assumption.[117] In terms of historical experience, over the long-term the broad economy has grown at a long-term compound

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115 Schedule DWD-8R, page 2.

116 Schedule DWD-8R, page 2. Please note that regardless of the assumed first and terminal-stage growth rates, the terminal stage consistently represents approximately 79.00% of the Intrinsic Value.

117 *See*, http://pages.stern.nyu.edu/~adamodar.

average growth rate of approximately 6.10%.[118] Considered from another perspective, Kroll reports the long-term rate of capital appreciation on Large Company stocks to be 8.27%.[119] Mr. Garrett's model assumes, however, that the market index will grow by a rate of about 199 basis points below that amount, 6.28%, over the coming four years.[120]

Mr. Garrett has not explained why growth beginning five years in the future, and extending in perpetuity, will be 58% of long-term historical growth.[121] From a somewhat different perspective, assuming long-term inflation will be approximately 2.00%[122] implies perpetual real growth will be approximately 2.76%.[123] Nowhere in his testimony has Mr. Garrett explained the fundamental, systemic changes that would so dramatically reduce long-term economic growth, or why they are best measured by the long-term Treasury yield over 30 days between February 20, 2026, and April 2, 2026.

Further, research by the Federal Reserve Bank of San Francisco calls into question the relationship between interest rates and macroeconomic growth. As the authors noted, "[o]ver the past three decades, it appears that private forecasters have incorporated essentially no link between potential growth and the natural rate of interest: The two data series have a zero correlation."[124]

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118 Source: Bureau of Economic Analysis for the years 1929 to 2025. *See also*, https://www.bea.gov/data/gdp/gross-domestic-product.

119 SBBI-2023, 137.

120 Exhibit DJG-9. (8555/6704)^(1/4) - 1 = 6.28%.

121 Garrett assumed perpetual growth rate of 4.89% divided by large company capital appreciation of 8.27%. 4.82% / 8.27% = 58.25%.

122 For example, in line with the Federal Reserve's target average rate of inflation.

123 2.76% = [(1.0482/1.020)-1]. Please note that the long-term historical average rate of inflation, measured by the difference between real and nominal GDP growth, has been approximately 2.90%, which would also imply perpetual real growth of 1.87%. Similarly, the projected difference in nominal GDP and real GDP from the Congressional Budget Office as reported in Exhibit DJG-5 has been approximately 2.20%, which implies perpetual real growth of 2.66%.

124 FRBSF Economic Letter, *Does Slower Growth Imply Lower Interest Rates?*, November 10, 2014, at 3.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RESPONSE TO MR. GARRETT'S IMPLIED EQUITY RISK PREMIUM CALCULATION.

A. Mr. Garrett's calculation is based on a series of questionable assumptions, to which a small set of very reasonable adjustments produces a market return estimate more consistent with (yet still below) the historical experience he considers relevant. Although the revised results still produce ROE estimates far below any reasonable measure, they do point out the sensitive nature of Mr. Garrett's analyses, and the tenuous nature of the conclusions he draws from them.

Q. DID YOU CONDUCT A STUDY TO DETERMINE THE FORECAST ACCURACY OF THE DAMODARAN AND THE FERNANDEZ SURVEY IMPLIED MARKET RETURNS RELATIVE TO THE HISTORICAL MARKET RETURNS?

A. Yes, I did. Similar to my analysis of the Kroll "recommended" market return, I have calculated the forecast bias of the long-term historical average return, and the implied market returns from Damodaran and the Fernandez Survey from 2008-2025 to determine the most accurate measure of the following years' market return.[125] The result of this analysis is also shown on Schedule DWD-5R and presented in Table 5, below:

[125] 2008 was selected as the starting year as it is the first year Kroll published its recommended MRP and risk-free rate.

Table 5: Comparison of Forecast Bias for Various Measures 2009-2025

Year	Observed Market Return	Long-Term Average Return	Damodaran Forecasted Market Return	Fernandez Forecasted Market Return
2009	26.46%	11.67%	8.64%	10.75%
2010	15.06%	11.85%	8.20%	10.25%
2011	2.11%	11.88%	8.49%	9.32%
2012	16.00%	11.77%	7.89%	7.96%
2013	32.39%	11.82%	7.54%	8.10%
2014	13.69%	12.05%	8.00%	8.81%
2015	1.38%	12.07%	7.95%	7.90%
2016	11.96%	11.95%	8.39%	7.60%
2017	21.83%	11.95%	8.14%	8.20%
2018	-4.38%	12.06%	7.49%	8.20%
2019	31.49%	11.88%	8.64%	8.30%
2020	18.40%	12.09%	7.12%	7.50%
2021	28.71%	12.16%	5.65%	7.30%
2022	-18.11%	12.33%	5.75%	8.30%
2023	26.61%	12.02%	9.82%	9.50%
2024	25.62%	12.16%	8.48%	9.60%
2025	18.06%	12.30%	8.91%	9.60%
Sum	267.28%	204.01%	135.10%	147.19%
Forecast Bias[126]		76.33%	50.55%	55.07%

As shown in Table 5, again, the long-term arithmetic mean return is the most accurate predictor of the next years' return as compared to the other measures, and the Damodaran and Fernandez projected market returns are less accurate measures of the market return. I will also note that the Damodaran and Fernandez projected market returns are even more understated than the Kroll projected market returns.

Q. DID MR. GARRETT CONDUCT AN ECAPM ANALYSIS?

A. No, he did not.

[126] Calculated by dividing the sum of the forecast returns by the sum of the actual returns.

Q. WHY IS MR. GARRETT'S HAMADA CAPM NOT APPLICABLE FOR THIS PROCEEDING?

A. As discussed previously, the Company's requested equity ratio is consistent with the range of equity ratios in place within both my updated proxy group and Mr. Garrett's proxy group. Further, while Mr. Garrett claims that the Company "is much less risky relative to the proxy group due to the decreased amount of debt in its capital structure,"[127] as discussed previously, the Company's long-term issuer rating is equivalent to that of the proxy group, indicating a comparable level of risk relative to the proxy group. As a result, there is no need for Mr. Garrett to adjust the *Value Line* betas in his CAPM for any difference in financial risk.

B. <u>Adjustments to the Cost of Equity</u>

Q. DOES MR. GARRETT CONSIDER A BUSINESS RISK ADJUSTMENT IN HIS RECOMMENDED ROE FOR UGI GAS?

A. No, he does not. Mr. Garrett argues that "[b]ecause investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company."[128]

Q. DO YOU AGREE WITH MR. GARRETT'S OBSERVATIONS?

A. No, I do not. As discussed on pages 54 through 56 of my Direct Testimony, when determining an appropriate ROE, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies. To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa. UGI Gas's smaller size relative to the Utility Proxy Group companies indicates

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127 OCA St. 3, at p. 41.
128 OCA St. 3, at p. 15.

greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Q. DID MR. GARRETT ADDRESS THE ISSUE OF A SIZE PREMIUM IN HIS TESTIMONY?

A. Yes. Mr. Garrett lists several reasons for his decision to not include a size premium in his recommendation, including: (1) numerous studies show that "the performance of large-cap stocks was basically equal to that of small-cap stocks,"[129] and (2) that the "discovery of the size effect phenomenon likely caused its own demise."[130]

Q. IS MR. GARRETT'S REVIEW OF THE SIZE PREMIUM CORRECT?

A. No, it is not. First, Mr. Garrett notes that after 1983, U.S. small-cap stocks underperformed large-cap stocks.[131] The issue with Mr. Garrett's position is that the size premium measures the increased risk associated with a company's smaller size; Mr. Garrett is only focused on returns. As I discussed in my Direct Testimony, smaller companies face increased business risk as they are less equipped to cope with significant events that affect sales, revenues, and earnings, as the loss of a few larger customers will have a greater effect on a smaller company than a larger company.[132]

This is further evident when we consider that increasing capital costs (i.e., risk) for one set of securities will put downward pressure on those securities as investors transition to securities with lower risk. Under this premise, the underperformance is directly tied to the increase in risk. As such, Mr. Garrett's premise that smaller companies'

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129 OCA St. 3, at p. 44.
130 OCA St. 3, at p. 44.
131 OCA St. 3, at p. 43.
132 UGI Gas St. No. 8, at p. 54.

underperformance indicates a reduction of risk is in fact the opposite – underperformance indicates an increasing level of risk.

Q. MR. GARRETT POINTS TO A PASSAGE PUBLISHED IN 2015 BY IBBOTSON[133] THAT STATES THAT THE SIZE PREMIUM NO LONGER EXISTS. WHAT IS YOUR RESPONSE?

A. Despite their findings, Kroll (which now owns Ibbotson) continues to publish data on their findings on the presence of a size premium in the market and has provided additional measures of size and relative risk premiums. In addition to market capitalization, Kroll includes book common equity, market value of invested capital, five-year average net income, five-year average earnings before interest, taxes, depreciation and amortization, total assets, total sales, and total employees as valid measures of size from which relative size premiums are derived. If Kroll found that the size premium ceased to exist, it would not publish the size data it does.

Q. DO YOU AGREE WITH MR. GARRETT THAT THE SIZE EFFECT NO LONGER EXISTS?

A. No, I do not. While the historical returns of large companies may have outperformed small utilities over the last several years, risk is measured by volatility, not returns. A study by Clifford Ang detailed the returns and volatility of returns of companies by size, showing while larger companies out-performed smaller companies, smaller companies exhibited more risk.[134] Reviewing data from the same source as the Ang study, I replicated the study through February 2026. Table 6 presents the largest monthly gain and loss for each value-weighted decile for the period 1981 through February 2026. As shown in Table 6, small

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133 OCA St. 3, at p. 44.

134 Clifford S. Ang, "The Absence of a Size Effect Relevant to the cost of Equity", Business Valuation Review, Volume 37, No. 3, 2018.

capitalization stocks exhibit more volatility (i.e., risk) in their returns than larger capitalization stocks.

Table 6: Size and Volatility of Returns[135]

Decile:	1	2	3	4	5	6	7	8	9	10
Largest Gain:	29.4%	25.3%	21.1%	20.0%	19.8%	16.9%	17.1%	14.5%	14.1%	13.4%
Largest Loss:	-28.8%	-30.2%	-28.8%	-29.7%	-27.8%	-26.3%	-26.0%	-23.9%	-22.5%	-19.8%

Further, SBBI-2023 shows that the total return of large-cap stocks over the 1926-2022 period has a standard deviation of 19.8%, compared to 31.2% for small-cap stocks, echoing the findings of Table 6.[136] The higher level of risk indicates a higher level of required return.

Q. WHAT ARE MR. GARRETT'S CONCERNS WITH YOUR FLOTATION COST ADJUSTMENT?

A. Mr. Garrett states that flotation costs should not have an increasing impact on UGI Gas's return on equity because: (1) flotation costs are not actual "out-of-pocket" costs; (2) the market already accounts for flotation costs; and (3) the requested ROE is already too high and increasing it further would be inappropriate.[137]

Q. WHAT IS YOUR RESPONSE?

A. Flotation costs are reflected on the balance sheet under "paid in capital" and incurred over time. As a result, flotation costs remain part of a company's cost structure during the test year and beyond even if the costs were incurred prior to the test year.[138]

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135 Deciles in ascending order with one (1) representing the smallest stocks by market capitalization. Source: http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html#BookEquity.

136 SBBI-2023, at 137. Note: Utility companies are included in this data set.

137 OCA St. 3, at pp. 46-47.

138 UGI Gas St. No. 8, at pp. 62-63.

Mr. Garrett's observation that underwriter fees are not "out-of-pocket" expenses is a distinction without a meaningful difference.[139] Whether paid directly or indirectly through an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. Mr. Garrett points out that under federal law, the underwriters' compensation must be disclosed in the offering prospectus.[140] I agree. In fact, those prospectuses are the source of the issuance costs included in Schedule DWD-11 to my Direct Testimony. Because those costs were incurred, the net proceeds to the issuing company were less than the gross proceeds. Whether the issuer wrote a check or received the proceeds at a discount does not matter. What does matter is that issuance costs are a permanent reduction to common equity, and absent a recovery of those costs, the issuing company will not be able to earn its required return.

Furthermore, as discussed in my response to Mr. Breuning, denying recovery of issuance costs would penalize the investors that fund the utility operations.

C. Response to Mr. Garrett's Critiques of Company Testimony

Q. DOES MR. GARRETT HAVE ANY CRITIQUES OF YOUR ANALYSES PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes, he does. Mr. Garrett's critiques of my Direct Testimony are: (1) my use of overstated DCF growth rates; (2) my use of an MRP he deems unreasonable for not being in line with his MRP estimates; and (3) my inclusion of adjustments for Company-specific factors.

I have already addressed critique (3) previously and will not address it again here. I will discuss Mr. Garrett's remaining arguments here.

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139 OCA St. 3, at p. 46.
140 OCA St. 3, at p. 46.

Q. MR. GARRETT OPINES THAT GROWTH IN A DCF MODEL IS LIMITED BY THE LONG-TERM GROWTH IN GDP.[141] WHY IS LONG-TERM GROWTH IN GDP NOT AN UPPER LIMIT FOR TERMINAL GROWTH AS MR. GARRETT CONTENDS?

A. First, GDP is not a market measure – rather it is a measure of the value of the total output of goods and services, excluding inflation, in an economy. While I understand that EPS growth is also not a market measure, it is well established in the financial literature that projected growth in EPS is the superior measure of dividend growth in a DCF model.[142] Furthermore, GDP is simply the sum of all private industry and government output in the United States, and its growth rate is simply an average of the value of those industries. To illustrate, Schedule DWD-9R presents the compound annual growth rate of the industries that comprise GDP from 1947 to 2025. Of the 15 industries represented, seven industries (including utilities) grew faster than the overall GDP, and eight industries grew slower than the overall GDP.[143] Given that utilities have grown faster than the overall GDP over the 1947-2025 time period, I disagree with Mr. Garrett's suggestion that "it is reasonable to conclude that the long-term growth of a domestic firm cannot outpace the growth rate of the aggregate economy in which it operates (as measured by U.S. GDP in this case)"[144]

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141 OCA St. 3, at pp. 26-27.

142 *See*, for example, Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, Spring 1986; Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing, Spring 1999; Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

143 Source: Bureau of Economic Analysis.

144 OCA St. 3, at p. 27.

Q. DID YOU CONDUCT ANOTHER ANALYSIS THAT CALCULATES THE AMOUNT OF TIME IT WOULD TAKE AN INDUSTRY TO OVERTAKE THE ENTIRE ECONOMY?

A. Yes. I examined the value added by industry from 1947 to 2025 in Schedule DWD-9R and used the compound annual growth rates for the highest growth rate industry (i.e., Educational Services, Healthcare, and Social Assistance at 8.53% per year) to see when that industry would comprise the entire economy. In the year 2285, or 338 years from the 1947 starting point, the industry would comprise over 50% of GDP, and in the year 7964, or 6,017 years after the 1947 starting point, the industry would comprise 100% of GDP.[145] Not only have individual companies or industries consistently grown at rates beyond GDP growth, but they have done so without overtaking the entire economy. While Mr. Garrett's argument may be technically correct, it is unrealistic at best.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. Myron Gordon, the "father" of the standard regulatory version of the DCF model widely utilized throughout the United States in rate base/rate of return regulation, recognized the significance of analysts' forecasts of growth in EPS in a speech he gave in March 1990 before the Institute for Quantitative Research and Finance,[146] stating on page 12:

> We have seen that earnings and growth estimates by security analysts were found by Malkiel and Cragg to be superior to data obtained from financial statements for the explanation of variation in price among common

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[145] To put the amount of time that will take these two milestones to happen in perspective, approximately 300 years ago, in the year 1719, France and Spain were at war in New France (now Louisiana), and approximately 3,476 years ago, in the year 1457 BC, the first recorded battle in military history, the Battle of Megiddo, was waged between the Egyptians, led by Pharaoh Thutmose III against Kadesh, Canaanite, Mitanni, and Amurru forces. *See also* Zager and Evans, *In the Year 2525*, *on* 2525 (Exordium & Terminus) (RCA 1968).

[146] Myron J. Gordon, *The Pricing of Common Stock*, Presented before the Spring 1990 Seminar, March 27, 1990 of the Institute for Quantitative Research in Finance, Palm Beach, FL.

> stocks… estimates by security analysts available from sources such as IBES are far superior to the data available to Malkiel and Cragg.
>
> * * *
>
> Eq (7) is not as elegant as Eq (4), but it has a good deal more intuitive appeal. It says that investors buy earnings, but what they will pay for a dollar of earnings increases with the extent to which the earnings are reflected in the dividend or in appreciation through growth.

Professor Gordon recognized that the total return is largely affected by the terminal price, which is mostly affected by earnings (hence P/E multiples).

Studies performed by Cragg and Malkiel[147] demonstrate that analysts' forecasts are superior to historical growth rate extrapolations. While some question the accuracy of analysts' forecasts of EPS growth, the level of accuracy of those analysts' forecasts well after the fact does not really matter. What is important is that the forecasts reflect widely held expectations influencing investors at the time they make their pricing decisions, and hence, the market prices they pay.

In addition, Jeremy J. Siegel also supports the use of security analysts' EPS growth forecasts when he states:

> For the equity holder, the source of future cash flows is the earnings of firms.
>
> * * *
>
> Some people argue that shareholders most value stocks' cash dividends. But this is not necessarily true.
>
> * * *
>
> Since the price of a stock depends primarily on the present discounted value of all expected future dividends, it appears that dividend policy is crucial to determining the value of the stock. However, this is not generally true.
>
> * * *

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147 John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices (University of Chicago Press, 1982) Chapter 4.

> Since stock prices are the present value of future dividends, it would seem natural to assume that economic growth would be an important factor influencing future dividends and hence stock prices. However, this is not necessarily so. The determinants of stock prices are earnings and dividends on a *per-share* basis. Although economic growth may influence *aggregate* earnings and dividends favorably, economic growth does not necessarily increase the growth of per-share earnings of dividends. It is earnings per share (EPS) that is important to Wall Street because per-share data, not aggregate earnings or dividends, are the basis of investor returns. (italics in original)[148]

Q. WHAT IS YOUR CONCLUSION OF THE APPROPRIATE GROWTH RATE FOR USE IN THE DCF MODEL?

A. In view of the above, I recommend the Commission rely solely on projected EPS growth rates, as Mr. Breuning has proposed, when determining the indicated ROE for UGI Gas using the DCF model.

Q. MR. GARRETT STATES THAT YOUR MRP IS UNREASONABLE IN VIEW OF HIS MEASURES OF MRP AS PRESENTED IN HIS CAPM ANALYSIS.[149] PLEASE RESPOND.

A. Even though Mr. Garrett questions the reasonableness of my calculated market returns and MRPs, they are consistent with actual realized returns and MRPs, as shown on Table 7, below, and Schedule DWD-10R.

Table 7: Percentile Ranks of Calculated Market Returns and Risk Premiums[150]

	D'Ascendis Testimony	%	Percentile Rank
Average Market Return	Direct	13.16%	47th
Average Market Return	Rebuttal	13.46%	47th
Average Market Risk Premium	Direct	8.63%	49th
Average Market Risk Premium	Rebuttal	8.71%	49th

148 Jeremy J. Siegel, Stocks for the Long Run – The Definitive Guide to Financial Market Returns and Long-Term Investment Strategies, McGraw-Hill 2002, pp. 90-94.
149 OCA St. 3, at pp. 40-41.
150 Schedule DWD-10R.

Chart 2: Frequency Distribution of Observed Market Returns, 1926 - 2025[151]

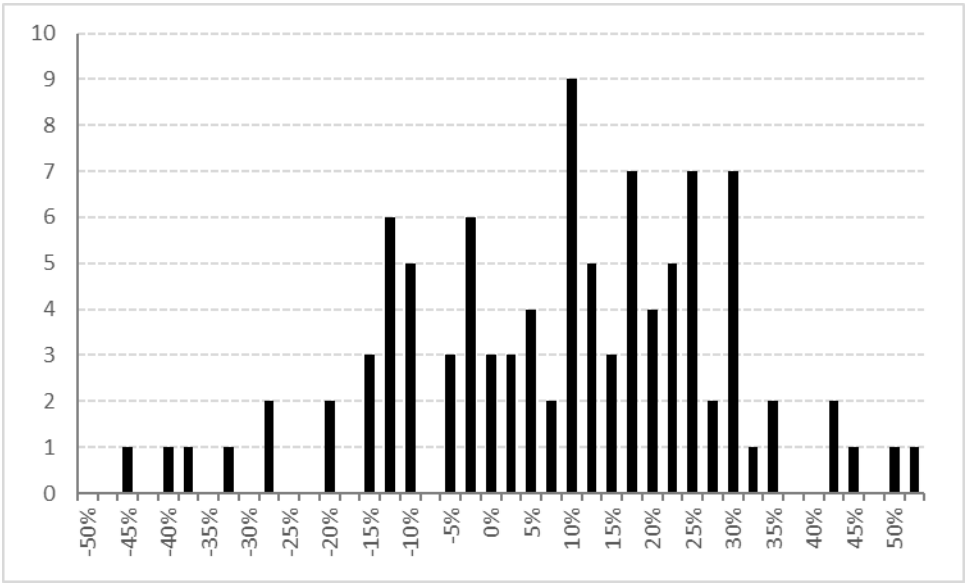
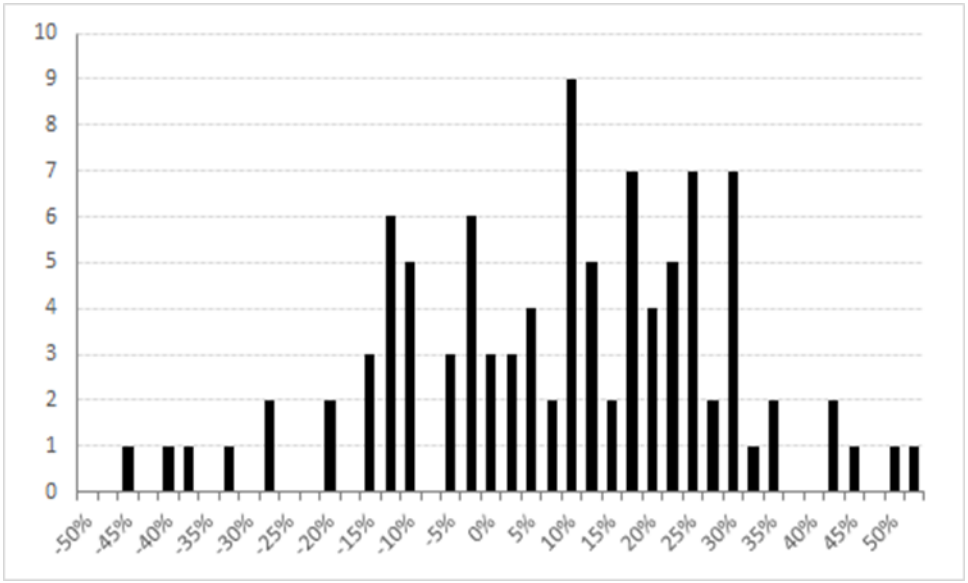


Chart 3: Frequency Distribution of Observed Market Risk Premiums, 1926 - 2025[152]



Given all of the above, the market returns and ERPs I use in my analyses are consistent with observed values. Thus, Mr. Garrett's concerns should be dismissed.

151 Schedule DWD-10R.
152 Schedule DWD-10R.

VI. RESPONSE TO OSBA WITNESS EWEN

Q. PLEASE PROVIDE A SUMMARY OF MR. EWEN'S TESTIMONY REGARDING UGI GAS'S OVERALL COST OF CAPITAL.

A. Mr. Ewen alleges that my recommended ROE ignores a key provision of the *Hope* and *Bluefield* Supreme Court decisions; specifically, that rates should balance the interests of the utility and the various stakeholders.[153] Mr. Ewen also contends that UGI Gas's proposed extension of its current WNA pilot program "reduces utility risk and therefore should reduce the utility cost of capital."[154]

Q. DO YOU AGREE WITH MR. EWEN THAT YOU IGNORED KEY COMPONENTS OF THE *HOPE* AND *BLUEFIELD* SUPREME COURT DECISIONS?

A. No, I do not. My Direct Testimony and recommendation in this proceeding balances the interests of all stakeholders – the customers receive safe and reliable service, and the Company is able to recover its costs plus a fair rate of return on its investment, which is based on current and expected market data applied to comparable risk companies. Since Mr. Ewen does not provide an independent, market-based ROE analysis, his contention that my recommended return does not balance the interests of the various stakeholders in this proceeding is unfounded.

Q. DO YOU AGREE WITH MR. EWEN THAT A WNA MECHANISM REDUCES THE COMPANY'S RELATIVE RISK?

A. No, I do not. As discussed previously, it is important to keep in mind that risk, as it relates to investor required returns, is comparative. Because returns are based on the economic

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153 OSBA St. No. 1, at p. 4.
154 OSBA St. No. 1, at p. 5.

principle of opportunity costs, risk and return should be viewed in the context of alternative investments. That economic principle is consistent with the *Hope* and *Bluefield* "comparable risk" standard, under which the authorized return should be comparable to those available to firms of similar risk.

Consistent with those economic and regulatory principles, risk and return should not be viewed in isolation. Rather, the analytical issue is whether the mechanisms in place would reduce a utility's risk relative to its peers such that investors would specifically and measurably reduce their required return for that utility.

Exhibit DWD-11R provides a summary of WNAs and other alternative ratemaking mechanisms ("ARM") in effect at each utility subsidiary of my Utility Proxy Group. As Exhibit DWD-11R demonstrates, WNAs and other ARMs are present in every proxy company, and any risk reduction due to those mechanisms would be reflected in their market data. As such, the presence of the Company's ARMs are not unique compared to the Utility Proxy Group and, therefore, does not indicate a lower level of relative risk.

Q. ARE THERE STUDIES ADDRESSING THE RELATIONSHIP BETWEEN DECOUPLING MECHANISMS, GENERALLY, AND ROES?

A. Yes. In March 2014, The Brattle Group ("Brattle") published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities.[155] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenues, net income can still vary. Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between decoupling and ROE should be

[155] The Brattle Group, The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation, Prepared for the Energy Foundation, March 20, 2014.

examined in that context. Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would warrant a reduction to the ROE. In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.[156]

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax Weighted Average Cost of Capital for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the cost of capital and revenue decoupling structures.[157] Given all of the above, it is evident that WNA or similar decoupling mechanism do not reduce relative utility risk and should have no impact on the Company's cost of capital. In light of all the above, Mr. Ewen's concerns should be dismissed.

VII. RESPONSE TO CAUSE-PA WITNESS CICERO

Q. PLEASE PROVIDE A SUMMARY OF MR. CICERO'S TESTIMONY REGARDING UGI GAS'S OVERALL COST OF CAPITAL.

A. Mr. Cicero recommends no rate increase, implying an ROE of 7.70%, which is the Company's expected ROE at present rates.[158] He claims that the Company's current rates allow them to provide safe and reliable service, recover reasonably and prudently incurred expenses, and provides the opportunity to earn a fair return on the Company's

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156 Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation, November 2016.

157 Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation, November 2016.

158 CAUSE-PA St. No. 1, at p. 40.

investment.[159] Mr. Cicero also believes that the Company's WNA, fully projected future test year, and Distribution System Improvement Charge ("DSIC") reduces its risk and that risk reduction should be reflected in the ROE.[160] Finally, Mr. Cicero recommends an imputed capital structure containing 50.00% long-term debt and 50.00% common equity.[161]

Q. DO YOU HAVE ANY CONCERNS WITH MR. CICERO'S DIRECT TESTIMONY?

A. Yes, I do. While Mr. Cicero claims that a 7.70% ROE is a fair rate of return for UGI Gas, he does not provide any independent, market-based analysis that shows that a 7.70% ROE would be commensurate with returns for firms with comparable risk. I also disagree with Mr. Cicero's claim that the Company's ARMs lower its risk compared to the members of the Utility Proxy Group as discussed above while addressing Mr. Ewen's testimony and his recommended hypothetical capital structure, which was addressed in Section III, above.

Q. DOES MR. CICERO CONDUCT AN INDEPENDENT, MARKET-BASED ANALYSIS OF THE INVESTOR REQUIRED ROE FOR FIRMS THAT HAVE COMPARABLE RISK AS THE COMPANY?

A. No, he does not. As discussed in my Direct Testimony,[162] a fair return should be commensurate with returns on investments in other enterprises having corresponding risks and needs to be sufficient to assure confidence in the utility's financial integrity, allowing it to attract capital at reasonable costs and terms. Mr. Cicero's lack of analysis of market data or data from comparable risk companies leaves his recommendations regarding the

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159 CAUSE-PA St. No. 1, at pp. 5, 34.
160 CAUSE-PA St. No. 1, at pp. 13-14.
161 CAUSE-PA St. No. 1, at p. 46.
162 UGI Gas St. No. 8, at pp. 5-6.

Company's appropriate capital structure and corresponding cost rates unsupported. As such, I recommend that the Commission dismiss them.

Q. MR. CICERO COMPARES YOUR RECOMMENDED ROE WITH 50- AND 100-YEAR RETURNS FOR THE DOW JONES INDUSTRIAL AVERAGE AND S&P 500, CLAIMING THAT YOUR RECOMMENDED ROE IS SIGNIFICANTLY HIGHER.[163] IS THAT COMPARISON APT?

A. No, it is not. The historical returns Mr. Cicero uses for his comparison are inflation-adjusted (i.e., real) and calculated using geometric returns whereas my recommended ROE includes inflation (i.e., nominal) and uses arithmetic returns. These returns are not comparable returns and need to be properly converted to compare them. As shown on Schedule DWD-12R, converting the real, geometric historical returns to nominal, arithmetic historical returns result in market returns ranging from 11.96% to 12.92%, which is higher than my recommended ROE and consistent with similar data from Kroll as noted above.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY

A. Given the discussion above and my updated analysis, I continue to believe that my recommended ROE of 10.75% is reasonable for the Company at this time.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.75% FAIR AND REASONABLE FOR UGI GAS AND ITS CUSTOMERS?

A. Yes, it is.

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[163] CAUSE-PA St. No. 1, at p. 44.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

UGI Gas Rebuttal Exhibit B

UGI Utilities, Inc.
Table of Contents
UGI Gas Rebuttal Exhibit B - Schedules to the Rebuttal Testimony of Dylan W. D'Ascendis

	Rebuttal Schedule
Updated Cost of Capital Results	DWD-1R
Comparable Earnings: New Life for an Old Precept	DWD-2R
Jack C. Francis' Investments: Analysis and Management	DWD-3R
Correction of Mr. Breuning's CAPM	DWD-4R
Comparison of Market Return Measures	DWD-5R
Prediction of Equity Risk Premiums Relative to Moody's A2 Rated Utility Bond Yields	DWD-6R
Standard Deviation of DCF Results for Mr. Breuning's Natural Gas Proxy Group	DWD-7R
Mr. Garrett's Corrected Implied ERP Calculation	DWD-8R
Gross Domestic Product by Industry	DWD-9R
Frequency Distribution of Market Returns and Market Risk Premiums	DWD-10R
Summary of Decoupling and Capital Investment Rate Mechanisms for the Utility Proxy Group	DWD-11R
Mr. Cicero Corrected Market Returns	DWD-12R

UGI Utilities, Inc.
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	45.75%	5.22%	(1)	2.39%
Common Equity	54.25%	10.75%	(2)	5.83%
Total	100.00%			8.22%

Notes:
(1) Company-provided
(2) From page 2 of this Schedule.

UGI Utilities, Inc.
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.40%
2.	Risk Premium Model (RPM) (2)	10.68% - 11.13%
3.	Capital Asset Pricing Model (CAPM) (3)	10.60% - 11.90%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	10.80% - 11.67%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.40% - 11.90%
6.	Business Risk Adjustment (5)	0.05%
7.	Flotation Cost Adjustment (6)	0.12%
8.	Indicated Common Equity Cost Rate after Adjustment	10.57% - 12.07%
9.	Recommended Common Equity Cost Rate	10.75%

Notes:
(1) From page 6 of this Schedule.
(2) From page 13 of this Schedule.
(3) From page 23 and 24 of this Schedule.
(4) From page 29 of this Schedule.
(5) Business risk adjustment to reflect UGI Utilities, Inc.'s unique risk compared to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.
(6) From page 38 of this Schedule.

Proxy Group of Six Natural Gas Companies
Capitalization and Financial Statistics (1)
2021 - 2025, Inclusive

	2025	2024	2023	2022	2021	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$11,734.255	$10,577.686	$9,569.315	$8,895.070	$7,740.838	
Short-Term Debt	$306.832	$443.518	$724.902	$787.304	$621.633	
Total Capital Employed	$12,041.087	$11,021.204	$10,294.217	$9,682.374	$8,362.471	
Indicated Average Capital Cost Rates (2)						
Total Debt	4.14 %	4.35 %	4.09 %	3.15 %	2.86 %	
Preferred Stock	- %	3.37 %	4.31 %	3.56 %	4.54 %	
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	51.78 %	51.56 %	51.94 %	52.43 %	51.34 %	51.81 %
Preferred Stock	-	-	0.42	1.51	1.59	0.70
Common Equity	48.22	48.44	47.64	46.06	47.07	47.49
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	53.56 %	54.55 %	54.29 %	56.78 %	55.96 %	55.03 %
Preferred Stock	-	-	0.36	1.37	1.54	0.65
Common Equity	46.44	45.45	45.35	41.85	42.50	44.32
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	6.15 %	5.27 %	5.34 %	3.95 %	4.91 %	5.12 %
Market / Average Book Ratio	170.10	159.78	162.91	187.60	173.93	170.86
Dividend Yield	3.45	3.66	3.66	3.21	3.41	3.48
Dividend Payout Ratio	55.00	69.88	69.62	33.52	62.73	58.15
Rate of Return on Average Book Common Equity	10.31 %	8.56 %	8.89 %	8.10 %	9.26 %	9.02 %
Total Debt / EBITDA (3)	4.49 x	4.88 x	4.83 x	5.37 x	5.60 x	5.03 x
Funds from Operations / Total Debt (4)	14.50 %	15.55 %	30.30 %	14.66 %	8.75 %	16.75 %
Total Debt / Total Capital	53.56 %	54.55 %	54.29 %	56.78 %	55.96 %	55.03 %

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.

(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).

(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K.

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Six Natural Gas Companies
2021 - 2025, Inclusive

	2025	2024	2023	2022	2021	5 YEAR AVERAGE
Atmos Energy Corporation						
Long-Term Debt	39.68 %	39.04 %	37.62 %	45.81 %	39.35 %	40.30 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	60.32	60.96	62.38	54.19	60.65	59.70
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources Corporation						
Long-Term Debt	58.77 %	58.24 %	59.16 %	58.49 %	57.81 %	58.49 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	41.23	41.76	40.84	41.51	42.19	41.51
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NiSource Inc.						
Long-Term Debt	62.09 %	60.60 %	57.26 %	55.77 %	57.09 %	58.56 %
Preferred Stock	0.00	0.00	2.51	9.03	9.55	4.22
Common Equity	37.91	39.40	40.23	35.20	33.36	37.22
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Holding Company						
Long-Term Debt	62.25 %	55.25 %	55.11 %	53.21 %	52.12 %	55.59 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	37.75	44.75	44.89	46.79	47.88	44.41
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt	40.92 %	40.71 %	44.05 %	42.10 %	41.74 %	41.90 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	59.08	59.29	55.95	57.90	58.26	58.10
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Southwest Gas Holdings, Inc.						
Long-Term Debt	46.97 %	55.54 %	58.43 %	59.25 %	59.90 %	56.02 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	53.03	44.46	41.57	40.75	40.10	43.98
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Six Natural Gas Companies						
Long-Term Debt	51.78 %	51.56 %	51.94 %	52.43 %	51.34 %	51.81 %
Preferred Stock	0.00	0.00	0.42	1.51	1.59	0.70
Common Equity	48.22	48.44	47.64	46.06	47.07	47.49
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

UGI Utilities, Inc.
Operating Subsidiary Company Capital Structures of the
Proxy Group of Six Natural Gas Companies

Company Name	Parent Company Ticker	2025 Common Equity	2025 Long-Term Debt	2025 Total Capital
Atmos Energy Corporation	ATO	59.31%	40.69%	100.00%
New Jersey Natural Gas Company	NJR	54.63%	45.37%	100.00%
Northern Indiana Public Service Company	NI	58.48%	41.52%	100.00%
Northwest Natural Gas Company	NWN	48.36%	51.64%	100.00%
ONE Gas, Inc.	OGS	56.50%	43.50%	100.00%
Southwest Gas Corporation	SWX	50.12%	49.88%	100.00%
	Average	54.57%	45.43%	
	Maximum	59.31%	51.64%	
	Minimum	48.36%	40.69%	

Source: S&P Global Market Intelligence.
Company Financial Statements.
Data for Northern Indiana Public Service Company is from FERC financial Report Form Form No. 1 at PDF 30.

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Companies

Proxy Group of Six Natural Gas Companies	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth in EPS (3)	[6] Adjusted Dividend Yield (4)	[7] Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.26 %	8.00 %	7.00 %	8.21 %	7.74 %	2.35 %	10.09 %
New Jersey Resources Corporation	3.67	5.00	NA	8.55	6.78	3.79	10.57
NiSource Inc.	2.66	7.50	6.00	8.64	7.38	2.76	10.14
Northwest Natural Holding Company	3.97	6.00	NA	7.50	6.75	4.10	10.85
ONE Gas, Inc.	3.28	6.00	8.10	6.90	7.00	3.39	10.39
Southwest Gas Holdings, Inc.	2.91	NA	9.20	12.01	10.61	3.06	13.67 (6)
						Average	10.41 %
						Median	10.39 %
						Average of Mean and Median	10.40 %

NA= Not Available

Notes:

(1) Indicated dividend at 3/31/2026 divided by the average closing price of the last 60 trading days ending 3/31/2026 for each company.
(2) From pages 7 through 12 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.26% x (1+(1/2 x 7.74%)) = 2.35%.
(5) Column 5 + Column 6.
(6) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 3/31/2026
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 171.46 | P/E RATIO 21.0 (Trailing: 22.3 Median: 21.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 2/20/26
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Raised 2/20/26
BETA .80 (1.00 = Market)

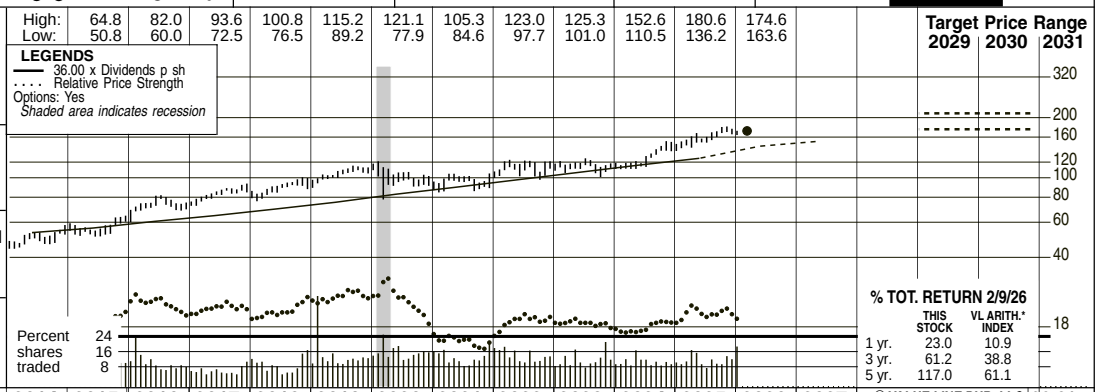
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$152-$238 $195 (15%)

2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	210	(+20%)	*8%*
Low	175	(Nil)	*3%*

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	458	462	466
to Sell	320	335	324
Hld's(000)	157845	161659	160024



% TOT. RETURN 2/9/26

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.0	10.9
3 yr.	61.2	38.8
5 yr.	117.0	61.1

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	26.83	29.11	*29.15*	*28.45*	Revenues per sh [A]	*32.50*
4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	11.03	11.97	*12.80*	*13.45*	"Cash Flow" per sh	*15.80*
2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.83	7.46	*8.15*	*8.75*	Earnings per sh [AB]	*10.70*
1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	3.48	*4.00*	*4.24*	Div'ds Decl'd per sh [C]■	*5.05*
6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	18.92	22.04	*24.55*	*23.75*	Cap'l Spending per sh	*20.10*
24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	78.31	83.92	*87.70*	*94.35*	Book Value per sh	*111.00*
90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.26	161.57	*171.00*	*180.00*	Common Shs Outst'g [D]	*200.00*
13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	17.3	20.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.04	.90	1.05			Relative P/E Ratio	*1.00*
4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	2.7%	2.3%			Avg Ann'l Div'd Yield	*2.6%*
						3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4165.2	4702.8	*4985*	*5125*	Revenues ($mill) [A]	*6500*
						350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1042.9	1198.8	*1395*	*1575*	Net Profit ($mill)	*2140*
						36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.6%	18.9%	*20.0%*	*21.0%*	Income Tax Rate	*25.0%*
						10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	25.0%	25.5%	*28.0%*	*30.7%*	Net Profit Margin	*32.9%*
						38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	39.3%	39.8%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
						61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	60.7%	60.2%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
						5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	20018	22534	*25000*	*28300*	Total Capital ($mill)	*37000*
						8280.5	9259.2	10371	11788	13355	15064	17240	19607	22204	25293	*28000*	*31000*	Net Plant ($mill)	*40000*
						7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	5.7%	5.7%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
						10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	8.8%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
						10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.6%	8.8%	*9.5%*	*9.5%*	Return on Com Equity	*9.5%*
						5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	4.8%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
						50%	50%	48%	48%	49%	49%	49%	49%	47%	46%	*49%*	*49%*	All Div'ds to Net Prof	*47%*

CAPITAL STRUCTURE as of 12/31/25
Total Debt $9632.8 mill. **Due in 5 Yrs** $1170.0 mill.
LT Debt $9621.8 mill. **LT Interest** $172.0 mill.
(LT interest earned: 9.6x; total interest coverage: 9.6x)
Leases, Uncapitalized Annual rentals $56.5 mill.

Pfd Stock None

Pension Assets-9/25 $624.5 mill.
Oblig. $450.4 mill.
Common Stock 165,438,946 shs.
as of 1/30/26

MARKET CAP: $28.5 billion (Large Cap)

CURRENT POSITION ($MILL.)	2024	2025	12/31/25
Cash Assets	307.3	202.7	367.0
Other	825.0	850.0	1268.8
Current Assets	1132.3	1052.7	1635.8
Accts Payable	445.4	506.5	616.9
Debt Due	9.9	20.5	11.0
Other	750.6	835.6	819.1
Current Liab.	1205.9	1362.6	1447.0
Fix. Chg. Cov.	914%	1164%	1030%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '23-'25 to '29-'31
Revenues	-4.5%	2.5%	*2.5%*
"Cash Flow"	7.5%	7.5%	*6.5%*
Earnings	9.0%	9.5%	*8.0%*
Dividends	8.0%	9.0%	*8.0%*
Book Value	10.0%	10.0%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	701.5	658.0	4165.2
2025	1176.0	1950.5	838.8	737.5	4702.8
2026	1342.6	*2030*	*825*	*787.4*	*4985*
2027	*1336*	*2075*	*878*	*836*	*5125*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.08	.86	6.83
2025	2.23	3.03	1.16	1.07	7.46
2026	2.44	*3.26*	*1.28*	*1.17*	*8.15*
2027	*2.60*	*3.41*	*1.43*	*1.31*	*8.75*

Calendar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805	.805	.87	3.29
2025	.87	.87	.87	1.00	3.61
2026	1.00				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to about 3.4 million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2025: residential, 68.7%; commercial, 27.2%; industrial, 2.9%; and other, 1.2%. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .4% of common stock (12/25 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

It's been business as usual at Atmos Energy. Fiscal 2026 (ends September 30th) started on a high note, with first-quarter earnings per share climbing 9.4%, to $2.44, relative to the prior-year tally of $2.23. One contributor was the distribution division, supported partly by rate adjustments (primarily in the Mid-Tex Division) and higher consumption. Also, results of the pipeline & storage unit benefited, among other things, from the Gas Reliability Infrastructure Program filing approved in June 2025 and the System Safety and Integrity Rider filing approved in November 2024. So, full-year profits stand to grow near 10%, to $8.15 a share, versus fiscal 2025's $7.46 figure. Regarding fiscal 2027, the bottom line may advance another 7%, to $8.75 a share, as operating margins expand further.

Finances are solid. When the December interim ended, cash on hand was $367.0 million. Furthermore, long-term debt looked reasonable (40% of total capital) and short-term borrowings were minimal. Also, $5.2 billion in common stock and/or debt securities remained available for issuance (out of $8.0 billion) under a shelf registration statement expiring in December, 2027. Finally, Atmos had undrawn credit facilities totaling $3.1 billion plus a $1.5 billion commercial paper program.

The capital spending budget for fiscal 2026 is expected to be roughly $4.2 billion. That's some 18% above the prior-year level of around $3.6 billion. Similar to fiscal 2025, a major portion of the resources are being utilized to enhance the safety and reliability of the company's natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2026 through fiscal 2030 to lie in the vicinity of $26 billion. A large amount of the investments will continue to be deployed to where they are presently. If the balance sheet remains sound, Atmos ought to be able to achieve those goals.

These untimely shares hold unspectacular long-term total return potential. Capital gains possibilities out to 2029-2031 are moderate at the recent quotation. Also, the dividend yield is not exciting compared to *Value Line's* Natural Gas Utility Industry average.

Frederick L. Harris, III February 20, 2026

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early May. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE 51.76 | P/E RATIO 15.2 (Trailing: 16.0 Median: 17.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 2/20/26
SAFETY 2 Lowered 4/17/20
TECHNICAL 4 Lowered 2/20/26
BETA .75 (1.00 = Market)

18-Month Target Price Range

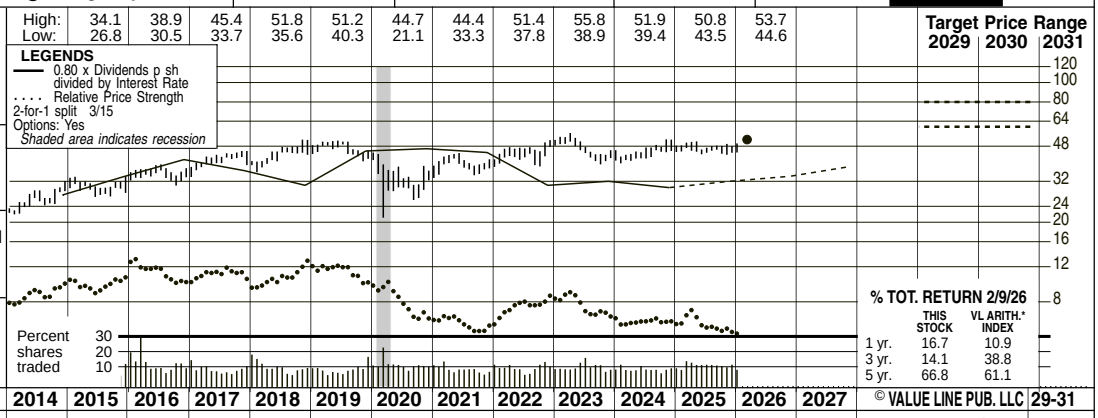
Low-High	Midpoint (% to Mid)
$44-$65	$55 (5%)

2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+55%)	*14%*
Low	60	(+15%)	*7%*

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	218	216	206
to Sell	165	168	175
Hld's(000)	74916	77155	76532



2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.19	20.12	18.06	20.27	*21.55*	*21.65*	Revenues per sh [A]	*23.80*
1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.84	4.28	4.59	5.22	*5.30*	*5.50*	"Cash Flow" per sh	*6.40*
1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.71	2.92	3.33	*3.40*	*3.60*	Earnings per sh [B]	*4.00*
.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.71	1.80	*1.90*	*2.10*	Div'ds Decl'd per sh [C] ■	*2.40*
1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.81	5.13	5.26	7.00	*7.35*	*7.40*	Cap'l Spending per sh	*7.60*
8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.88	20.40	22.12	23.80	*25.15*	*26.20*	Book Value per sh [D]	*31.60*
82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	96.25	97.58	99.46	100.48	*102.00*	*105.00*	Common Shs Outst'g [E]	*105.00*
15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.6	14.9	14.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.95	.98	.98	.78	.74			Relative P/E Ratio	*.95*
3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	3.9%	3.8%			Avg Ann'l Div'd Yield	*3.4%*
1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	1796.5	2036.4	*2200*	*2275*	Revenues ($mill) [A]	*2500*
138.1	149.4	240.5	175.0	196.2	207.7	240.3	264.7	289.8	335.6	*345*	*380*	Net Profit ($mill)	*420*
15.5%	17.2%	--	--	--	10.3%	22.0%	15.9%	23.0%	22.7%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.5%	16.1%	16.5%	*15.7%*	*16.7%*	Net Profit Margin	*16.8%*
47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	56.7%	57.5%	*56.5%*	*55.5%*	Long-Term Debt Ratio	*53.5%*
52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	43.3%	42.5%	*43.5%*	*44.5%*	Common Equity Ratio	*46.5%*
2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5079.9	5650.0	*5925*	*6200*	Total Capital ($mill)	*7100*
2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5403.2	5925.0	*6475*	*7100*	Net Plant ($mill)	*8700*
6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.8%	6.9%	7.0%	7.1%	*7.0%*	*7.5%*	Return on Total Cap'l	*7.0%*
11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	14.0%	*13.5%*	*13.5%*	Return on Shr. Equity	*12.5%*
11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.3%	13.2%	14.0%	*13.5%*	*13.5%*	Return on Com Equity	*12.5%*
4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.7%	5.7%	6.5%	*6.0%*	*6.0%*	Retained to Com Eq	*5.0%*
60%	59%	40%	59%	60%	56%	53%	57%	57%	54%	*56%*	*57%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/25
Total Debt $3804.7 mill. **Due in 5 Yrs** $668 mill.
LT Debt $3274.1 mill. **LT Interest** $125 mill.
Incl. $9.0 mill. capitalized leases.

Pension Assets-9/25 $355 mill.
Oblig. $325 mill.

Pfd Stock None

Common Stock 100,845,185 shs.
as of 2/2/26

MARKET CAP: $5.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2024	2025	12/31/25
Cash Assets	1.0	.6	2.4
Other	553.6	569.3	778.9
Current Assets	554.6	569.9	781.3
Accts Payable	169.2	222.6	136.5
Debt Due	480.8	353.8	530.6
Other	237.8	237.8	270.8
Current Liab.	887.8	780.9	937.9
Fix. Chg. Cov.	418%	365%	502%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '23-'25 to '29-'31
Revenues	-4.5%	-5.0%	*3.5%*
"Cash Flow"	7.0%	6.5%	*5.5%*
Earnings	5.5%	5.0%	*5.0%*
Dividends	7.0%	7.0%	*6.0%*
Book Value	7.0%	5.0%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	275.6	395.8	1796.5
2025	488.4	913.0	298.9	336.1	2036.4
2026	604.9	*850*	*340*	*405.1*	*2200*
2027	*625*	*875*	*350*	*425*	*2275*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2023	1.14	1.16	.10	.30	2.71
2024	.91	1.22	d.12	.92	2.92
2025	1.31	2.02	d.15	.15	3.33
2026	1.21	*1.85*	*.10*	*.24*	*3.40*
2027	*1.25*	*1.90*	*.15*	*.35*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42	.42	.45	1.71
2025	.45	.45	.45	.475	1.83
2026	.475				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 589,000 cust. at 9/30/25. Fiscal 2025 revenue breakdown: (Residential, 43%, Commercial, 18%, Firm Transportation, 5%, Out of Scope, 34%). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2025 dep. rate: 3.2%. Has 1,376 empls. Off./dir. own less than 1% of common; BlackRock, 15.2%; Vanguard, 11.0% (12/25 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Internet: www.njresources.com.

New Jersey Resources' outlook for fiscal 2026 has improved. (Year ends September 30th.) The fiscal year got off to a good start as December-quarter results were solid. The company reported revenues of $604.9 million, which was a strong increase year over year. Most of its operating segments showed nice improvement, especially the New Jersey Natural Gas arm. The Energy Services unit also delivered some nice gains. Meanwhile, earnings of $1.21 per share were better than our estimate by over a dime. Some recent events will likely boost the remainder of the year as well. The Energy Services segment benefited from natural gas price volatility and the recent weather conditions. The company was able to deliver uninterrupted service during the winter storm in January. With that in mind, we have raised our full-year fiscal 2026 top- and bottom-line estimates by $200 million and $0.25 per share, to $2.2 billion and $3.40.

The company is well positioned for the long haul. The New Jersey Natural Gas unit is expected to continue to increase its customer base, especially in Monmouth, Ocean, and Morris counties. Too, heavy capital investments in the division are likely to reap rewards down the road. The expansion of the Leaf River Energy Center ought to give a nice boost to the Storage and Transportation business. A recent FERC filing could open the door for a 70% increase in working gas capacity. Also, both Leaf River and the Adelphia Gateway recently received a favorable recontracting. There is also some positive news for the Clean Energy Ventures segment, thanks to increased solar projects. The end result should be decent cash generation out to late decade.

New Jersey Resources' shares have risen one notch in our Timeliness Ranking System to 3 (Average). The stock has had a strong showing of late, rising over 10% in value since our last full-page review in November. Despite the middling near-term outlook, total return potential out to 2029-2031 is worthwhile. This issue's most attractive feature remains the above-average yield. Too, those accounts looking to avoid risk may have interest here.

Kevin P. O'Sullivan *February 20, 2026*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2025: $721.4 million, $7.18/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	70

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NISOURCE INC. NYSE-NI

RECENT PRICE 44.45 | P/E RATIO 21.9 (Trailing: 22.8 Median: 20.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 4 Lowered 5/2/25
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Lowered 8/1/25
BETA .85 (1.00 = Market)

18-Month Target Price Range

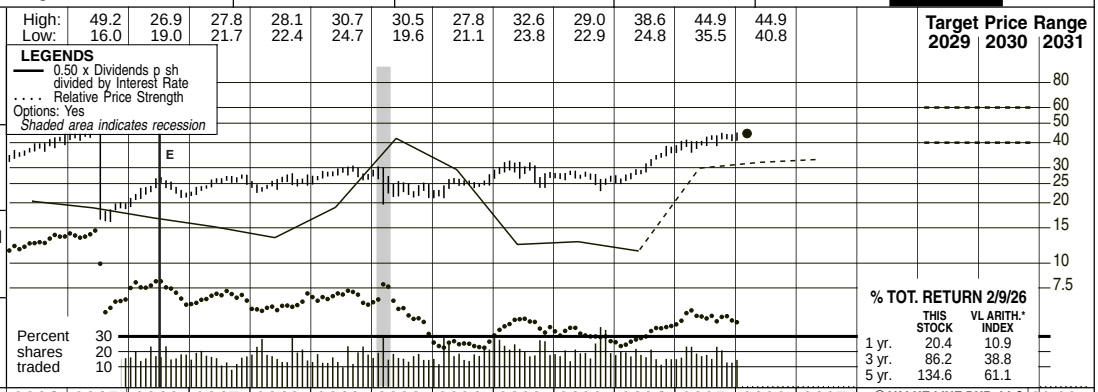
Low-High	Midpoint (% to Mid)
$38-$58	$48 (10%)

2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+35%)	10%
Low	40	(-10%)	1%

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	429	394	368
to Sell	296	333	339
Hld's(000)	437986	472780	449703



Target Price Range 2029 2030 2031
80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 2/9/26

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.4	10.9
3 yr.	86.2	38.8
5 yr.	134.6	61.1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
High:	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	38.6	44.9	44.9								
Low:	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8	35.5	40.8								
	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.20	12.31	11.61	13.88	*12.60*	*13.45*	Revenues per sh	*14.75*
	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.56	3.63	3.92	4.38	*4.20*	*4.90*	"Cash Flow" per sh	*5.75*
	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	1.75	1.95	*2.05*	*2.20*	Earnings per sh [A]	*2.65*
	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	1.06	1.12	*1.20*	*1.28*	Div'd Decl'd per sh [B] ■	*1.52*
	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	5.35	5.91	5.92	5.82	*6.00*	*6.00*	Cap'l Spending per sh	*6.25*
	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	14.63	17.40	18.48	25.79	*25.75*	*26.00*	Book Value per sh [C]	*31.60*
	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	405.30	412.14	447.38	469.82	478.40	*500.00*	*510.00*	Common Shs Outst'g [D]	*525.00*
	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	19.6	16.8	17.5	20.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.97	1.13	.93	.91	1.09			Relative P/E Ratio	*1.05*
	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	3.5%	2.8%			Avg Ann'l Div'd Yield	*3.0%*
	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	5455.1	6642	*6400*	*6850*	Revenues ($mill)	*7750*
	328.1	128.6	478.3	549.8	562.6	626.3	703.3	759.1	805.3	929.5	*1000*	*1125*	Net Profit ($mill)	*1650*
	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	16.5%	17.8%	16.3%	16.8%	*19.0%*	*19.0%*	Income Tax Rate	*18.0%*
	--	--	--	--	--	--	--	--	3.0%	3.0%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	57.2%	58.2%	*56.0%*	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	35.3%	40.3%	41.8%	46.0%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
	10129	11832	12856	13843	14972	16131	17099	19325	20759	27118	*28600*	*28750*	Total Capital ($mill)	*32400*
	13068	14360	15543	16912	16620	17882	19843	22275	25454	28688	*32000*	*32540*	Net Plant ($mill)	*36800*
	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	5.1%	5.0%	5.1%	4.6%	*3.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	9.2%	9.3%	8.0%	*8.0%*	*8.5%*	Return on Shr. Equity	*8.0%*
	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	10.8%	9.2%	9.2%	8.0%	*8.0%*	*8.5%*	Return on Com Equity	*8.5%*
	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.4%	3.9%	3.6%	3.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	63%	NMF	60%	64%	67%	64%	62%	60%	61%	57%	*59%*	*58%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 12/31/25
Total Debt $16303 mill. **Due in 5 Yrs** $6153 mill.
LT Debt $15547 mill. **LT Interest** $610 mill. (57% of Cap'l)

Leases, Uncapitalized Annual rentals $10.0 mill.
Pension Assets-12/25 $1.3 bill. **Oblig.** $1.3 bill.

Common Stock 478,533,171 shs. as of 2/4/26

MARKET CAP: $21.3 billion (Large Cap)

CURRENT POSITION ($MILL.)	2023	2024	12/31/25
Cash Assets	2245.4	156.6	110.1
Other	2254.0	1923.6	2267.1
Current Assets	4499.4	2080.2	2377.2
Accts Payable	749.4	863.1	1124.5
Debt Due	3072.4	1885.8	755.7
Other	1443.3	1364.5	1577.2
Current Liab.	5265.1	4113.4	3457.4
Fix. Chg. Cov.	225%	280%	290%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '29-'31
Revenues	-3.5%	-2.0%	*2.0%*
"Cash Flow"	1.0%	6.5%	*6.5%*
Earnings	0.5%	10.0%	*7.5%*
Dividends	--	5.5%	*6.0%*
Book Value	-1.0%	5.0%	*9.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	1966	1090	1027	1422	5505.4
2024	1706	1085	1076	1588	5455.1
2025	2183	1283	1273	1903	6642.2
2026	*2300*	*1350*	*1275*	*1475*	*6400*
2027	*2450*	*1450*	*1350*	*1600*	*6850*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	.77	.11	.19	.53	1.60
2024	.85	.21	.20	.49	1.75
2025	.98	.22	.19	.53	1.95
2026	*1.00*	*.30*	*.20*	*.55*	*2.05*
2027	*1.05*	*.35*	*.20*	*.60*	*2.20*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265	.265	.265	1.06
2025	.28	.28	.28	.28	1.12
2026	.30				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 492,690 electric in Indiana, 3.3 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 34%; gas, 63%; other, 3%. Generating capacity, fossil feuls 56%; renewables, 44%. 2024 reported depreciation rates: 3.0% electric, 2.6% gas. Had 7,746 employees as of 12/31/2024. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource, Inc. posted strong results in 2025. The company reported full-year numbers just as we were going to press. Full-year revenues and earnings improved nicely year over year. Healthy increases in gas distribution from both the Columbia and NIPSCO operating units was impressive. The electric generation and power delivery side also picked up. Meanwhile, earnings of $1.95 per share topped our target by a nickel and rose 11% over 2024.

The company is well-positioned for the near term. NiSource has been seeing healthy trends in most of its operating segments recently. Residential and commercial gas distribution has been rising at a solid clip. Too, it maintains a stable regulated electric and gas rate base. What's more, NiSource has been putting an emphasis on operating more efficiently, including increasing its technological capabilities. The use of artificial intelligence (AI) should continue to help drive down costs, resulting in income gains.

The data center business should pay dividends over the long haul. With the increased adoption of AI, the number of data centers being constructed is exploding. These data centers require massive power to operate. One of NiSource's subsidiaries, NIPSCO Generation, LLC plans to build new dispatchable generation facilities to help power data centers. The company also pledged to build two new gas turbine plants with a nominal output of 1,300 megawatts in partnership with a data center developer. These large capital investments are designed to help meet the increased energy demand, which should help drive healthy cash flow well into the next decade.

NiSource shares carry a Timeliness rank of 4 (Below Average). The stock has traded in a tight range since our last full-page review in November and is not an attractive choice for year-ahead relative price performance. Too, capital appreciation potential at the midpoint of our 18-month Target Price Range as well as out to 2029-2031 is not enticing. This issue is best suited for conservative, income-based investors. The yield is above the *Value Line* median, based on NiSource's recently raised dividend.

Kevin P. O'Sullivan *February 20, 2026*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '15, (30¢); '18, ($1.48). Next egs. report due early May. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '25: $1485.9 million, $3.11/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	95

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N.W. NATURAL NYSE-NWN

RECENT PRICE 47.66 | P/E RATIO 16.4 (Trailing: 18.5 Median: 24.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 2/20/26
SAFETY 2 Raised 2/23/24
TECHNICAL 2 Raised 2/20/26
BETA .80 (1.00 = Market)

18-Month Target Price Range

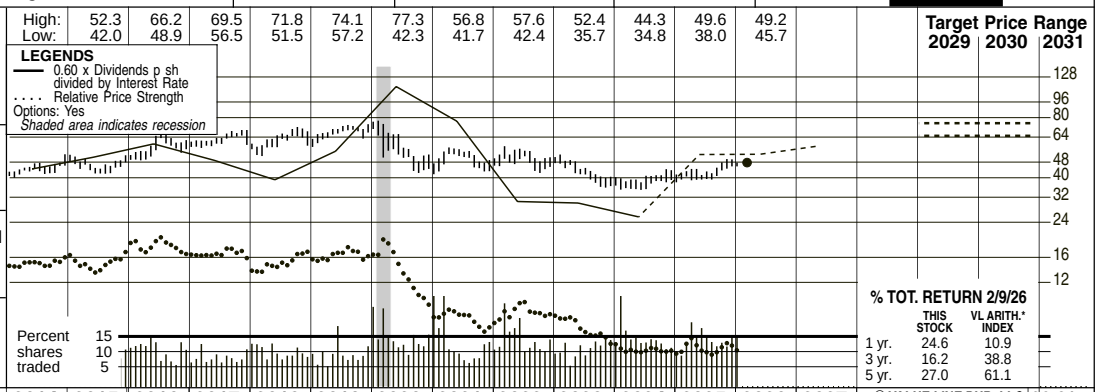
Low-High	Midpoint (% to Mid)
$35-$55	$45 (-5%)

2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+55%)	*15%*
Low	65	(+35%)	*11%*

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	149	169	138
to Sell	100	111	121
Hld's(000)	31667	33159	33403



2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	28.67	*30.60*	*29.00*	*30.20*	Revenues per sh	*31.80*
5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	6.23	*6.50*	*6.55*	*6.80*	"Cash Flow" per sh	*7.45*
2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	2.03	*2.90*	*3.00*	*3.15*	Earnings per sh A	*3.60*
1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	1.95	1.96	*1.97*	*1.97*	Div'ds Decl'd per sh B■	*2.00*
9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	9.81	*9.20*	*9.80*	*10.00*	Cap'l Spending per sh	*10.30*
26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.09	34.12	34.44	*34.25*	*36.25*	*37.05*	Book Value per sh D	*39.40*
26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	40.22	*42.00*	*45.00*	*46.00*	Common Shs Outst'g C	*50.00*
17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	19.0	*14.5*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.05	1.13	.92	.99	*.75*			Relative P/E Ratio	*1.00*
3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	5.1%	4.7%			Avg Ann'l Div'd Yield	*3.3%*
676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	1153.0	*1285*	*1305*	*1390*							Revenues ($mill)	*1590*
58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	78.9	*120*	*135*	*145*							Net Profit ($mill)	*180*
40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.6%	28.3%	*25.0%*	*25.0%*	*25.0%*							Income Tax Rate	*25.0%*
8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	6.8%	*9.3%*	*10.3%*	*10.4%*							Net Profit Margin	*11.3%*
44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	54.8%	*55.0%*	*55.0%*	*55.0%*							Long-Term Debt Ratio	*55.0%*
55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	45.2%	*45.0%*	*45.0%*	*45.0%*							Common Equity Ratio	*45.0%*
1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.3	3064.7	*3560*	*3775*	*3980*							Total Capital ($mill)	*4485*
2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.1	3798.0	*3985*	*4300*	*4500*							Net Plant ($mill)	*4930*
5.1%	NMF	5.8%	5.2%	5.2%	5.1%	4.7%	4.9%	3.9%	*3.5%*	*3.5%*	*4.0%*							Return on Total Cap'l	*4.0%*
6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	5.7%	*8.0%*	*8.0%*	*8.5%*							Return on Shr. Equity	*8.0%*
6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	5.7%	*8.0%*	*8.0%*	*8.5%*							Return on Com Equity	*8.0%*
.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.0%	2.1%	.4%	*2.5%*	*2.0%*	*2.5%*							Retained to Com Eq	*2.5%*
87%	NMF	76%	82%	79%	71%	73%	72%	92%	*68%*	*66%*	*63%*							All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/25
Total Debt $2439 mill. **Due in 5 Yrs** $1175 mill.
LT Debt $2128 mill. **LT Interest** $120 mill.

Pension Assets-12/24 $284.1 mill.
Oblig. $405.6 mill.

Pfd Stock None

Common Stock 41,507,429 shares
as of 10/25/25

MARKET CAP $2.0 billion (Small Cap)

CURRENT POSITION ($MILL.)	2023	2024	9/30/25
Cash Assets	32.9	38.5	32.2
Other	568.5	519.3	403.4
Current Assets	601.4	557.8	435.6
Accts Payable	145.4	133.3	130.5
Debt Due	240.7	200.9	311.2
Other	310.8	314.8	301.1
Current Liab.	696.9	649.0	742.8
Fix. Chg. Cov.	240%	410%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '29-'31
Revenues	1.0%	3.5%	*1.0%*
"Cash Flow"	1.5%	9.0%	*3.5%*
Earnings	1.0%	22.5%	*6.0%*
Dividends	0.5%	0.5%	*.5%*
Book Value	2.0%	4.5%	*2.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	211.7	136.9	370.9	1153.0
2025	494.3	236.2	164.7	*389.8*	*1285*
2026	*455*	*245*	*175*	*430*	*1305*
2027	*470*	*270*	*210*	*440*	*1390*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	d.07	d.71	1.41	2.33
2025	2.28	.01	d.73	*1.34*	*2.90*
2026	*2.30*	*.Nil*	*d.65*	*1.35*	*3.00*
2027	*2.40*	*d.05*	*d.60*	*1.40*	*3.15*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488	.488	.49	1.95
2025	.49	.49	.49	.493	1.96
2026	.493				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to more than 800,000 customers in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Gas margin breakdown: residential, 65%; commercial, 25%; industrial, 6%; other, 4%. Also operates water and wastewater services across six states. Employs 1,452. BlackRock Inc. owns 16.1% of shares; Vanguard, 10.8%; Off./Dir., .9% (4/25 proxy). CEO: Justin B. Palfreyman. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural tends to do best in its first and fourth quarters. That's because these interims cover the coldest months of the year, driving up seasonal demand and use of natural gas for heat in the company's core geographic regions. Favorable utility rate structures, and a greater use of water and wastewater services supplements NWN's revenue boost during these periods.

The fourth quarter of 2025 should have been no different. This was an unusually cold quarter for residents of the utility's Oregon, and relatively newly acquired Texas territories. Higher operating expenses, depreciation, and interest costs probably kept share net slightly below the year-ago figure.

The utility is continuing its market expansion. In an attempt to further grow its revenue base, Northwest is expanding its regulated natural gas business into high population growth states like Texas. The January, 2025 SiEnergy buy was a move in this direction. The company is also acquiring small water and waste water companies in Arizona, Idaho, and California, as well as in its home state of Oregon. Too, Northwest is investing in renewable natural gas projects, as well as hydrogen and carbon capture technologies. These are all intended to reduce costs over the long haul.

The stock price hasn't fared very well since the onset of the pandemic in March, 2020. At that time, the stock reached an all-time high of $77. The issue has been falling since then due to rising interest rates. Utility stocks like NWN are similar to bonds in that their prices decline as interest rates rise. Also, the company is very capital intensive, and therefore requires a lot of debt for financing, and rising interest rates increase interest expense.

Now, however, interest rates are declining. This factor, combined with greater revenue from diversification moves, should elevate the equity's price. In addition, the reliable dividend ought to make these shares attractive to the long-term investor looking for some income. (The regulated utility boasts an impressive track record of 69 consecutive years of dividend increases.)

Jeremy J. Butler *February 20, 2026*

(A) Diluted earnings per share. Excludes nonrecurring items: '09, $0.06; May not sum due to rounding. Next earnings report due in late February.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2024: $184 million, $4.60/share.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	10
Earnings Predictability	35

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 81.77 | P/E RATIO 17.8 (Trailing: 19.1 Median: 21.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 8/22/25
SAFETY 2 New 6/2/17
TECHNICAL 3 Lowered 2/20/26
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$61-$94	$78 (-5%)

2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+55%)	*14%*
Low	90	(+10%)	*6%*

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	188	206	175
to Sell	148	154	163
Hld's(000)	54991	57026	56126

High:	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	78.9	84.0	84.1
Low:	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7	66.4	75.3

LEGENDS
35.00 x Dividends p sh
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2029 | 2030 | 2031

Percent shares traded 21 14 7

% TOT. RETURN 2/9/26

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.1	10.9
3 yr.	14.6	38.8
5 yr.	34.0	61.1

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 9/30/25
Total Debt $3400.2 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $2355.6 mill. **LT Interest** $145.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $5.9 mill.
Pfd Stock None
Pension Assets-12/24 $904.9 mill.
Oblig. $882.1 mill.
Common Stock 59,999,041 shs.
as of 10/24/25
MARKET CAP: $4.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	9/30/25
Cash Assets	18.8	58.0	9.0
Other	746.4	871.9	670.2
Current Assets	765.2	929.9	679.2
Accts Payable	278.1	261.3	121.1
Debt Due	888.9	943.6	1044.6
Other	310.2	253.4	288.2
Current Liab.	1477.2	1458.3	1453.9
Fix. Chg. Cov.	390%	325%	335%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '29-'31
Revenues	1.5%	6.0%	*3.5%*
"Cash Flow"	6.5%	6.0%	*4.5%*
Earnings	7.0%	4.5%	*6.0%*
Dividends	12.0%	7.0%	*2.0%*
Book Value	3.5%	5.0%	*1.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	354.1	340.4	630.8	2083.6
2025	935.2	423.7	379.1	*657*	*2395*
2026	*933*	*452*	*415*	*730*	*2530*
2027	*968*	*487*	*450*	*765*	*2670*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.48	.34	1.34	3.91
2025	1.98	.53	.44	*1.42*	*4.37*
2026	*2.06*	*.60*	*.51*	*1.48*	*4.65*
2027	*2.14*	*.68*	*.58*	*1.55*	*4.95*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66	.66	.66	2.64
2025	.67	.67	.67	.67	2.68
2026	.68				

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	34.80	*39.90*	*40.80*	*41.70*	Revenues per sh	*53.00*
	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	8.68	*9.70*	*10.10*	*10.50*	"Cash Flow" per sh	*11.60*
	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	3.91	*4.37*	*4.65*	*4.95*	Earnings per sh A	*6.00*
	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	2.64	2.68	*2.72*	*2.76*	Div'ds Decl'd per sh B■	*2.95*
	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	11.74	*12.00*	*11.95*	*11.75*	Cap'l Spending per sh	*11.00*
	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	51.85	*53.65*	*54.55*	*54.85*	Book Value per sh	*53.55*
	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	59.88	*60.00*	*62.00*	*64.00*	Common Shs Outst'g C	*75.00*
	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	17.0	*17.3*	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
	1.19	1.18	1.25	1.35	1.11	1.02	1.15	1.00	.90	*.90*	*Value Line*		Relative P/E Ratio	*1.00*
	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	4.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*
	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	2083.6	*2395*	*2530*	*2670*	Revenues ($mill)	*3975*
	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	222.9	*265*	*290*	*315*	Net Profit ($mill)	*450*
	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	14.0%	*18.0%*	*18.0%*	*18.5%*	Income Tax Rate	*21.0%*
	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	10.7%	*11.1%*	*11.5%*	*11.8%*	Net Profit Margin	*11.3%*
	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.9%	43.5%	*42.5%*	*43.0%*	*44.0%*	Long-Term Debt Ratio	*45.0%*
	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.1%	56.5%	*57.5%*	*57.0%*	*56.0%*	Common Equity Ratio	*55.0%*
	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	5489.8	*5600*	*5935*	*6270*	Total Capital ($mill)	*7300*
	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	6645.9	*7200*	*7550*	*7900*	Net Plant ($mill)	*9000*
	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	5.4%	*6.0%*	*6.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.5%*	*9.0%*	Return on Shr. Equity	*11.0%*
	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	7.2%	*8.0%*	*8.5%*	*9.0%*	Return on Com Equity	*11.0%*
	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	2.4%	*3.0%*	*3.5%*	*4.0%*	Retained to Com Eq	*5.5%*
	52%	55%	56%	56%	58%	60%	60%	62%	67%	*61%*	*58%*	*56%*	All Div'ds to Net Prof	*50%*

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 149 Bcf of natural gas supply in 2024, compared to 160 Bcf in 2023. Total volumes delivered by customer (in 2024): transportation, 60.7%; residential, 28.6%; commercial & industrial, 10.1%; other, .6%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 8.0%; officers and directors, 1.2% (4/25 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas probably staged a significant bottom-line turnaround in 2025. Recall that through the first nine months, earnings per share climbed nearly 15%, to $2.95, compared to the prior year's $2.57 tally. That can be traced, in part, to benefits from new rates. Another supporting factor was higher residential sales, mainly reflecting net customer growth in both Oklahoma and Texas. But greater depreciation & amortization expense, given additional capital investments, held back the company's solid performance a bit. Furthermore, employee-related costs rose attributed, to some extent, to planned investments in the workforce. Nevertheless, since it seems that the fourth quarter went fairly well for ONE Gas, full-year profits may have finished at about $4.37 a share. That would indicate a 12% recovery from 2024's $3.91 figure.

Business prospects for 2026 look promising, as well. New rates ought to be one contributing factor. Benefits arising from additional expansion of the customer base should lift results, too. Operating expenses (including those already mentioned) stand to continue to mount, but that is to be expected as the company grows. Consequently, the bottom line may advance around 6%, to $4.65 per share. Concerning 2027, we expect earnings per share to increase at a similar percentage rate, to $4.95, assuming that the business climate is generally favorable.

The quarterly dividend was raised by a penny, to $0.68 a share. ONE Gas says that it intends to keep the average annual dividend growth rate between 1% and 2% through fiscal 2030. We believe that significantly slower increase, relative to earlier this decade, is partially because of climbing operating expenses. In any event, the payout ratio for the pull to 2029-2031 should be reasonable, in the neighborhood of 50%.

ONE Gas shares, though untimely, have some investment merit. Their dividend yield looks respectable compared to the average of *Value Line's* Natural Gas Utility Industry. Too, capital appreciation possibilities over the 3- to 5-year horizon are worthwhile. Consider, also, the 2 (Above Average) Safety rank and high Price Stability score of 85 out of 100.

Frederick L. Harris, III February 20, 2026

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early May. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	100

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 82.87 | P/E RATIO 20.4 (Trailing: 23.5 Median: 21.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$70-$113	$92 (10%)

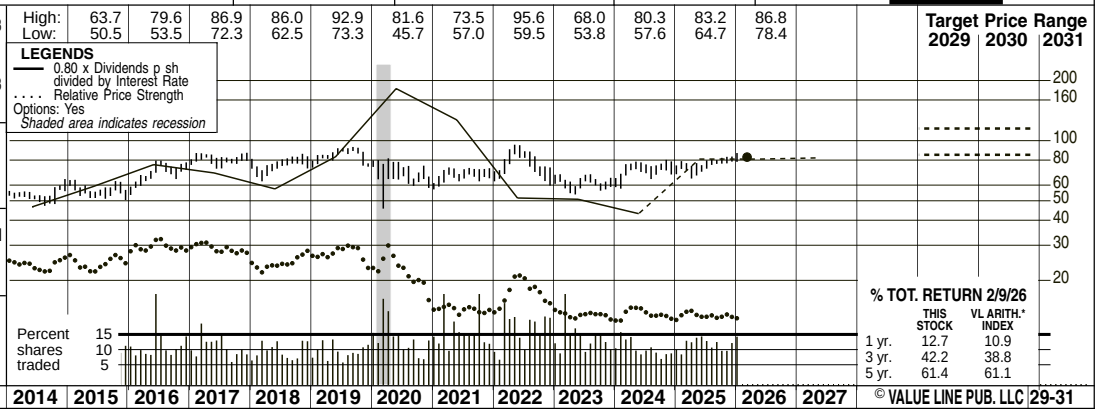
2029-31 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+40%)	*11%*
Low	85	(+5%)	*4%*

Institutional Decisions

	1Q2025	2Q2025	3Q2025
to Buy	181	184	181
to Sell	132	161	129
Hld's(000)	64309	66968	66369

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	© VALUE LINE PUB. LLC	29-31
High:	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	80.3	83.2	86.8								
Low:	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6	64.7	78.4								
	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	75.93	71.22	***50.80***	***45.15***	***46.65***	Revenues per sh	***52.60***
	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.98	8.27	8.88	***8.15***	***8.80***	***9.15***	"Cash Flow" per sh	***10.85***
	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	2.76	***3.65***	***4.10***	***4.45***	Earnings per sh A	***5.65***
	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.46	2.48	2.48	***2.48***	***2.48***	***2.48***	Div'ds Decl'd per sh B■†	***2.70***
	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	13.18	***10.40***	***10.25***	***10.15***	Cap'l Spending per sh	***9.90***
	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	45.57	46.25	48.82	***54.45***	***55.55***	***56.95***	Book Value per sh	***63.70***
	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	71.78	***73.00***	***74.00***	***75.00***	Common Shs Outst'g C	***77.00***
	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.0	25.9	***20.8***	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***18.0***
	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.61	1.35	***1.08***			Relative P/E Ratio	***1.00***
	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%	3.5%	3.3%			Avg Ann'l Div'd Yield	***3.0%***
							2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5434.0	5112.4	***3710***	***3340***	***3500***	Revenues ($mill)	***4050***
							152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	198.8	***265***	***305***	***335***	Net Profit ($mill)	***435***
							33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	- -	21.2%	15.1%	***20.0%***	***20.0%***	***20.0%***	Income Tax Rate	***20.0%***
							6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	3.9%	***7.1%***	***9.1%***	***9.6%***	Net Profit Margin	***10.7%***
							48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	59.0%	58.2%	55.4%	***55.0%***	***55.0%***	***55.0%***	Long-Term Debt Ratio	***56.0%***
							51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	41.0%	41.8%	44.6%	***45.0%***	***45.0%***	***45.0%***	Common Equity Ratio	***44.0%***
							3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7462.1	7919.9	7852.5	***8600***	***9030***	***9480***	Total Capital ($mill)	***10975***
							4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	8109.1	***8600***	***9025***	***9475***	Net Plant ($mill)	***10970***
							5.8%	5.8%	5.2%	5.4%	5.3%	3.4%	NMF	3.8%	4.4%	***5.0%***	***5.5%***	***6.0%***	Return on Total Cap'l	***6.5%***
							9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	5.7%	***6.5%***	***7.5%***	***8.0%***	Return on Shr. Equity	***9.0%***
							9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.6%	5.7%	***6.5%***	***6.5%***	***8.0%***	Return on Com Equity	***9.0%***
							4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	.6%	***2.0%***	***3.0%***	***3.5%***	Retained to Com Eq	***4.5%***
							55%	53%	55%	54%	54%	69%	NMF	116%	89%	***68%***	***60%***	***55%***	All Div'ds to Net Prof	***48%***



CAPITAL STRUCTURE as of 9/30/25
Total Debt $3507.1 mill. **Due in 5 Yrs** $2623 mill.
LT Debt $3507.1 mill. **LT Interest** $180 mill. (47% of Cap'l)

Leases, Uncapitalized Annual rentals $23.7 mill.
Pension Assets-12/24 $1158.0 mill. **Oblig.** $1237.3 mill.

Pfd Stock None

Common Stock 72,182,840 shs. **as of 10/31/25**

MARKET CAP: $6.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2023	2024	9/30/25
Cash Assets	106.5	363.8	778.6
Other	1774.6	1100.7	464.9
Current Assets	1881.1	1464.5	1243.5
Accts Payable	346.9	331.8	118.9
Debt Due	671.1	710.0	- -
Other	666.8	790.3	685.8
Current Liab.	1684.8	1832.1	804.7
Fix. Chg. Cov.	145%	310%	365%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '22-'24 to '29-'31
Revenues	5.5%	6.0%	*-4.5%*
"Cash Flow"	-1.5%	-4.5%	*6.5%*
Earnings	-15.0%	-31.0%	- -
Dividends	6.5%	3.5%	*1.5%*
Book Value	4.5%	2.5%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	1603.3	1293.6	1169.5	1387.6	5434.0
2024	1581.0	1182.2	1079.2	1307.6	5112.4
2025	1296.5	1120.4	316.9	***976.2***	***3710***
2026	***1040***	***750***	***500***	***1050***	***3340***
2027	***1050***	***800***	***550***	***1100***	***3500***

Calendar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2023	.67	.40	.04	1.02	2.13
2024	1.22	.25	- -	1.28	2.76
2025	1.65	.53	.06	***1.41***	***3.65***
2026	***2.00***	***.55***	***.10***	***1.45***	***4.10***
2027	***2.10***	***.65***	***.15***	***1.55***	***4.45***

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62	.62	.62	.62	2.48
2025	.62	.62	.62	.62	2.48
2026					

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Completed the registered public offering of Centuri Group shares 9/25. Southwest Gas is a regulated gas distributor serving 2.3 million customers in Arizona, Nevada, and California. 2024 revenue mix: residential 68%; small commercial, 20%; large commercial and industrial, 5%; transportation, 7%. Southwest has 2,435 employees as of 12/31/24. Off. & dir. own .5% of common stock; Carl C. Icahn, 13.4%; BlackRock, 12.9%; The Vanguard Group, 10.1%; Corvex Management, 6.6% (3/25 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holdings has completed its seperation from Centuri. During the second half of 2025, the company completed the previously announced registered public offering of Centuri Holdings stock. Centuri was previously the company's Utility Infrastructure Services division. A lion's share of the $525 million in proceeds were used to pay down debt under a term loan and revolving credit facility. Remaining proceeds are likely to be applied to help support Southwest Gas' capital projects (see below), dividends payments, and balance sheet health.

Year-over-year comparisons in 2025 and 2026 are not meaningful, but there are various catalysts. (The company will probably provide 2026 guidance during its fourth-quarter earnings presentation, which was expected after we went to press with this report.) The biggest and most immediate is the likelihood of a favorable outcome on the regulatory front. Management was expected to file cases in Arizona and Nevada in early 2026, seeking the approval for higher rates, as well as alternative forms of rate-making. Also, in the early part of the new year, Southwest likely implemented new rates for energy supplied to customers in California. With ample capital in place, this natural gas regulated business possesses the means to support expansion in service areas. Specifically, robust energy demand has the potential to power growth at Great Basin (also known as the Northern Nevada interstate pipeline) through its expansion.

A reduction in debt and the ensuing improvement across the company's risk profile ought to help in many ways. Specifically, it has enhanced credit ratings, which ought to aid in lowering borrowing costs, and boost access to capital. This should come in handy if the company gets approval for the $1.7 billion Great Basin Gas Transmission expansion project (expected in 2028.) Too, we think the company will be better able to hike its dividend in the long term.

Our projections suggest Southwest shares, unranked due to the Centuri transaction, hold limited appeal over the 3- to 5-year time frame. The issue may attract income seekers, however, thanks to the 3.0% dividend yield.

Dominic B. Silva *February 20, 2026*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due February 23rd. **(B)** Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions. **(D)** Totals may not sum due to rounding. **(E)** Rank suspended 11/17/2023 for reported spin-off of the Centuri Group.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	NMF
Earnings Predictability	5

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UGI Utilities, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.35%
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.33%
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.68%
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group (3)	0.06%
5.	Adjusted Bond Yield	5.74%
6.	Equity Risk Premium (4)	4.94% - 5.39%
7.	Risk Premium Derived Common Equity Cost Rate	10.68% - 11.13%

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 19 and 20 of this Schedule).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.33% from page 14 of this Schedule.

(3) Adjustment to reflect the A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 15 of this Schedule. The 0.06% upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 0.18% = 0.06%) as derived from page 14 of this Schedule.

(4) From page 17 of this Schedule.

UGI Utilities, Inc.
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Mar-2026	5.48 %	5.82 %	5.99 %
Feb-2026	5.30	5.61	5.78
Jan-2026	5.34	5.68	5.86
Average	5.37 %	5.70 %	5.88 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.33 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.18 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

UGI Utilities, Inc.
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Six Natural Gas Companies

Proxy Group of Six Natural Gas Companies	Moody's Long-Term Issuer Rating March 2026		Standard & Poor's Long-Term Issuer Rating March 2026	
	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A2	6.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A/A-	6.5
ONE Gas, Inc.	A3	7.0	A-	7.0
Southwest Gas Holdings, Inc.	Baa1	8.0	BBB+	8.0
Average	A3	7.0	A-	7.3
UGI Utilities, Inc.	A3	7.0	NR	- -

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 16 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

UGI Utilities, Inc.
Judgment of Equity Risk Premium for the
Proxy Group of Six Natural Gas Companies

Line No.		Proxy Group of Six Natural Gas Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	4.97% - 6.31%
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	5.13%
3.	Predicted Equity Risk Premium Based on Regression Analysis of 866 Fully-Litigated Natural Gas Cases (3)	4.73%
4.	Average equity risk premium	4.94% - 5.39%

Notes: (1) From page 18 of this Schedule.
(2) From page 21 of this Schedule.
(3) From page 22 of this Schedule.

UGI Utilities, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Companies
1.	Kroll Equity Risk Premium (1)	6.17%
2.	Regression on Kroll Risk Premium Data (2)	6.87%
3.	Kroll Equity Risk Premium based on PRPM (3)	6.71%
4	Equity Risk Premium Based on Value Line Summary and Index (4)	5.86%
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	13.83%
6.	Conclusion of Equity Risk Premium	7.89%
7.	Adjusted Beta (6)	0.63 0.80
8.	Forecasted Equity Risk Premium	4.97% - 6.31%

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2025.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2025 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.35% (from page 13 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through March 2026.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.35% (from page 13 of this Schedule) from the projected 3-5 year total annual market return of 11.21% (described fully in note 1 on page 25 of this Schedule).

(5) Using data from Bloomberg Professional Services, Value Line, and S&P Global Market Intelligence for the S&P 500, an expected total return of 19.18% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.35% results in an expected equity risk premium of 13.83%.

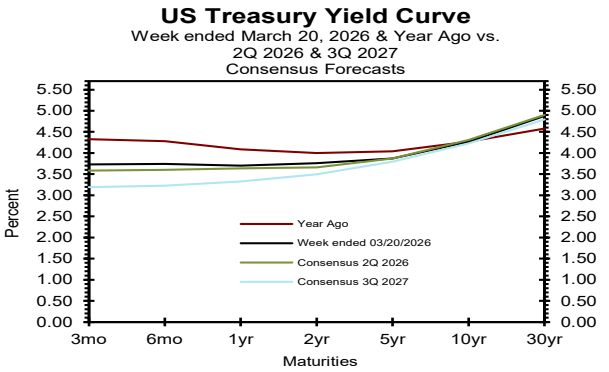
(6) Average of mean and median beta from pages 23 and 24 of this Schedule.

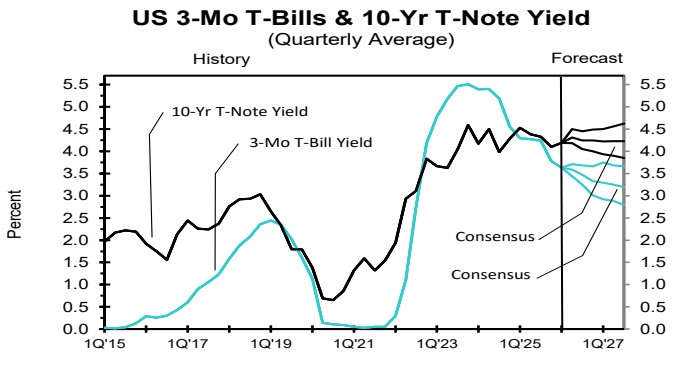
Sources of Information:
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2025, April 1, 2026
S&P Capital IQ
Bloomberg Professional Services

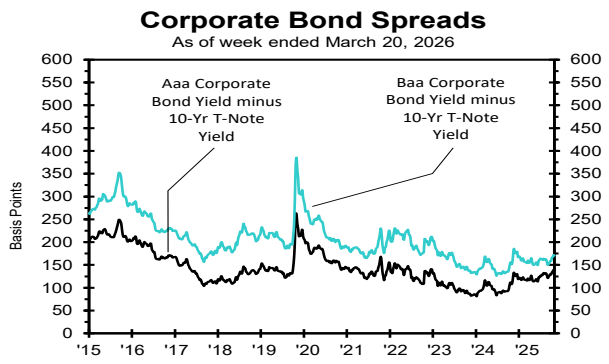
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

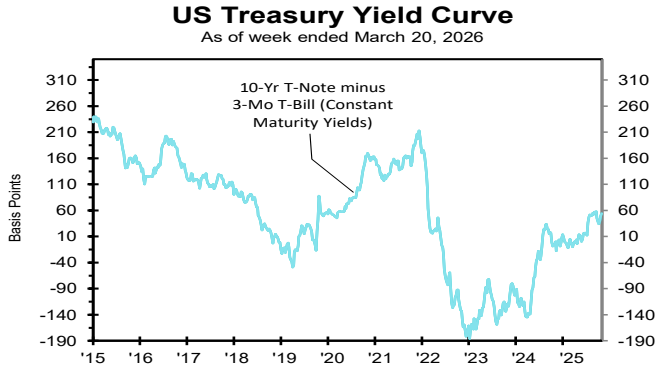
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	Mar 20	Mar 13	Mar 6	Feb 27	Feb	Jan	Dec	1Q 2026*	2026	2026	2026	2027	2027	2027
Federal Funds Rate	3.64	3.64	3.64	3.64	3.64	3.64	3.72	3.64	3.6	3.5	3.3	3.3	3.2	3.2
Prime Rate	6.75	6.75	6.75	6.75	6.75	6.75	6.83	6.75	6.7	6.5	6.4	6.4	6.4	6.3
SOFR	3.64	3.65	3.68	3.67	3.67	3.67	3.79	3.66	3.6	3.5	3.4	3.4	3.3	3.2
Commercial Paper, 1-mo.	3.75	3.72	3.68	3.64	3.63	3.62	3.73	3.66	3.6	3.5	3.4	3.4	3.3	3.2
Treasury bill, 3-mo.	3.73	3.71	3.71	3.68	3.69	3.67	3.68	3.69	3.6	3.5	3.3	3.3	3.3	3.2
Treasury bill, 6-mo.	3.74	3.69	3.68	3.61	3.60	3.59	3.63	3.64	3.6	3.5	3.4	3.3	3.3	3.2
Treasury bill, 1 yr.	3.70	3.61	3.56	3.51	3.48	3.51	3.54	3.55	3.6	3.5	3.5	3.4	3.4	3.3
Treasury note, 2 yr.	3.76	3.65	3.53	3.42	3.47	3.54	3.50	3.57	3.7	3.6	3.6	3.5	3.5	3.5
Treasury note, 5 yr.	3.87	3.80	3.67	3.58	3.68	3.78	3.70	3.77	3.9	3.8	3.8	3.8	3.8	3.8
Treasury note, 10 yr.	4.27	4.21	4.10	4.02	4.13	4.21	4.14	4.19	4.3	4.2	4.2	4.2	4.2	4.2
Treasury note, 30 yr.	4.88	4.83	4.73	4.68	4.76	4.84	4.80	4.81	4.9	4.8	4.8	4.8	4.8	4.8
Corporate Aaa bond	5.64	5.60	5.46	5.36	5.42	5.48	5.44	5.50	5.5	5.4	5.5	5.2	5.2	5.4
Corporate Baa bond	5.98	5.93	5.78	5.68	5.72	5.77	5.77	5.80	6.3	6.2	6.4	6.1	6.1	6.3
State & Local bonds	4.09	4.03	3.97	3.87	3.92	4.04	4.11	4.02	4.5	4.5	4.5	4.5	4.5	4.5
Home mortgage rate	6.22	6.11	6.00	5.98	6.05	6.11	6.20	6.11	6.3	6.2	6.2	6.2	6.2	6.1
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2024	2024	2024	2025	2025	2025	2025	2026**	2026	2026	2026	2027	2027	2027
Fed's AFE $ Index	117.2	114.7	117.7	119.6	112.7	110.9	112.2	110.8	111.9	111.5	111.1	111.1	111.1	111.0
Real GDP	3.6	3.3	1.9	-0.6	3.8	4.4	0.7	2.5	1.8	1.8	2.0	2.1	2.1	2.1
GDP Price Index	2.6	1.8	2.4	3.6	2.1	3.8	3.8	2.7	3.4	2.6	2.6	2.5	2.3	2.3
Consumer Price Index	2.7	1.3	3.2	3.7	1.7	3.1	2.9	2.8	4.6	2.2	2.5	2.5	2.2	2.4
PCE Price Index	2.6	1.7	2.5	3.4	2.1	2.8	2.9	3.0	3.9	2.4	2.4	2.4	2.2	2.3

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 1Q 2026 based on historical data through the week ended March 20. **Data for 1Q 2026 for the Fed's AFE $ Index based on data through the week ended March 20. Figures for 1Q 2026 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the March 2026 survey.









Long-Range Survey:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2027 through 2031 and averages for the five-year periods 2027-2031 and 2032-2036. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2027	2028	2029	2030	2031	2027-2031	2032-2036
1. Federal Funds Rate	**CONSENSUS**	**3.2**	**3.3**	**3.3**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.5	3.6	3.7	3.5	3.5	3.5	3.5
	Bottom 10 Average	2.9	2.9	2.9	2.8	2.8	2.8	2.8
2. Prime Rate	**CONSENSUS**	**6.3**	**6.4**	**6.5**	**6.2**	**6.3**	**6.3**	**6.3**
	Top 10 Average	6.6	6.7	6.8	6.5	6.5	6.6	6.6
	Bottom 10 Average	6.1	6.1	6.1	6.0	6.0	6.0	6.0
3. SOFR	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.1**	**3.1**	**3.2**	**3.2**
	Top 10 Average	3.5	3.6	3.6	3.3	3.3	3.5	3.5
	Bottom 10 Average	3.0	3.0	3.0	2.8	2.8	2.9	2.9
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.3**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**	**3.2**
	Top 10 Average	3.4	3.5	3.5	3.6	3.6	3.5	3.4
	Bottom 10 Average	3.1	3.1	3.1	2.9	2.9	3.0	3.0
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.2**	**3.2**	**3.3**	**3.1**	**3.1**	**3.2**	**3.2**
	Top 10 Average	3.5	3.5	3.6	3.3	3.3	3.4	3.5
	Bottom 10 Average	2.9	2.9	2.9	2.8	2.8	2.8	2.9
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.2**	**3.3**	**3.3**	**3.1**	**3.1**	**3.2**	**3.2**
	Top 10 Average	3.5	3.6	3.6	3.3	3.3	3.5	3.5
	Bottom 10 Average	2.9	3.0	3.0	2.9	2.9	2.9	2.9
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.3**	**3.4**	**3.4**	**3.2**	**3.2**	**3.3**	**3.3**
	Top 10 Average	3.6	3.7	3.7	3.4	3.4	3.5	3.5
	Bottom 10 Average	3.0	3.1	3.1	3.0	3.0	3.0	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.5**	**3.6**	**3.6**	**3.4**	**3.3**	**3.5**	**3.4**
	Top 10 Average	3.8	3.9	3.9	3.7	3.6	3.8	3.7
	Bottom 10 Average	3.1	3.2	3.2	3.1	3.1	3.2	3.1
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.8**	**3.9**	**3.9**	**3.7**	**3.7**	**3.8**	**3.8**
	Top 10 Average	4.0	4.2	4.2	4.0	3.9	4.1	4.2
	Bottom 10 Average	3.5	3.5	3.5	3.5	3.4	3.5	3.4
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.2**	**4.3**	**4.2**	**4.1**	**4.1**	**4.2**	**4.2**
	Top 10 Average	4.5	4.7	4.7	4.5	4.4	4.6	4.6
	Bottom 10 Average	3.9	3.8	3.8	3.8	3.8	3.8	3.8
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.6**	**4.6**	**4.6**	**4.5**	**4.4**	**4.6**	**4.5**
	Top 10 Average	4.9	5.0	5.1	4.9	4.8	4.9	4.9
	Bottom 10 Average	4.3	4.3	4.2	4.2	4.1	4.2	4.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.4**	**5.5**	**5.4**	**5.3**	**5.2**	**5.3**	**5.3**
	Top 10 Average	5.7	5.8	5.8	5.6	5.5	5.7	5.7
	Bottom 10 Average	5.1	5.2	5.1	5.0	5.0	5.1	5.0
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.1**	**6.2**	**6.2**	**6.1**	**6.0**	**6.1**	**6.1**
	Top 10 Average	6.5	6.6	6.6	6.4	6.3	6.5	6.5
	Bottom 10 Average	5.9	5.9	5.8	5.8	5.7	5.8	5.8
14. State & Local Bonds Yield	**CONSENSUS**	**4.4**	**4.5**	**4.5**	**4.3**	**4.2**	**4.4**	**4.3**
	Top 10 Average	4.6	4.7	4.7	4.5	4.4	4.6	4.5
	Bottom 10 Average	4.3	4.3	4.3	4.2	4.1	4.3	4.2
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.2**	**6.2**	**6.1**	**6.0**	**6.1**	**6.1**
	Top 10 Average	6.6	6.6	6.7	6.5	6.4	6.5	6.5
	Bottom 10 Average	5.9	5.8	5.7	5.7	5.7	5.7	5.8
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**110.9**	**110.2**	**109.5**	**110.0**	**110.2**	**110.1**	**108.9**
	Top 10 Average	111.9	111.6	111.4	111.1	111.6	111.5	110.5
	Bottom 10 Average	110.0	109.0	108.3	108.9	109.0	109.0	107.2
		Year-Over-Year, % Change					Five-Year Averages	
		2027	2028	2029	2030	2031	2027-2031	2032-2036
B. Real GDP	**CONSENSUS**	**2.0**	**2.1**	**2.1**	**1.9**	**1.8**	**2.0**	**1.9**
	Top 10 Average	2.3	2.3	2.4	2.2	2.2	2.3	2.1
	Bottom 10 Average	1.8	1.8	1.8	1.6	1.6	1.7	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.4**	**2.4**	**2.2**	**2.0**	**2.3**	**2.2**
	Top 10 Average	2.6	2.6	2.7	2.5	2.2	2.5	2.4
	Bottom 10 Average	2.1	2.0	1.9	1.9	1.9	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.4**	**2.3**	**2.3**	**2.1**	**2.3**	**2.3**
	Top 10 Average	2.7	2.7	2.7	2.6	2.2	2.6	2.5
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.1
E. PCE Price Index	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.2**	**2.0**	**2.2**	**2.2**
	Top 10 Average	2.6	2.5	2.6	2.4	2.1	2.4	2.4
	Bottom 10 Average	2.0	2.0	2.0	1.9	1.9	2.0	2.0

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
1.	Historical Equity Risk Premium (1)	4.23%
2.	Regression of Historical Equity Risk Premium (2)	4.94%
3	Forecasted Equity Risk Premium Based on PRPM (3)	4.91%
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	6.45%
5.	Average Equity Risk Premium (5)	5.13%

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2025. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

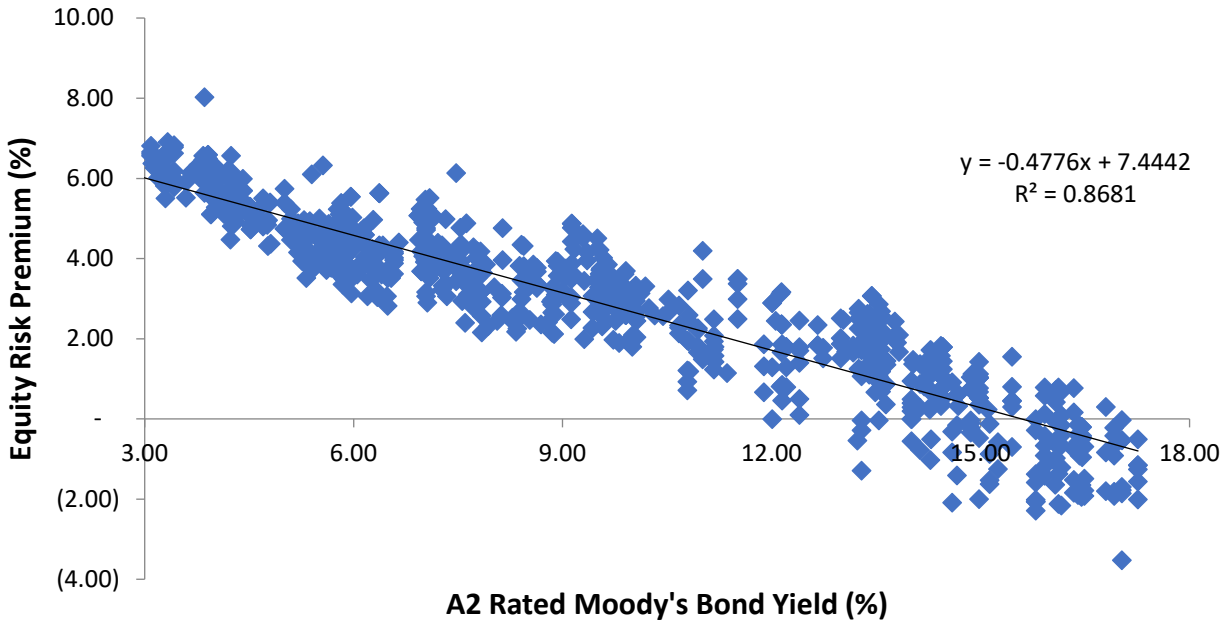
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2025 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.68% (from line 3, page 13 of this Schedule).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - March 2026.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 12.13% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.68%, calculated on line 3 of page 13 of this Schedule, results in an equity risk premium of 6.45% (12.13% - 5.68% = 6.45%).

(5) Average of lines 1 through 4.

UGI Utilities, Inc.
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.4442 %	-0.4776	5.68 %	4.73 %

Notes:

(1) From line 3 of page 13 of this Schedule.

Source of Information: Regulatory Research Associates.

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	0.42	0.61	8.71 %	4.75 %	10.06 %	10.91 %	10.49 %
New Jersey Resources Corporation	0.75	0.38	0.57	8.71	4.75	9.71	10.65	10.18
NiSource Inc.	0.85	0.55	0.70	8.71	4.75	10.84	11.50	11.17
Northwest Natural Holding Company	0.80	0.46	0.63	8.71	4.75	10.24	11.04	10.64
ONE Gas, Inc.	0.75	0.43	0.59	8.71	4.75	9.89	10.78	10.33
Southwest Gas Holdings, Inc.	0.80	0.55	0.67	8.71	4.75	10.58	11.30	10.94
Mean			0.63			10.22 %	11.03 %	10.63 %
Median			0.62			10.15 %	10.98 %	10.57 %
Average of Mean and Median			0.63			10.19 %	11.01 %	10.60 %

Notes on page 25 of this Schedule.

UGI Utilities, Inc.
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Companies

Proxy Group of Six Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Market Risk Premium (1)	[3] Risk-Free Rate (2)	[4] Traditional CAPM Cost Rate	[5] ECAPM Cost Rate	[6] Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	8.71 %	4.75 %	11.72 %	12.15 %	11.93 %
New Jersey Resources Corporation	0.75	8.71	4.75	11.28	11.82	11.55
NiSource Inc.	0.85	8.71	4.75	12.15	12.48	12.31
Northwest Natural Holding Company	0.80	8.71	4.75	11.72	12.15	11.93
ONE Gas, Inc.	0.75	8.71	4.75	11.28	11.82	11.55
Southwest Gas Holdings, Inc.	0.80	8.71	4.75	11.72	12.15	11.93
Mean	0.79			11.64 %	12.10 %	11.87 %
Median	0.80			11.72 %	12.15 %	11.93 %
Average of Mean and Median	0.80			11.68 %	12.13 %	11.90 %

Notes on page 25 of this Schedule.

UGI Utilities, Inc.
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

Measure 1: Kroll Arithmetic Mean MRP (1926-2025)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2025:	12.35 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99
MRP based on Kroll Historical Data:	7.37 %

Measure 2: Application of a Regression Analysis to Kroll Historical Data
(1926-2025) 7.77 %

Measure 3: Application of the PRPM to Kroll Historical Data
(January 1926 - March 2026) 7.51 %

Measure 4: Value Line Projected MRP (Thirteen weeks ending April 3, 2026)

Total projected return on the market 3-5 years hence*:	11.21 %
Risk-Free Rate (see note 2):	4.75
MRP based on Value Line Summary & Index:	6.46 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	19.18 %
Risk-Free Rate (see note 2):	4.75
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	14.43 %

Average of all MRP Measures: 8.71 %

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts (See pages 19 and 20 of this Schedule). The projection of the risk-free rate is illustrated below:

Second Quarter 2026	4.90 %
Third Quarter 2026	4.80
Fourth Quarter 2026	4.80
First Quarter 2027	4.80
Second Quarter 2027	4.80
Third Quarter 2027	4.80
2027-2031	4.60
2032-2036	4.50
	4.75 %

(3) Average of CAPM and ECAPM cost rates.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, December 1, 2025, April 1, 2026
Kroll 2023 SBBI® Yearbook
S&P Capital IQ
Bloomberg Professional Services

UGI Utilities, Inc.
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Six Natural Gas Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of six natural gas companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.48 - 0.80 and residual standard error of the regression range of 2.4671 - 2.9423 of the proxy group of six natural gas companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1188. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1188 = \frac{2.7047}{\sqrt{518}} = \frac{2.7047}{22.7596}$$

Source of Information: Value Line Proprietary Database, March 2026.
Value Line Investment Survey (Standard Edition).

UGI Utilities, Inc.
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Six Natural Gas Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.80	0.62	2.2250	0.0664
New Jersey Resources Corporation	0.75	0.61	2.6581	0.0793
NiSource Inc.	0.85	0.74	2.4083	0.0718
Northwest Natural Holding Company	0.75	0.61	2.7817	0.0830
ONE Gas, Inc.	0.75	0.60	3.0607	0.0913
Southwest Gas Holdings, Inc.	0.80	0.66	3.0946	0.0923
Average	0.78	0.64	2.7047	0.0807
Beta Range (+/- 2 std. Devs. of Beta)	0.48	0.80		
2 std. Devs. of Beta	0.16			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.4671	2.9423		
Std. dev. of the Res. Std. Err.	0.1188			
2 std. devs. of the Res. Std. Err.	0.2376			

Source of Information: Value Line Proprietary Database, March 2026.

UGI Utilities, Inc.
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Companies

Proxy Group of Thirteen Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Abbott Laboratories	0.75	0.58	2.6445	0.0789
Casella Waste Systems Inc.	0.80	0.68	2.9238	0.0872
Cisco Systems Inc.	0.85	0.77	2.7439	0.0818
Costco Wholesale Corporation	0.80	0.68	2.6916	0.0803
Jack Henry & Associates Inc.	0.80	0.66	2.8239	0.0842
Labcorp Holdings Inc.	0.85	0.73	2.7675	0.0825
Monster Beverage Corporation	0.70	0.50	2.7937	0.0833
O'Reilly Automotive Inc.	0.75	0.58	2.8811	0.0859
Quest Diagnostics Inc.	0.70	0.49	2.8367	0.0846
RLI Corporation	0.80	0.63	2.6759	0.0798
Sysco Corporation	0.85	0.76	2.6277	0.0784
W.R. Berkley Corporation	0.85	0.74	2.6874	0.0801
Walmart Inc.	0.75	0.58	2.7409	0.0817
Average	0.79	0.64	2.7568	0.0822
Proxy Group of Six Natural Gas	0.78	0.64	2.7047	0.0807

Source of Information: Value Line Proprietary Database, March 2026.

UGI Utilities, Inc.
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Companies

Principal Methods	Proxy Group of Thirteen Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	9.71%
Risk Premium Model (RPM) (2)	11.74% - 12.76%
Capital Asset Pricing Model (CAPM) (3)	10.84% - 11.89%
Mean	10.76% - 11.45%
Median	10.84% - 11.89%
Average of Mean and Median	10.80% - 11.67%

Notes:
(1) From page 30 of this Schedule.
(2) From page 31 of this Schedule.
(3) From pages 34 and 35 of this Schedule.

UGI Utilities, Inc.
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Companies

Proxy Group of Thirteen Non-Price Regulated Companies	[1] Average Dividend Yield	[2] Value Line Projected Five Year Growth in EPS	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth Rate in EPS (1)	[6] Adjusted Dividend Yield	[7] Indicated Common Equity Cost Rate (2)
Abbott Laboratories	2.24 %	6.50 %	11.10 %	10.07 %	9.22 %	2.34 %	11.56 %
Casella Waste Systems Inc.	-	11.00	NA	(2.70)	11.00	-	NA
Cisco Systems Inc.	2.15	7.00	7.80	7.23	7.34	2.23	9.57
Costco Wholesale Corporation	0.53	10.00	10.00	9.58	9.86	0.56	10.42
Jack Henry & Associates Inc.	1.43	11.00	10.00	10.00	10.33	1.50	11.83
Labcorp Holdings Inc.	1.06	5.50	8.30	8.23	7.34	1.10	8.44
Monster Beverage Corporation	-	13.00	13.50	11.48	12.66	-	NA
O'Reilly Automotive Inc.	-	10.50	14.00	12.99	12.50	-	NA
Quest Diagnostics Inc.	1.77	6.50	7.30	8.20	7.33	1.83	9.16
RLI Corporation	1.07	3.50	NA	NA	3.50	1.09	4.59 (3)
Sysco Corporation	2.61	7.00	7.00	6.03	6.68	2.70	9.38
W.R. Berkley Corporation	0.52	11.50	5.60	5.59	7.56	0.54	8.10
Walmart Inc.	0.81	10.00	9.30	8.81	9.37	0.85	10.22
	NA = Not Available					Mean	9.85 %
						Median	9.57 %
						Average of Mean and Median	9.71 %

Notes:

(1) Average of columns 2 through 4 excluding negative growth rates and extreme positive values.

(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 3/31/2026. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey.
www.zacks.com, Downloaded on 3/31/2026
S&P Capital IQ

UGI Utilities, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Thirteen Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.20%
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	0.25%
3.	Adjusted Bond Yield	6.45%
4.	Equity Risk Premium (3)	5.29% - 6.31%
5.	Risk Premium Derived Common Equity Cost Rate	11.74% - 12.76%

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated December 1, 2025, April 1, 2026 (see pages 19 and 20 of this Schedule). The estimates are detailed below.

Second Quarter 2026	6.30 %
Third Quarter 2026	6.20
Fourth Quarter 2026	6.40
First Quarter 2027	6.10
Second Quarter 2027	6.10
Third Quarter 2027	6.30
2027-2031	6.10
2032-2036	6.10
Average	6.20 %

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending March 2026. To reflect the A2 average rating of the Non-Price Regulated Proxy Group, the yield on the Baa corporate bond must be adjusted by the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Mar-26	5.78 %	6.04 %	0.26 %
Feb-26	5.57	5.81	0.24
Jan-26	5.63	5.88	0.25
		Average yield spread	0.25 %

(3) From page 33 of this Schedule.

UGI Utilities, Inc.
Comparison of Long-Term Issuer Ratings for the
and Proxy Group of Thirteen Non-Price Regulated Companies

Proxy Group of Thirteen Non-Price Regulated Companies	Moody's Long-Term Issuer Rating March 2026		Standard & Poor's Long-Term Issuer Rating March 2026	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Laboratories	Aa3	4.0	A+	5.0
Casella Waste Systems Inc.	NA	--	BB	12.0
Cisco Systems Inc.	A1	5.0	AA-	4.0
Costco Wholesale Corporation	Aa3	4.0	AA	3.0
Jack Henry & Associates Inc.	NA	--	NA	--
Labcorp Holdings Inc.	NA	--	BBB	9.0
Monster Beverage Corporation	NA	--	NA	--
O'Reilly Automotive Inc.	Baa1	8.0	BBB	9.0
Quest Diagnostics Inc.	Baa1	8.0	BBB+	8.0
RLI Corporation	Baa2	9.0	BBB	9.0
Sysco Corporation	Baa2	9.0	BBB	9.0
W.R. Berkley Corporation	Baa1	8.0	A-	7.0
Walmart Inc.	Aa2	3.0	AA	3.0
Proxy Group of Thirteen Non-Price Regulated Companies Average	A2	6.4	A-	7.1

Notes:
(1) From page 16 of this Schedule.

Source of Information:
Bloomberg Professional Services.

UGI Utilities, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Thirteen Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.17%
2.	Regression on Kroll Risk Premium Data (2)	6.87%
3.	Kroll Equity Risk Premium based on PRPM (3)	6.71%
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.86%
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	13.83%
6.	Conclusion of Equity Risk Premium	7.89%
7.	Adjusted Beta (6)	0.67 0.80
8.	Forecasted Equity Risk Premium	5.29% - 6.31%

Notes:

(1) From note 1 of page 18 of this Schedule.
(2) From note 2 of page 18 of this Schedule.
(3) From note 3 of page 18 of this Schedule.
(4) From note 4 of page 18 of this Schedule.
(5) From note 5 of page 18 of this Schedule.
(6) Average of mean and median beta from pages 34 and 35 of this Schedule.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts, December 1, 2025, April 1, 2026
Bloomberg Professional Services.

UGI Utilities, Inc.

Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the Proxy Group of Six Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Thirteen Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Abbott Laboratories	0.75	0.55	0.65	8.71 %	4.75 %	10.41 %	11.17 %	10.79 %
Casella Waste Systems Inc.	0.80	0.54	0.67	8.71	4.75	10.58	11.30	10.94
Cisco Systems Inc.	0.85	0.93	0.89	8.71	4.75	12.50	12.74	12.62 (4)
Costco Wholesale Corporation	0.80	0.68	0.74	8.71	4.75	11.19	11.76	11.48
Jack Henry & Associates Inc.	0.80	0.42	0.61	8.71	4.75	10.06	10.91	10.49
Labcorp Holdings Inc.	0.85	0.58	0.71	8.71	4.75	10.93	11.56	11.25
Monster Beverage Corporation	0.70	0.57	0.64	8.71	4.75	10.32	11.11	10.71
O'Reilly Automotive Inc.	0.75	0.46	0.60	8.71	4.75	9.97	10.84	10.41
Quest Diagnostics Inc.	0.70	0.46	0.58	8.71	4.75	9.80	10.71	10.26
RLI Corporation	0.80	0.48	0.64	8.71	4.75	10.32	11.11	10.71
Sysco Corporation	0.85	0.44	0.65	8.71	4.75	10.41	11.17	10.79
W.R. Berkley Corporation	0.85	0.56	0.70	8.71	4.75	10.84	11.50	11.17
Walmart Inc.	0.75	0.78	0.77	8.71	4.75	11.45	11.95	11.70
		Mean	0.68			10.68 %	11.37 %	10.89 %
		Median	0.65			10.41 %	11.17 %	10.79 %
		Average of Mean and Median	0.67			10.55 %	11.27 %	10.84 %

Notes:

(1) From note 1 of page 25 of this Schedule.

(2) From note 2 of page 25 of this Schedule.

(3) Average of CAPM and ECAPM cost rates.

(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

UGI Utilities, Inc.

Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the Proxy Group of Six Natural Gas Companies

Proxy Group of Thirteen Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Market Risk Premium (1)	[3] Risk-Free Rate (2)	[4] Traditional CAPM Cost Rate	[5] ECAPM Cost Rate	[6] Indicated Common Equity Cost Rate (3)
Abbott Laboratories	0.75	8.71 %	4.75 %	11.28 %	11.82 %	11.55 %
Casella Waste Systems Inc.	0.80	8.71	4.75	11.72	12.15	11.93
Cisco Systems Inc.	0.85	8.71	4.75	12.15	12.48	12.31
Costco Wholesale Corporation	0.80	8.71	4.75	11.72	12.15	11.93
Jack Henry & Associates Inc.	0.80	8.71	4.75	11.72	12.15	11.93
Labcorp Holdings Inc.	0.85	8.71	4.75	12.15	12.48	12.31
Monster Beverage Corporation	0.70	8.71	4.75	10.84	11.50	11.17
O'Reilly Automotive Inc.	0.75	8.71	4.75	11.28	11.82	11.55
Quest Diagnostics Inc.	0.70	8.71	4.75	10.84	11.50	11.17
RLI Corporation	0.80	8.71	4.75	11.72	12.15	11.93
Sysco Corporation	0.85	8.71	4.75	12.15	12.48	12.31
W.R. Berkley Corporation	0.85	8.71	4.75	12.15	12.48	12.31
Walmart Inc.	0.75	8.71	4.75	11.28	11.82	11.55
Mean	0.79			11.61 %	12.08 %	11.84 %
Median	0.80			11.72 %	12.15 %	11.93 %
Average of Mean and Median	0.80			11.67 %	12.12 %	11.89 %

Notes:

(1) From note 1 of page 25 of this Schedule.

(2) From note 2 of page 25 of this Schedule.

(3) Average of CAPM and ECAPM cost rates.

UGI Utilities, Inc.
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on February 13, 2026 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	UGI Utilities, Inc.	$ 3,785.261		6	0.88%	
2.	Proxy Group of Six Natural Gas Companies	$ 5,906.520	1.6 x	5	0.65%	0.24%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 53,677.496	$ 4,542,663.305	0.01%
	2	20,547.627	53,647.975	0.27%
	3	10,784.341	20,493.885	0.40%
	4	6,449.090	10,707.825	0.37%
	5	4,237.161	6,442.608	0.65%
	6	2,522.120	4,232.272	0.88%
	7	1,472.350	2,518.431	1.05%
	8	782.513	1,472.329	0.77%
	9	351.125	782.173	1.68%
Smallest	10	3.747	351.051	4.37%

*From 2026 Kroll Cost of Capital Navigator

Notes:

(1) From page 37 of this Schedule.

(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].

(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.

(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.24% in Column [4], Line No. 2 is derived as follows 0.24% = 0.88% - 0.65%.

UGI Utilities, Inc.
Market Capitalization of UGI Utilities, Inc. and the
Proxy Group of Six Natural Gas Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2025 (millions)	[2] Book Value per Share at Fiscal Year End 2025 (1)	[3] Total Common Equity at Fiscal Year End 2025 (millions)	[4] Closing Stock Market Price on March 31, 2026	[5] Market-to-Book Ratio on March 31, 2026 (2)	[6] Market Capitalization on March 31, 2026 (3) (millions)
UGI Utilities, Inc.		NA	NA	1,998.554 (4)	NA		
Based upon Proxy Group of Six Natural Gas Companies						189.40 (5)	$ 3,785.261 (6)
Proxy Group of Six Natural Gas Companies							
Atmos Energy Corporation	NYSE	$ 161.69	$ 83.86	$ 13,558.89	$ 184.72	220.30 %	$ 29,867.99
New Jersey Resources Corporation	NYSE	100.74	23.74	2,391.67	54.92	231.30	5,532.85
NiSource Inc.	NYSE	478.53	19.75	9,450.10	46.66	236.30	22,328.36
Northwest Natural Holding Company	NYSE	41.56	35.49	1,475.08	53.22	150.00	2,212.03
ONE Gas, Inc.	NYSE	62.69	54.87	3,440.12	86.13	157.00	5,399.70
Southwest Gas Holdings, Inc.	NYSE	72.27	54.81	3,961.12	86.90	158.50	6,280.19
Median		$ 86.51	$ 45.15	$ 3,700.62	$ 70.53	189.40 %	$ 5,906.52

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of UGI Utilities, Inc. on March 31, 2026 is assumed to be equal to the market-to-book ratio of Proxy Group of Six Natural Gas Companies on March 31, 2026 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2025 Annual Forms 10K
Bloomberg Professional

UGI Utilities, Inc.
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances

Date of Offering	Transaction (1)	[Column 1] Shares Issued (1)	[Column 2] Average Offering Price per Share (1)	[Column 3] Total Offering Expense per Share (1)	[Column 4] Net Proceeds per Share (2)	[Column 5] Gross Equity Issue before Costs (3)	[Column 6] Total Net Proceeds (4)	[Column 7] Total Flotation Costs (5)	[Column 8] Flotation Cost Percentage (6)
5/25/2021	Equity Unit Offering	5,054,030	$ 100.00	$ 3.000	$ 97.0000	$ 505,403,000	$ 490,240,910	$ 15,162,090	3.00%
3/24/2004	Equity Offering	7,500,000	$ 32.10	$ 1.404	$ 30.6956	$ 240,750,000	$ 230,217,000	$ 10,533,000	4.38%
	Total Public Issuances					$ 746,153,000	$ 720,457,910	$ 25,695,090	3.44%

Flotation Cost Adjustment

	[Column 9] Average Dividend Yield (7)	[Column 10] Average Projected EPS Growth Rate (7)	[Column 11] Adjusted Dividend Yield (8)	[Column 12] Average DCF Cost Rate Unadjusted for Flotation (9)	[Column 13] DCF Cost Rate Adjusted for Flotation (10)	[Column 14] Flotation Cost Adjustment (11)
Proxy Group of Six Natural Gas Companies	3.13 %	7.71 %	3.25 %	10.96 %	11.08 %	0.12 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 1 x Col. 2
(4) Col. 1 x Col. 4
(5) Col. 1 x Col. 3
(6) (Col. 5 - Col. 6) / Col. 5
(7) From page 6 of this Schedule.
(8) Col. 9 * (1 + (0.5 * Col. 10))
(9) Col. 10 + Col. 11
(10) (Col. 11 / (1 - Col. 8)) + Col. 10
(11) Col. 13 - Col. 12

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Comparable Earnings: New Life for an Old Precept

by
Frank J. Hanley
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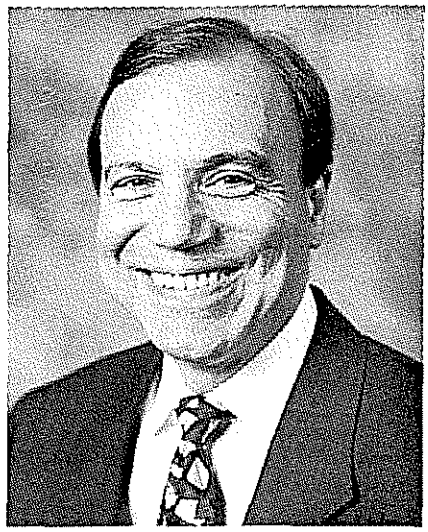
Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.



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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

Comparable Earnings *from page 4*

more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i r_{mt} + e_{it}$$

where:

- r_{it} = tth observation of the ith utility's rate of return
- r_{mt} = tth observation of the market's rate of return
- e_{it} = tth random error term
- a_i = constant least-squares regression coefficient
- b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i) = total risk of ith asset
= var($a_i + b_i r_m + e$)
substituting ($a_i + b_i r_m + e$) for r_i
= var($b_i r_m$) + var (e) since var(a_i) = 0
= b_i^2 var(r_m) + var (e) since var($b_i r_m$) = b_i^2 var(r_m)
= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2 (r_i|r_m)$ = ... = var (e). The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

continued on page 6

Comparable Earnings *from page 5*

pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 (0.1664 = 3.7867/ $\sqrt{2(259)}$ = 3.7867/22.7596, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1]The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2]Ending 1992.
[3]1996-1998/1997-1999.
[4]The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5]Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

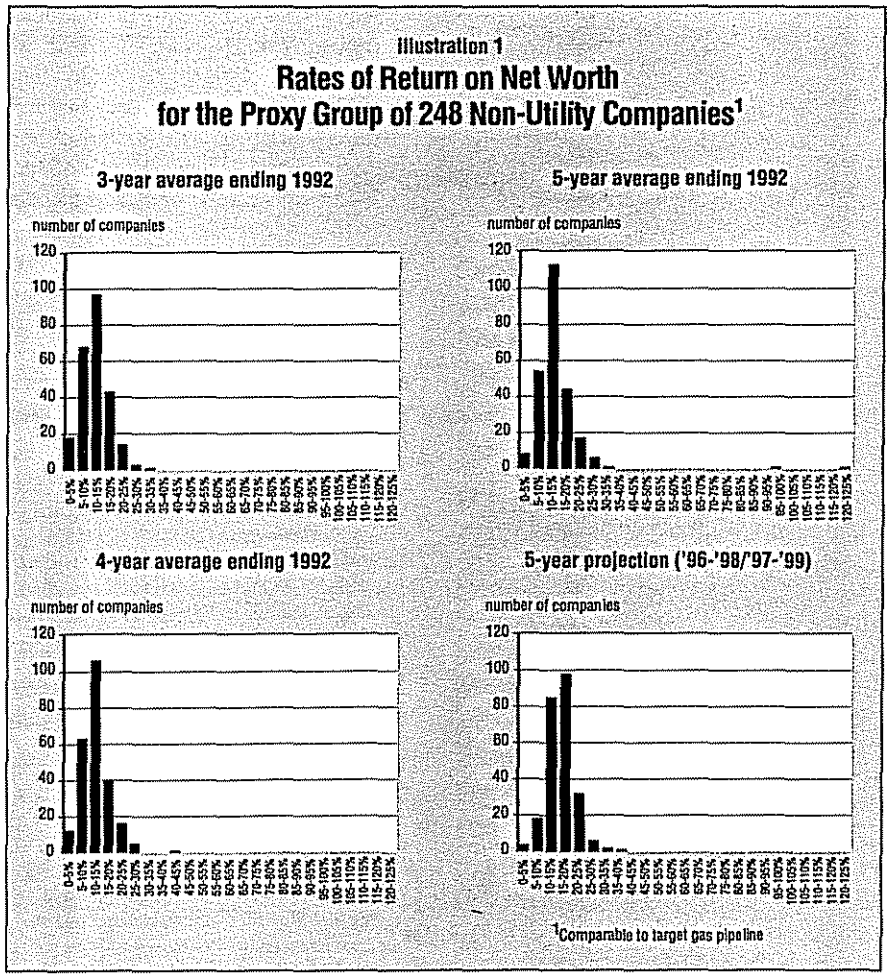
Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

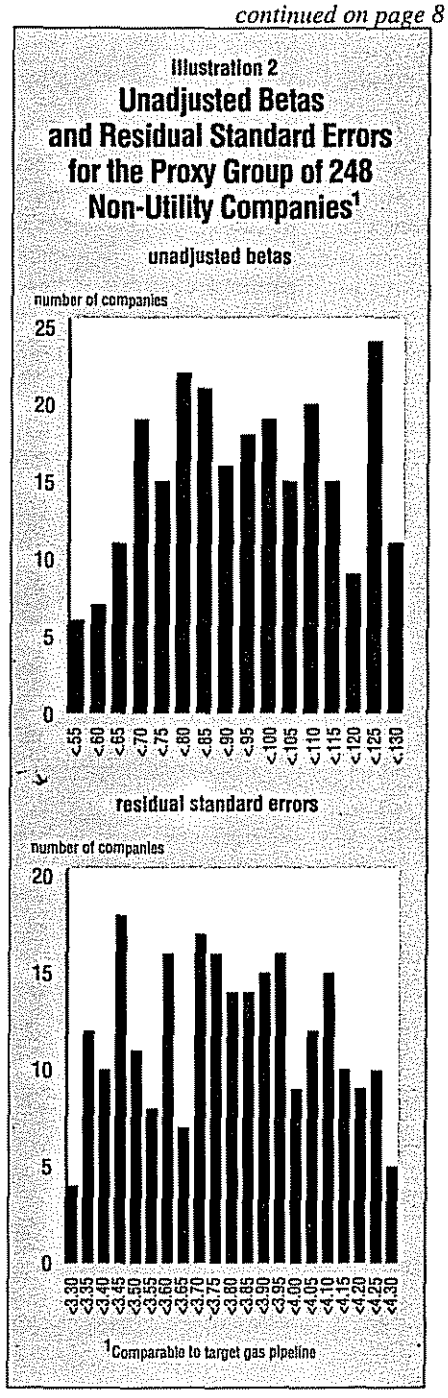
Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

continued on page 8





Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1] *Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co.* 320 U.S. 519 (1944).

[2] Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice. Public Utilities Reports Inc., 1988. p. 379.

[3] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen. Principles of Public Utilities Rates. 2nd edition. Public Utilities Reports Inc. 1988, p. 329.

[4] Jack Clark Francis. Investments: Analysis and Management. 3rd edition. McGraw-Hill Book Co., 1980, p. 363.

[5] Id., p. 548.

[6] Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line.

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

Investments: Analysis and Management

Fifth Edition

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Investments: Analysis and Management

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Beta Measurements The beta coefficient is an *index of systematic risk.* Beta coefficients may be used for ranking the systematic risk of different assets. If the beta is larger than 1, $b > 1.0$, then the asset is more volatile than the market and is called an **aggressive asset.** If the beta is less than 1, $b < 1.0$, the asset is a **defensive asset;** its price fluctuations are less volatile than the market's. Figure 10-1 illustrates the characteristic lines for three different assets that have low, medium, and high levels of beta (or undiversifiable risk).

Figure 10-2 shows that IBM is a stock with an average amount of systematic risk. IBM's beta of 1.02 indicates that its return tends to increase 2 percent more than the return on the market average when the market is rising. When the market falls, IBM's return tends to fall 2 percent more than the market's. The characteristic line for IBM has an above average correlation coefficient of $\rho = .7495$, indicating that the returns on this security follow its particular characteristic line slightly more closely than those of the average stock.

Partitioning Risk Total risk can be measured by the variance of returns, denoted Var(r). This measure of *total risk is partitioned into its systematic and unsystematic components in Equation (10-8).*[7]

$$\begin{aligned} \text{Var}(r_i) &= \text{total risk of } i\text{th asset} \\ &= \text{Var}(a_i + b_i r_{m,t} + e_{i,t}) \\ &\quad \text{by substituting } (a_i + b_i r_{m,t} + e_{i,t}) \text{ for } r_{i,t} \\ &= 0 + \text{Var}(b_i r_{m,t}) + \text{Var}(e_{i,t}) \\ &\quad \text{since Var}(a_i) = 0 \end{aligned} \tag{10-8}$$

$$\begin{aligned} \text{Var}(r_i) &= b_i^2 \text{ Var}(r_m) + \text{Var}(e) \qquad \text{since Var}(b_i r_m) = b_i^2 \text{ Var}(r_m) \\ &= \text{systematic} + \text{unsystematic risk} \end{aligned} \tag{10-8a}$$

$$.01389 = .00780 + .00609 \qquad \text{for IBM}$$

The unsystematic risk measure Var(e) is called in regression language the *residual variance* or, synonymously, the *standard error squared.*

Undiversifiable Proportion The percentage of total risk that is systematic can be measured by the coefficient of determination ρ^2 (that is, the characteristic line's squared correlation coefficient).

[7]In this context, **partition** is a technical statistical term that means to divide the total variance into *mutually exclusive* and *exhaustive* pieces. This partition is only possible if the returns from the market are statistically independent from the residual error terms that occur simultaneously, $\text{Cov}(r_{m,t}, e_{i,t}) = 0$. The mathematics of regression analysis will orthogonalize the residuals and thus ensure that the needed statistical independence exists.

$$\frac{\text{Systematic risk}}{\text{Total risk}} = \frac{b_i^2 \text{ Var}(r_m)}{\text{Var}(r_m)} = \rho^2 \qquad (10\text{-}9)$$

$$\frac{.007802}{.01389} = \frac{(1.021)^2\ (.00749)}{.00749} = .5617 \times 100 = 56.17\% \quad \text{for IBM}$$

Diversifiable Proportion The percentage of unsystematic risk equals $(1.0 - \rho^2)$.

$$\frac{\text{Unsystematic risk}}{\text{Total risk}} = \frac{\text{Var}(e)}{\text{Var}(r_i)} = (1.0 - \rho^2)$$

$$\frac{.00609}{.01389} = (1.0 - .5617) = .438 \times 100 \qquad (10\text{-}10)$$

$$= 43.8\% \text{ unsystematic} \quad \text{for IBM}$$

Studies of the characteristic lines of hundreds of stocks listed on the NYSE indicate that the average correlation coefficient is approximately $\rho = .5$.[8] This means that about $\rho^2 = 25$ percent of the total variability of return in most NYSE securities is explained by movements in the market.

	NYSE average	IBM
Systematic risk: ρ^2	.25	.5617
Unsystematic risk: $(1.0 - \rho^2)$	.75	.4383
Total risk: 100%	1.00	1.0000

As explained above, systematic changes are common to all stocks and are therefore undiversifiable.

A primary use of the characteristic line (or *market model,* or the *single-index model,* as it is also called) is to assess the risk characteristics of one asset.[9] The statistics in Table 10-2, for instance, indicate that IBM's common stock is slightly more risky than the average common stock in terms of total risk and

[8]The average ρ was found to be about .5, as reported in Marshall Blume, "On the Assessment of Risk," *Journal of Finance,* March 1971, p. 4. For similar estimates, see J. C. Francis, "Statistical Analysis of Risk Surrogates for NYSE Stocks," *Journal of Financial and Quantitative Analysis,* Dec. 1979.

[9]Professor Jensen reformulated the characteristic line in a risk-premium form. See M. C. Jensen, "The Performance of Mutual Funds in the Period 1945 through 1964," *Journal of Finance,* May 1968, pp. 389–416. See also M. C. Jensen, "Risk, the Pricing of Capital Assets, and the Evaluation of Investment Portfolios," *Journal of Business,* vol. XLII, 1969. Jensen interprets the alpha intercept term of the characteristic line, as he formulates it, as an investment performance measure. It has been suggested that Jensen's performance measure is biased. See Keith V. Smith and Dennis A. Tito, "Risk-Return Measures of Ex-Post Portfolio Performance," *Journal of Financial and Quantitative Analysis,* Dec. 1969, vol. IV, no. 4, p. 466.

systematic risk.[10] New risk measurements must be made periodically, however, because the risk and return of an asset may change with the passage of time.[11]

10-3 CAPITAL ASSET PRICING MODEL (CAPM)

An old axiom states "there is no such thing as a free lunch." This means that you cannot expect to get something for nothing—a rule that certainly applies to investment returns. Investors who want to earn high average rates of return must take high risks and endure the associated loss of sleep, the possibility of ulcers, and the chance of bankruptcy. The question to which we now turn is: Should investors worry about total risk, undiversifiable risk, diversifiable risk, or all three?

In Chapter 1 it was suggested that *investors should seek investments that have the maximum expected return in their risk class.* Their happiness from investing is presumed to be derived as indicated in the expected utility $E(U)$ function below.

$$E(U) = f[E(r), \sigma]$$

The investment preferences of wealth-seeking risk-averse investors represented by the function above cause them to maximize their expected utility (or, equivalently, happiness) by (1) maximizing their expected return in any given risk class, $\partial E(U)/\partial E(r) > 0$, or, conversely, (2) minimizing their total risk at any given rate of expected return, $\partial E(U)/\partial \sigma < 0$. However, in selecting individual assets, investors will not be particularly concerned with the asset's total risk σ. Figure 9-1 showed that the unsystematic portion of total risk can be easily diversified by holding a portfolio of different securities. But, systematic risk affects all stocks in the market because it is undiversifiable. Portfolio theory therefore suggests that only the undiversifiable (or systematic) risk is worth avoiding.[12]

[10]Statements about the relative degree of total risk are made in the context of a long-run horizon—that is, over at least one *complete business cycle*. Obviously, an accurate short-run forecast which says that some particular company will go bankrupt next quarter makes it more risky than IBM, although IBM may have had more historical variability of return.

[11]Empirical studies documenting the intertemporal instability of betas have been published. Marshall Blume, "Betas and Their Regression Tendencies," *Journal of Finance,* June 1975, pp. 785–795. See also J. C. Francis, "Statistical Analysis of Risk Coefficients for NYSE Stocks," *Journal of Financial and Quantitative Analysis,* Dec. 1979, vol. XIV, no. 5, pp. 981–997. An appendix at the end of this chapter reviews some evidence about shifting betas, standard deviations, and correlations.

[12]Both the systematic and unsystematic portions of total risk must be considered by **undiversified investors.** Entrepreneurs who have their entire net worth invested in one business, for example, can be bankrupted by a piece of bad luck that could be easily averaged away to zero in a diversified portfolio. Poorly diversified investors should not treat diversifiable risk lightly. Only well-diversified investors can afford to ignore diversifiable risk.

UGI Utilities, Inc.
Corrections to Mr. Breuning's
CAPM with Forecasted Returns and Fully Projected Risk-Free Rate

Re	Required return on individual equity security
Rf	Risk-free rate
Rm	Required return on the market as a whole
Be	Beta on individual equity security

Re = Rf+Be(Rm-Rf)

Rf	=	4.74	(1)
Rm	=	11.86	(2)
Be	=	0.78	(3)
Re (CAPM)	=	10.29	%
Re (ECAPM)	=	10.68	%
Re (Average)	=	**10.49**	%

Notes:

(1) For reasons explained in Mr. D'Ascendis' Direct and Rebuttal Testimonies, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. The projection of the risk-free rate is illustrated below:

First Quarter 2026	4.80
Second Quarter 2026	4.80
Third Quarter 2026	4.80
Fourth Quarter 2026	4.80
First Quarter 2027	4.80
Second Quarter 2027	4.80
2027-2031	4.60
2032-2036	4.50
	4.74

Source: Blue Chip Financial Forecasts January 30, 2026 and December 1, 2025.

(2) See page 2 of this Schedule.
(3) From I&E Exhibit No. 2, Schedule 18.

UGI Utilities, Inc.
Corrections to Mr. Breuning's
Forecasted Required Rate of Return on Market as a Whole

	Dividend Yield	+	Growth Rate	=	Expected Market Return
27-Feb-26	2.00%		8.78%		10.78%
20-Feb-26	2.00%		8.78%		10.78%
13-Feb-26	2.00%		8.78%		10.78%
6-Feb-26	2.00%		8.78%		10.78%
30-Jan-26	2.10%		7.79%		9.89%
23-Jan-26	2.10%		7.79%		9.89%
16-Jan-26	2.10%		8.78%		10.88%
9-Jan-26	2.10%		8.78%		10.88%
2-Jan-26	2.10%		8.78%		10.88%
26-Dec-25	2.10%		8.78%		10.88%
19-Dec-25	2.10%		8.78%		10.88%
12-Dec-25	2.20%		8.78%		10.98%
5-Dec-25	2.20%		9.73%		11.93%
28-Nov-25	2.30%		9.73%		12.03%
21-Nov-25	2.20%		9.73%		11.93%
14-Nov-25	2.20%		9.73%		11.93%
7-Nov-25	2.10%		8.78%		10.88%
31-Oct-25	2.10%		8.78%		10.88%
24-Oct-25	2.20%		8.78%		10.98%
17-Oct-25	2.10%		8.78%		10.88%
10-Oct-25	2.10%		8.78%		10.88%
3-Oct-25	2.10%		7.79%		9.89%
26-Sep-25	2.10%		8.78%		10.88%
19-Sep-25	2.10%		7.79%		9.89%
12-Sep-25	2.10%		8.78%		10.88%
5-Sep-25	2.10%		8.78%		10.88%
29-Aug-25	2.20%		8.78%		10.98%
22-Aug-25	2.20%		9.73%		11.93%
15-Aug-25	2.20%		9.73%		11.93%
8-Aug-25	2.10%		8.78%		10.88%
1-Aug-25	2.10%		8.78%		10.88%
25-Jul-25	2.10%		8.78%		10.88%
18-Jul-25	2.10%		8.78%		10.88%
11-Jul-25	2.20%		9.73%		11.93%
4-Jul-25	2.20%		9.73%		11.93%
27-Jun-25	2.20%		9.73%		11.93%
20-Jun-25	2.20%		9.73%		11.93%
13-Jun-25	2.30%		10.67%		12.97%
6-Jun-25	2.30%		10.67%		12.97%
30-May-25	2.20%		9.73%		11.93%
23-May-25	2.30%		10.67%		12.97%
16-May-25	2.30%		11.58%		13.88%
9-May-25	2.40%		12.47%		14.87%
2-May-25	2.40%		14.19%		16.59%
25-Apr-25	2.50%		13.34%		15.84%
18-Apr-25	2.50%		15.02%		17.52%
11-Apr-25	2.20%		12.47%		14.67%
4-Apr-25	2.20%		11.58%		13.78%
28-Mar-25	2.20%		11.58%		13.78%
21-Mar-25	2.20%		11.58%		13.78%
14-Mar-25	2.20%		11.58%		13.78%
7-Mar-25	2.10%		10.67%		12.77%

Spot Value Line Estimate	10.78%
52-Week Average Value Line Estimate	11.95%
Average Value Line Estimate	11.36%
S&P 500 Historical Return	12.35%
Average Expected Market Return	11.86%

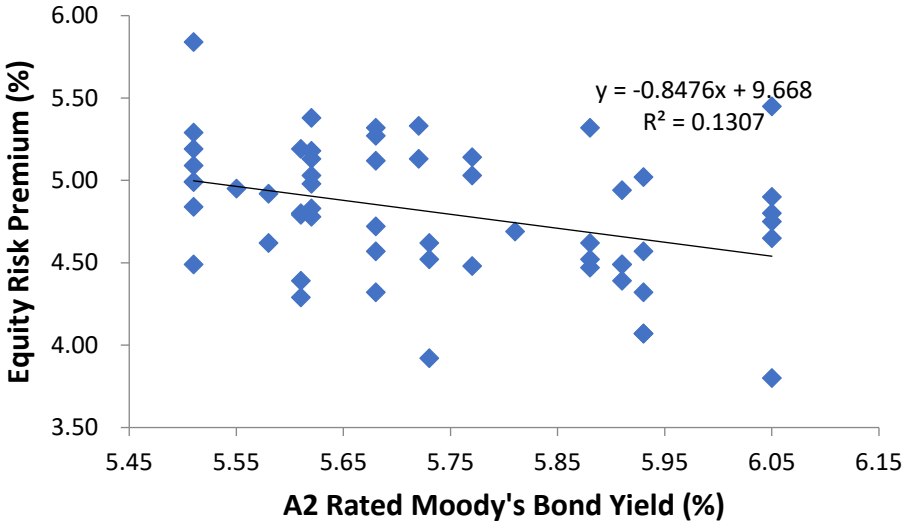
Sources:
52-week average Value Line Summary & Index, I&E Exhibit No. 2,

UGI Utilities, Inc.
Comparison of Market Return Measures

	[1]	[2]	[3]	[4]	[5]
	Actual Market Return (1)	LT average Market Return (2)	Kroll (3)	Damodaran (4)	Fernandez Survey (5)
2009	26.46%	11.67%	10.50%	8.64%	10.75%
2010	15.06%	11.85%	10.08%	8.20%	10.25%
2011	2.11%	11.88%	9.63%	8.49%	9.32%
2012	16.00%	11.77%	10.00%	7.89%	7.96%
2013	32.39%	11.82%	9.50%	7.54%	8.10%
2014	13.69%	12.05%	9.00%	8.00%	8.81%
2015	1.38%	12.07%	9.00%	7.95%	7.90%
2016	11.96%	11.95%	9.50%	8.39%	7.60%
2017	21.83%	11.95%	9.00%	8.14%	8.20%
2018	-4.38%	12.06%	8.50%	7.49%	8.20%
2019	31.49%	11.88%	9.00%	8.64%	8.30%
2020	18.40%	12.09%	8.50%	7.12%	7.50%
2021	28.71%	12.16%	8.00%	5.65%	7.30%
2022	-18.11%	12.33%	8.00%	5.75%	8.30%
2023	26.61%	12.02%	10.14%	9.82%	9.50%
2024	25.62%	12.16%	10.03%	8.48%	9.60%
2025	18.06%	12.30%	10.06%	8.91%	9.60%
Sum	267.28%	204.01%	158.44%	135.10%	147.19%
Forecast Bias (6)		**76.33%**	**59.28%**	**50.55%**	**55.07%**

Notes:
(1) Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator; Bloomberg Professional Services.
(2) Rolling historic long-term average of data in Column 1 since 1926.
(3) Source: Kroll Recommended ERP + Corresponding Risk-Free Rate.
(4) Source: Damodaran: Implied Equity Risk Premiums - United States plus corresponding risk-free rate.
(5) Source: Pablo Fernandez, IESE Business School MRP and RFR Survey.
(6) Sum of forecasts divided by sum of actual observations.

UGI Utilities, Inc.
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium	Indicated ROE
9.6680 %	-0.8476	5.68 %	4.85 %	10.53 %

Notes:

(1) From line 3 of page 13 of Schedule DWD-1R.

Source of Information: I&E Exhibit No. 2, Schedule 6,
Bloomberg Professional Services

UGI Utilities, Inc.
Standard Deviation of DCF Results for
Mr. Breuning's Natural Gas Proxy Group

Company Name	Adjusted Dividend Yield	Average Growth Rate	Expected Market Cost Rate of Equity
Atmos Energy Corporation	2.47 %	7.79 %	10.26 %
Chesapeake Utilities Corp.	2.27	8.08	10.35
New Jersey Resources Corporation	4.11	6.78	10.89
NiSource Inc.	2.93	8.07	11.00
Northwest Natural Holding Company	4.17	5.75	9.92
ONE Gas, Inc.	3.38	7.07	10.45
Standard Deviation			0.37 %

Source of Information: Mr. Breuning's I&E Exhibit No. 2, Schedule 13.

UGI Utilities, Inc.
Mr. Garrett's Replicated Implied ERP Calculation

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%
2021	40,356	1,739	511	882	4.31%	1.27%	2.18%	3.45%
2022	32,133	1,656	565	923	5.15%	1.76%	2.87%	4.63%
2023	36,870	1,790	588	795	4.85%	1.60%	2.16%	3.75%
2024	49,805	1,967	630	943	3.95%	1.26%	1.89%	3.16%

Cash Yield	4.36%	[9]
Growth Rate	6.95%	[10]
Risk-free Rate	4.82%	[11]
Current Index Value	6,704	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	312	334	357	382	409
Expected Terminal Value					8555
Present Value	285	277	270	263	5610
Intrinsic Index Value	6704	[18]			
Required Return on Market	9.83%	[19]			
Implied Equity Risk Premium	**5.0%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500 (additional info tab) (all dollar figures are in $ billions)
[1] Market value of S&P 500
[5] = [2] / [1]
[6] = [3] / [1]
[7] = [4] / [1]
[8] = [6] + [7]
[9] = Average of [8]
[10] = Compund annual growth rate of [2] = (end value / beginning value)$^{1/10}$-1
[11] Risk-free rate from DJG risk-free rate exhibit
[12] 30-day average of closing index prices from DJG stock price exhibit
[13-16] Expected dividends = [9]*[12]*(1+[10])^{n} ; Present value = expected dividend / (1+[11]+[19])^{n}
[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^{n}
[18] = Sum([13-17]) present values.
[19] = [20] + [11]
[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

UGI Utilities, Inc.
Mr. Garrett's Corrected Implied ERP Calculation

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%
2021	40,356	1,739	511	882	4.31%	1.27%	2.18%	3.45%
2022	32,133	1,656	565	923	5.15%	1.76%	2.87%	4.63%
2023	36,870	1,790	588	795	4.85%	1.60%	2.16%	3.75%
2024	49,805	1,967	630	943	3.95%	1.26%	1.89%	3.16%

ARITHMETIC AVERAGE

Year	Market Value	Operating Earnings	Dividends	Buybacks
2014				
2015	-1.89%	-11.83%	9.10%	3.41%
2016	7.65%	3.89%	3.90%	-6.25%
2017	18.44%	15.89%	5.68%	-3.17%
2018	-7.86%	20.23%	8.70%	55.26%
2019	27.26%	1.79%	6.39%	-9.63%
2020	18.31%	-21.89%	-1.05%	-28.69%
2021	27.47%	70.61%	6.42%	69.66%
2022	-20.38%	-4.78%	10.43%	4.65%
2023	14.74%	8.11%	4.19%	-13.82%
2024	35.08%	9.87%	7.04%	18.54%
	11.88%	9.19%	6.08%	9.00%

Cash Yield	4.36%	[9]
Growth Rate	9.04%	[10]
Risk-free Rate	4.82%	[11]
Current Index Value	6,704	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	319	347	379	413	450
Expected Terminal Value					8633
Present Value	289	286	282	279	5568
Intrinsic Index Value	6704	[18]			
% Terminal Value	78.94%				
Required Return on Market	10.28%	[19]			
Implied Equity Risk Premium	**5.5%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500 (additional info tab) (all dollar figures are in $ billions)
[1] Market value of S&P 500
[5] = [2] / [1]
[6] = [3] / [1]
[7] = [4] / [1]
[8] = [6] + [7]
[9] = Average of [8]
[10] = Average of arithmetic mean of Market Value, Operating Earnings, Dividends and Buybacks.
[11] Risk-free rate from DJG risk-free rate exhibit
[12] 30-day average of closing index prices from DJG stock price exhibit
[13-16] Expected dividends = [9]*[12]*(1+[10])^n ; Present value = expected dividend / (1+[11]+[19])^n
[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^n
[18] = Sum([13-17]) present values.
[19] = [20] + [11]
[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

UGI Utilities, Inc.
Gross Domestic Product by Industry
from 1947 - 2025

Industry	1947	2025	CAGR
Agriculture, forestry, fishing, and hunting	19.9	272.0	3.41%
Mining	5.8	384.3	5.52%
Utilities	3.5	471.2	**6.49%**
Construction	8.9	1,341.3	**6.64%**
Manufacturing	63.4	2,896.5	5.02%
Wholesale trade	15.6	1,905.4	6.35%
Retail trade	23.2	1,921.8	5.83%
Transportation and warehousing	14.1	1,023.9	5.65%
Information	7.7	1,695.0	**7.16%**
Finance, insurance, real estate, rental, and leasing	25.8	6,680.4	**7.38%**
Professional and business services	8.2	4,023.4	**8.27%**
Educational services, health care, and social assistance	4.6	2,718.2	**8.53%**
Arts, entertainment, recreation, accommodation, and food services	8.0	1,332.3	**6.78%**
Other services, except government	7.5	649.4	5.89%
Government	33.5	3,447.0	6.12%
Total Gross domestic product	249.7	30,762.1	6.37%

Source: Bureau of Economic Analysis

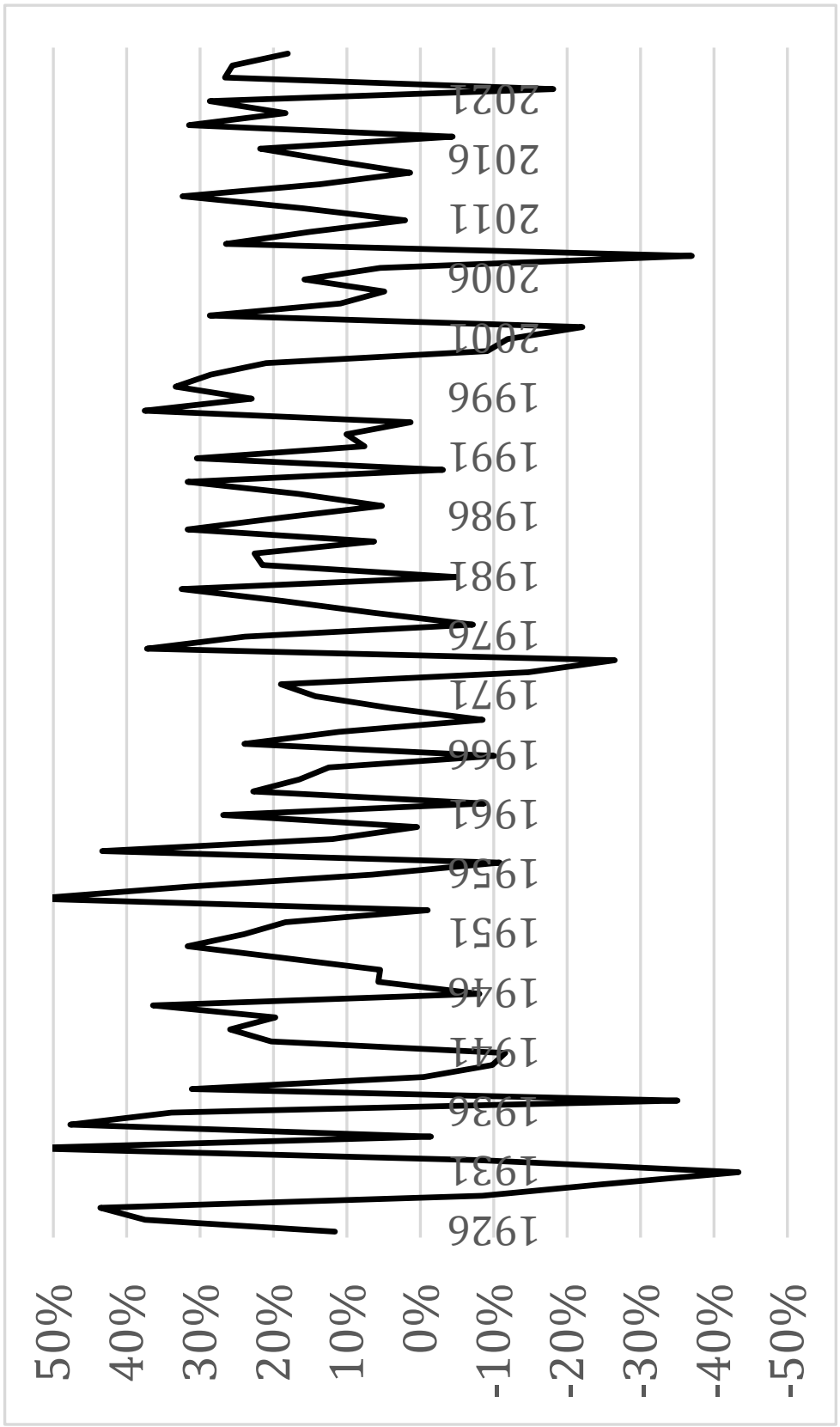
Industry	Gross Domestic Product	1947-2025 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	272.0	3.41%	1	260	2.E+06	
Mining	384.3	5.52%	1	260	5.E+08	
Utilities	471.2	6.49%	1	260	6.E+09	
Construction	1,341.3	6.64%	1	260	2.E+10	
Manufacturing	2,896.5	5.02%	1	260	1.E+09	
Wholesale trade	1,905.4	6.35%	1	260	2.E+10	
Retail trade	1,921.8	5.83%	1	260	5.E+09	
Transportation and warehousing	1,023.9	5.65%	1	260	2.E+09	
Information	1,695.0	7.16%	1	260	1.E+11	
Finance, insurance, real estate, rental, and leasing	6,680.4	7.38%	1	260	7.E+11	
Professional and business services	4,023.4	8.27%	1	260	4.E+12	
Educational services, health care, and social assistance	2,718.2	8.53%	1	260	5.E+12	50.00%
Arts, entertainment, recreation, accommodation, and food services	1,332.3	6.78%	1	260	3.E+10	
Other services, except government	649.4	5.89%	1	260	2.E+09	
Government	3,447.0	6.12%	1	260	2.E+10	
Total Gross domestic product	30,762.1				9.E+12	

Industry	Gross Domestic Product	1947-2025 CAGR	Beginning Year	Ending Year	Gross Domestic Product In Ending Year	% of Total
Agriculture, forestry, fishing, and hunting	272.0	3.41%	1	5,939	8.E+88	
Mining	384.3	5.52%	1	5,939	2.E+141	
Utilities	471.2	6.49%	1	5,939	6.E+164	
Construction	1,341.3	6.64%	1	5,939	9.E+168	
Manufacturing	2,896.5	5.02%	1	5,939	7.E+129	
Wholesale trade	1,905.4	6.35%	1	5,939	1.E+162	
Retail trade	1,921.8	5.83%	1	5,939	2.E+149	
Transportation and warehousing	1,023.9	5.65%	1	5,939	5.E+144	
Information	1,695.0	7.16%	1	5,939	4.E+181	
Finance, insurance, real estate, rental, and leasing	6,680.4	7.38%	1	5,939	4.E+187	
Professional and business services	4,023.4	8.27%	1	5,939	3.E+208	
Educational services, health care, and social assistance	2,718.2	8.53%	1	5,939	3.E+214	100.00%
Arts, entertainment, recreation, accommodation, and food services	1,332.3	6.78%	1	5,939	2.E+172	
Other services, except government	649.4	5.89%	1	5,939	2.E+150	
Government	3,447.0	6.12%	1	5,939	6.E+156	
Total Gross domestic product	30,762.1				3.E+214	

Source: Bureau of Economic Analysis

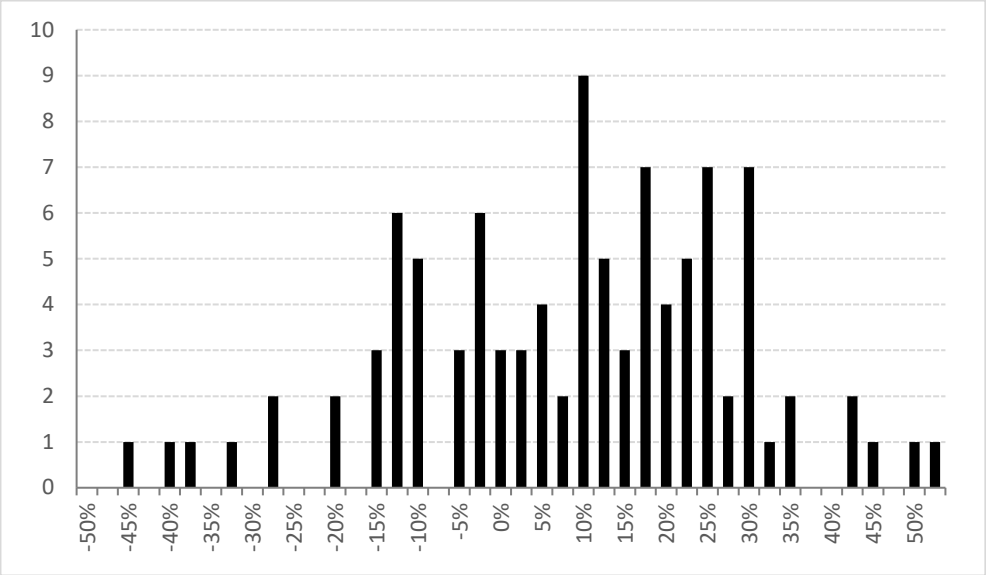
UGI Utilities, Inc.

Large Company Stocks Total Returns



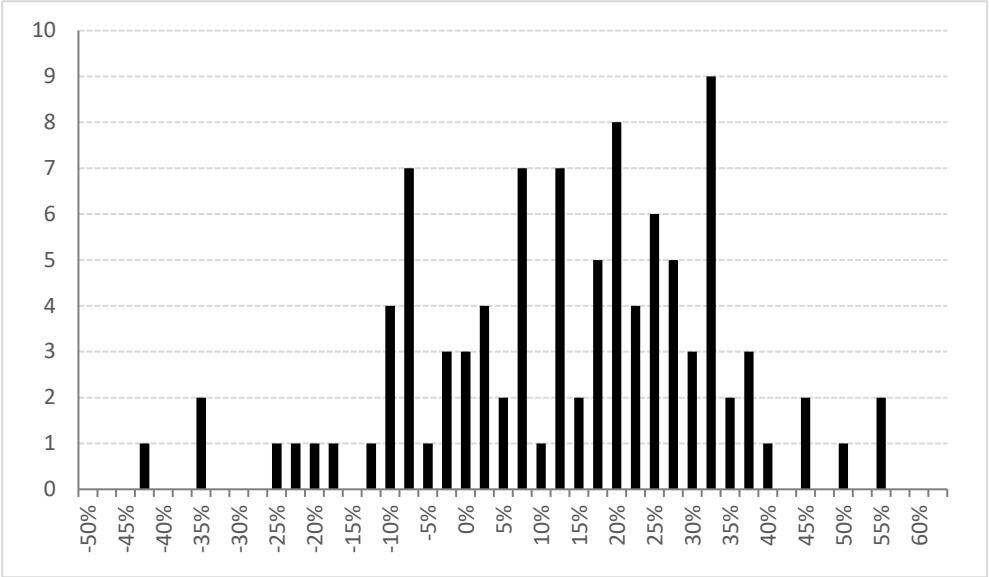
UGI Utilities, Inc.

Frequency Distribution of Market Returns and Market Risk Premiums



Average MRP from Direct	Rank
8.63%	48.70%

Average MRP from Rebuttal	Rank
8.71%	48.80%



Average Return from Direct	Rank
13.16%	47.10%

Average Return from Rebuttal	Rank
13.46%	47.30%

UGI Utilities, Inc.
Summary of Decoupling and Capital Investment Rate Mechanisms for the
Utility Proxy Group

Company	Utility Type	Parent	State	Decoupling [1]	Capital Investment [2]	Forward Test Year Allowed in Jurisdiction [3]
Atmos Energy Corporation						
Atmos Colorado	Gas	ATO	Colorado		✓	
Atmos Kansas	Gas	ATO	Kansas	✓	✓	
Atmos Kentucky	Gas	ATO	Kentucky	✓	✓	✓
Atmos Louisiana	Gas	ATO	Louisiana	✓	✓	✓
Atmos Mississippi	Gas	ATO	Mississippi	✓	✓	K
Atmos Tennessee	Gas	ATO	Tennessee	✓	✓	✓
Atmos Texas	Gas	ATO	Texas	✓	✓	K
Atmos Virginia	Gas	ATO	Virginia	✓	✓	✓
New Jersey Resources Corporation						
New Jersey Natural Gas Company	Gas	NJR	New Jersey	✓	✓	K
NiSource Inc.						
Northern Indiana Public Service Company, LLC	Gas	NI	Indiana	✓	✓	K
Columbia Gas of Kentucky, Inc.	Gas	NI	Kentucky	✓	✓	✓
Columbia Gas of Maryland, Inc.	Gas	NI	Maryland	✓	✓	✓
Columbia Gas of Ohio, Inc.	Gas	NI	Ohio	✓	✓	✓
Columbia Gas of Pennsylvania, Inc.	Gas	NI	Pennsylvania	✓	✓	✓
Columbia Gas of Virginia, Inc.	Gas	NI	Virginia	✓	✓	✓
Northwest Natural Holding Company						
Northwest Natural Gas Company	Gas	NWN	Oregon	✓		✓
Northwest Natural Gas Company	Gas	NWN	Washington			K
ONE Gas, Inc.						
Kansas Gas Service Company, Inc.	Gas	OGS	Kansas	✓	✓	
Oklahoma Natural Gas Company	Gas	OGS	Oklahoma	✓		K
Texas Gas Service Company, Inc.	Gas	OGS	Texas	✓	✓	K
Southwest Gas Holdings, Inc.						
Southwest Gas Corporation	Gas	SWX	Arizona	✓	✓	K
Southwest Gas Corporation	Gas	SWX	California		✓	✓
Southwest Gas Corporation	Gas	SWX	Nevada	✓		K

Notes:
Note: A mechanism may cover one or more cost categories; therefore, designations may not indicate separate
[1] Full or partial decoupling (such as Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs). All full or partial decoupling mechanisms include weather normalization adjustments.
[2] Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.
[3] K = Known and Measurable. Partially forecasted test years are included.
Sources: Company SEC Form 10-Ks; Operating company tariffs; Company Investor Presentations.

UGI Utilities, Inc.
Mr. Cicero Corrected Market Returns

	Inflation-Adjusted Geometric Return (1)	Nominal Geometric Mean Return (2)	Standard Deviation of Equity Returns (3)	Arithmetic Mean Return (4)
DJIA 50 Year	7.52%	11.37%	16.18%	12.67%
DJIA 100 Year	6.90%	10.04%	19.60%	11.96%
S&P 500 50 Year	7.75%	11.61%	16.18%	12.92%
S&P 500 100 Year	7.30%	10.46%	19.60%	12.38%

Notes:
(1) Source: Mr. Cicero Direct Testimony, Page 44, Footnote 93.
(2) The reported inflation-adjusted returns were converted to nominal returns using Mr. Cicero's provided calculators. 50 year returns were calculated from March 1976 - March 2026. 100 Year returns were calculated from March 1926 to March 2026.
DJIA: https://dqydj.com/dow-jones-return-calculator/
S&P 500: https://dqydj.com/sp-500-return-calculator/
(3) Source: 2026 Kroll Cost of Capital Navigator
(4) Calculated by converting the historical return on the market from a geometric mean to an arithmetic mean as shown below:

$$R_A = R_G + \frac{\sigma^2}{2}$$

Where:
R_A = Arithmetic Mean
R_G = Geometric Mean
σ = Standard Deviation of Equity Returns

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 10-R

Rebuttal Testimony of
Sherry A. Epler

Topics Addressed:	**Test Year Sales and Revenues**
	Rate NNS
	Tariff Changes

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 10, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to a portion of the direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E"), I&E Statement No. 4, the direct testimony of Ethan H. Cline. I also respond to a portion of the direct testimony submitted by the Retail Energy Supply Association ("RESA"), RESA Statement No. 1, the direct testimony of Christopher Reyes. Finally, I respond to a portion of the direct testimony submitted by CAUSE-PA, CAUSE-PA Statement No. 1, the direct testimony of Patrick Cicero.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibit SAE-1R.

II. TEST YEAR SALES AND REVENUES

Q. I&E Witness Cline disagrees with the Company's claimed present rate revenue for the fully projected future test year ("FPFTY"). Please summarize his overall recommended adjustments.

A. Witness Cline believes the Company's present rate revenue in the FPFTY has been understated and recommends an adjustment concerning the Rate R/RT heating customer usage decline reflected in the FPFTY, which, according to him, was projected beyond the end of the FPFTY. I&E St. No. 4, at pp. 8-9. He recommends an increase to the average use per R/RT customer of 0.12 Mcf per customer per year as a result. I&E St. No. 4, at p. 12. In total, this would increase present rate Rate R/RT sales by 73,358 Mcf and result in an increase to distribution present rate revenues of $464,481. I&E St. No. 4, at p. 13. Witness Cline also states that there would be a corresponding increase to purchased gas revenue, but notes he has not included that as there would also be an adjustment to purchased gas expense (making that purchased gas revenue adjustment revenue neutral as related to the claimed revenue requirement in this case). I&E St. No. 4, at pp. 13-14.

Q. Is the Company accepting Witness Cline's adjustment at this time?

A. Although the Company does not agree with Witness Cline's basis for his adjustment, and UGI Gas reserves the right to propose similar use per customer determinations in the future, the Company is accepting this adjustment.

Q. Have you prepared a calculation of the detailed impact this adjustment has related to the revenues presented in UGI Gas Exhibit E – Proof of Revenue, specifically as between all distribution revenue, or margin items, and all expense items, or non-margin items?

A. Yes, UGI Gas Exhibit SAE-1R details the calculation breakout of revenue items between: (1) those that are distribution revenue, or margin-related, impacting the revenue requirement claim in this case ($483,884 in total as shown on Line 22); and (2) those that are related to Purchased Gas Cost ("PGC") and other surcharge costs not impacting revenue requirement ($553,552 in total as shown on Line 23). Notably, this detailed exhibit includes the specific $464,481 amount calculated by Witness Cline (Line 12) as well as all other line item revenue impacts related to other riders and charges.

III. RATE NNS

Q. Please explain the position of RESA Witness Reyes as related to the charge for Rate NNS.

A. In my direct testimony, I had provided an updated derivation of Rate NNS costs using the Company's historic methodology associated with the rate development for Rate NNS, as shown in detail in UGI Gas Exhibit SAE-8. However, this update resulted in a lower rate of $0.17/Mcfd than the current Rate NNS rate of $0.22/Mcfd, and my testimony recommended retaining the current rate for Rate NNS. Witness Reyes proposes that UGI "utilize standard cost causation principals and set the NNS rate based on the actual cost to provide the service." RESA St. No. 1, at p. 9.

Q. Do you agree with Witness Reyes?

A. Although I do generally agree with the position that rates should be cost based, I disagree with the idea that the Company's proposed Rate NNS does not adequately reflect the cost of the service. Witness Reyes's testimony does not appear to recognize that the Company has faced opposition to the cost-based methodology it has presented historically. Notably, OCA witnesses have proposed their own version of an alleged cost-based methodology for NNS, which results in significantly higher cost than the $0.22/Mcfd rate the Company is proposing in this proceeding. For example, in the UGI Gas rate case last year, OCA Witness Geiger supported an NNS rate of $2.0340/Mcfd. OCA St. No. 3, at p. 39 at Docket R-2024-3052716. Witness Reyes's testimony claiming that UGI Gas proposes to maintain a high NNS rate does not recognize the significant and material increase that could result to Rate NNS above the current rate if certain historic alternate, but also allegedly cost-based, proposals made by opposing parties were adopted. Further, his argument that UGI Gas will use the proceeds to offset gas costs for default service customers is irrelevant to the question of whether the proposed rate is just and reasonable, as NNS revenue offsets an appropriate portion of purchase gas costs based on such just and reasonable determination; lowering default service customer costs no matter what level the rate is set at. UGI Gas's proposal in this case is simply a meaningful "cost-based" compromise reflecting, as a starting point, the position that has been agreed to historically by interested parties.

Q. What is your recommendation as related to Rate NNS?

A. Given the reasons stated above, I do not agree with Witness Reyes that the current rate should be lowered at this time. The proposed retention of the current Rate NNS rate is a

balance of opposing methodologies for a cost basis related to Rate NNS; one which is also intended to avoid unnecessary related litigation time, effort and expense. The current rate appropriately credits overall gas costs for the use of and costs related to PGC assets.

IV. TARIFF CHANGES

Q. CAUSE-PA Witness Cicero recommends that as part of its compliance tariff filing, "UGI should eliminate all references to expired sections of the Public Utility Code and should correct all outdated references to state agency names," such as Department of Public Welfare as opposed to Department of Human Services. CAUSE-PA St. No. 1, at p. 93. Does the Company agree with this recommendation?

A. Yes.

V. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit SAE-1R

UGI Utilities, Inc. - Gas Division
Residential Service - Rate Schedules R & RT
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Exhibit E
S. A. Epler
Page 2 of 7

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charges	7,611,024		$ 16.25	$ 123,679,140	$ 23.00	$ 175,053,552	$ 51,374,412	
Distribution Charges		50,491,037	$ 6.3317	$ 319,694,099	$ 6.8383	$ 345,272,858	$ 25,578,759	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 79,456	0.00%	$ -	$ (79,456)	
Purchased Gas Costs (PGC) - Rider B		44,265,497	$ 6.7486	$ 298,730,133	$ 6.7486	$ 298,730,133	$ -	
Merchant Function Charge (MFC) - Rider D		44,265,497	2.56%	$ 7,647,491	2.37%	$ 7,079,904	$ (567,587)	
Gas Procurement Charge (GPC) - Rider E		44,265,497	$ 0.0660	$ 2,921,523	$ 0.0660	$ 2,921,523	$ -	
Universal Service Program (USP) - Rider F		47,870,552	$ 0.6363	$ 30,460,032	$ 0.6363	$ 30,460,032	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider G		50,491,037	$ 0.1940	$ 9,795,261	$ 0.1940	$ 9,795,261	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 1,630,852	0.00%	$ -	$ (1,630,852)	
Total - Rates R/RT	**7,611,024**	**50,491,037**		**$ 794,637,988**		**$ 869,313,264**	**$ 74,675,276**	**9.4%**

I&E Adjustment to remove post-FPFTY UPC

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue Adjustment (4)	Rate R/RT Current Usage Current Revenue (5)	Rate R/RT Adjusted Usage Current Revenue (6)
Customer Charges-No Adjustment					$ 123,679,140	$ 123,679,140
Distribution Charges		73,358	$ 6.3317	$ 464,482	$ 319,694,099	$ 320,158,581
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 104	$ 79,456	$ 79,560
Purchased Gas Costs (PGC) - Rider B		73,358	$ 6.7486	$ 495,065	$ 298,730,133	$ 299,225,198
Merchant Function Charge (MFC) - Rider D		73,358	2.56%	$ 12,674	$ 7,647,491	$ 7,660,165
Gas Procurement Charge (GPC) - Rider E		73,358	$ 0.0660	$ 4,842	$ 2,921,523	$ 2,926,364
Universal Service Program (USP) - Rider F		69,551	$ 0.6363	$ 44,255	$ 30,460,032	$ 30,504,288
Energy Efficiency & Conservation Rider (EEC) - Rider G		73,358	$ 0.1940	$ 14,231	$ 9,795,261	$ 9,809,493
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 1,784	$ 1,630,852	$ 1,632,636
Total - Rates R/RT	**-**	**73,358**		**$ 1,037,436**	**$ 794,637,988**	**$ 795,675,424**

Revenue	$ 1,037,436
Margin	$ 483,884
COG/PGC Flowback	$ 553,552

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 11-R

Rebuttal Testimony of
John D. Taylor, CEO
Atrium Economics, LLC

Topics Addressed:	**Cost of Service**
	Revenue Targets by Class
	Customer Charges
	Weather Normalization Adjustment

Dated: May 13, 2026

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as Chief Executive Officer ("CEO"). My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 11, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by other parties. The areas I address are outlined below, with reference to the corresponding direct testimony of the other parties:

Proposed Revenue Targets by Class

- Office of Consumer Advocate ("OCA") Statement 1 – Direct testimony of Michael Deupree ("OCA Witness Deupree" or "Witness Deupree");
- Office of Small Business Advocate ("OSBA") Statement No. 1 – Direct testimony of Mark D. Ewen ("OSBA Witness Ewen" or "Witness Ewen"); and
- Coalition For Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1 – Direct testimony of Patrick M. Cicero ("CAUSE-PA Witness Cicero" or "Witness Cicero").

Allocated Class Cost of Service Study

- OCA Witness Deupree; and
- OSBA Witness Ewen.

Customer Charges

- OCA Witness Deupree;
- CAUSE-PA Witness Cicero;
- OCA Statement 6 – Direct testimony of Roger Colton ("OCA Witness Colton" or Witness Colton); and
- Bureau of Investigation and Enforcement ("I&E") Statement No. 3 – Direct testimony of Ethan H. Cline ("I&E Witness Cline" or "Witness Cline").

Weather Normalization Adjustment

- OCA Witness Deupree;
- CAUSE-PA Witness Cicero;
- OSBA Witness Ewen; and
- I&E Witness Cline.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No, I am not.

Q. Please summarize your primary conclusions in this proceeding.

A. UGI Gas requests that the Pennsylvania Public Utility Commission ("Commission" or "PUC") approve the Company's filed proposals because they reasonably reflect cost causation principles while appropriately considering customer impacts. Specifically:

i. The Company's revenue allocation approach appropriately uses the results of the Company's fully Allocated Cost of Service Study ("ACOSS") as the primary guide while applying gradualism to moderate customer bill impacts and move class revenues toward cost-based parity in a measured manner.

ii. The Company's proposed increase in the Residential monthly customer charge from $16.25 to $23.00 is a measured step toward more cost-reflective recovery of

fixed customer-related costs and improves bill stability, while preserving substantial volumetric pricing signals.

iii. Extending the existing Weather Normalization Adjustment ("WNA") mechanism pilot will help reduce weather-driven volatility in both customer bills and the Company's recovery of Commission-authorized distribution revenues, and the use of a 10-year normal Heating Degree Day ("HDD") average reasonably reflects more recent weather patterns.

iv. The proposed modifications to the WNA presented by intervening parties should be denied as they reduce the effectiveness of the WNA and provide no value to customers.

II. PROPOSED REVENUE TARGETS BY CLASS

Q. Please summarize the Company's proposed revenue apportionment in this proceeding.

A. Using the ACOSS as the principal guide, the Company proposes to allocate the requested base distribution revenue increase in a manner that moves customer classes closer to their indicated cost of service and reduces existing interclass subsidies, while also recognizing the principle of gradualism. Accordingly, the Company did not propose an immediate full movement to parity but instead proposed a moderated revenue apportionment that improves class revenue-to-cost relationships over time without imposing abrupt rate impacts in a single case.

Q. Please summarize the principal positions advanced by the parties regarding revenue apportionment.

A. Although both the OCA and OSBA propose alternative revenue apportionment approaches, neither party rejects the general principle that class revenues should continue to move closer to cost responsibility while considering gradualism and customer impact. Rather, their recommendations primarily concern the degree of movement among classes. Specifically, OCA proposes a revenue apportionment based on its alternative ACOSS results, with a cap limiting any class increase to no more than 1.15 times the system average increase and with elimination of the modest proposed decreases to certain high load factor classes.[1] Similarly, OSBA recommends removal of the relatively small proposed revenue decreases to Rate XD and Rate IS and reallocation of those amounts primarily to Rate DS.[2] Thus, while these parties recommend certain modifications, both of them continue to recognize the appropriateness of using the ACOSS as the principal guidepost in assigning the overall revenue increase among customer classes.

CAUSE-PA Witness Cicero states that he is not taking a specific position on the allocation of the overall revenue requirement across rate classes and does not opine whether UGI Gas's proposed cost allocation is methodologically sound. Nevertheless, he argues that cost of service should be viewed only as a guide and not the sole determinant of revenue apportionment, asserting that the Commission should consider broader affordability and customer impact concerns. On that basis, he criticizes the Company's proposal because certain customers receive a rate decrease (Rate XD and Rate IS) while

[1] OCA St. 1, at pp. 57-58.
[2] OSBA St. No. 1, at pp. 12-13.

other classes receive increases, and contends that if an increase is approved, all customer classes should share in the associated burden, subject to cost causation and gradualism.[3]

Q. Have you compared the revenue apportionment outcomes proposed by various parties?

A. Yes. As presented in Table 1 below, I compared the percentage of total increase assigned to each class across the Company and other parties' proposals.

Table 1 - Comparison of Revenue Increase by Class Among Parties[4]

Rate Classes	UGI Gas	OCA	OSBA	Average OCA & OSBA
Rate R	75.15%	69.95%	75.15%	**72.55%**
Rate N	23.53%	22.07%	23.53%	**22.80%**
Rate DS	0.71%	0.00%	0.57%	**0.29%**
Rate LFD	0.74%	7.98%	0.74%	**4.36%**
Rate XD Firm	-0.06%	0.00%	0.00%	**0.00%**
Rate IS	-0.07%	0.00%	0.00%	**0.00%**
Total	100.00%	100.00%	100.00%	**100.00%**

Q. What explains the differences in revenue apportionment among the parties?

A. The differences in revenue apportionment among the parties are driven by two primary factors. First, OCA relies on its own cost-of-service study results, which reflect differing assumptions and methodologies. Second, and equally important, each party applies judgment in determining how to translate the ACOSS results into revenue targets for each class. No party in this proceeding proposes to move all rate classes fully to cost-of-service parity in a single step. Instead, each party applies gradualism to moderate rate impacts and

[3] CAUSE-PA St. No. 1, at pp. 17-18.
[4] CAUSE-PA and I&E do not present an alternative revenue apportionment.

determine how far to move each respective class toward cost-based rates. As a result, the final revenue apportionment reflects both the underlying ACOSS results and each party's judgment regarding rate impacts and policy considerations. It is important to note that both the Company's proposal and OSBA's proposal set Rate N/NT to parity under the proposed revenue targets.

Q. How should the Commission consider these differences when evaluating the various proposals?

A. These differences demonstrate that revenue apportionment is not a mechanical outcome of any single cost-of-service study. Rather, it reflects a combination of analytical results and informed judgment applied by each party. The primary issue is how to reasonably apportion the approved revenue requirement among customer classes, balancing cost-of-service principles with gradualism and rate stability. As I described in my direct testimony, a cost of service study is a guide that provides directional insight into cost responsibility, but revenue allocation ultimately requires judgment, including consideration of gradualism, rate impacts, and policy objectives.

Q. Do the alternative revenue apportionment proposals presented by OCA, OSBA, or CAUSE-PA cause you to modify your recommendation?

A. No, they do not.

Q. Why do you continue to support the Company's proposed revenue apportionment?

A. I continue to support the Company's proposed revenue apportionment because it appropriately balances the two principal objectives that should guide revenue assignment in a general rate proceeding: first, moving class revenues closer to each class's indicated cost of service; and second, mitigating abrupt customer impacts through gradualism. The Company's proposal was expressly developed using the ACOSS as the primary analytical benchmark, while also moderating the pace at which under- and over-recovering classes are moved toward parity. In my view, that produces a reasonable and measured progression toward more cost-based rates.

With respect to the OCA proposal, its recommended apportionment is derivative of OCA's alternative ACOSS methodology, which I do not support for the reasons discussed below in my rebuttal testimony. Because I do not agree with OCA's underlying cost responsibility indications, I likewise do not agree that OCA's modified revenue movements provide a superior result.

Q. Do you agree with the OCA, OSBA, and CAUSE-PA recommendations to reject the rate decreases proposed for Rate XD and Rate IS?

A. No, I do not. Witness Deupree's justification for this recommendation is not reasonable. Both versions of the ACOSS, UGI Gas's and OCA's, show a revenue surplus for Rate XD and Rate IS.[5] OCA Witness Deupree fails to define how they assess the level of fairness outside of their subjective interpretations. This is why regulators across the country and the PUC look at the cost to serve each class as a guide to what rates are fair to those classes.

[5] UGI Gas, Exhibit D, Schedule 1, line 57, and OCA Exhibit MWD-5, line 20.

If fairness was not measured by the relationship between what costs are caused by the customers and what costs they pay for, then no regulatory commission would require a class cost of service to be filed with a rate case. They could rely on other subjective definitions of fairness.

Witness Ewen's disagreement to reduce Rate XD and Rate IS is based on his belief that "[t]hese customers are subject to negotiated rates, which have already been accepted by the customers."[6] I do not disagree that the rates applicable to Rate XD and Rate IS customers are subject to negotiated rates and are therefore not being modified in this proceeding. However, Witness Ewen's characterization overlooks the fact that the minor reduction shown for these classes is not the result of a discretionary decrease to those negotiated rates. Rather, as explained in my direct testimony,[7] it reflects the expiration and reset to zero of the Distribution System Improvement Charge ("DSIC") surcharge upon implementation of new base rates. Accordingly, while the proof of revenue reflects a small reduction in total revenues collected from the class, the underlying negotiated transportation rates paid by Rate XD and Rate IS customers remain unchanged. In that respect, the Company's proposal is already consistent with Witness Ewen's stated objective that these customers not receive a substantive rate adjustment in this proceeding. For the same reasons stated above, Witness Cicero's recommendation has no merit. In short, the very minor percentage decreases to Rate XD and Rate IS are a mechanical outcome of the rolling in of the DSIC costs into non-negotiated base rates. Additionally, the ACOSS shows that recovering these costs through DSIC, and thus partially from Rate XD and Rate IS, has led to an increase in the amount by which these classes' revenues exceed their cost of

[6] OSBA St. No. 1, at p. 12.
[7] UGI Gas St. No. 11, at p. 20.

service, which ultimately benefits other customer classes that are under contributing toward their cost of service.

Therefore, the Company's revenues should be allocated amongst the customer classes reflecting the results of the ACOSS that I prepared. The resulting movement of classes towards the overall system rate of return is consistent with regulatory practice and in the best interest of all customers. Rate XD and Rate IS customers represent a potential bypass risk. If pushed to do so by uncompetitive rates, their departure would reduce overall system revenue, ultimately shifting the recovery of fixed distribution costs to other customer classes.

III. ALLOCATED CLASS COST OF SERVICE STUDY

Q. How does OCA Witness Deupree disagree with the Company's ACOSS?

A. Witness Deupree disagrees with the Company's use of the Average and Excess ("A&E") methodology for distribution mains in the Company's ACOSS. He states that the A&E methodology fundamentally distorts the results by weighting the allocator towards lower load factor customers like residential customers. Therefore, he instead recommends using the Peak and Average ("P&A") methodology with a weighting based on the system load factors, producing a weight of 42.36% towards the demand portion of the method.[8]

[8] OCA St. 1, at pp. 48, 54.

Q. Please explain the key considerations in selecting an allocator for distribution mains in an ACOSS.

A. An ACOSS is intended to allocate utility costs in a manner that reflects the factors that actually drive those costs. In addition, distribution mains reflect two cost-causative realities. First, mains investment is driven by the need to connect and maintain an integrated delivery grid for a given number and geographic dispersion of customers (a customer-related driver of system extent). Second, mains must be sized to provide sufficient capacity to serve coincident peak-day requirements safely and reliably (a demand-related driver of system capacity). A reasonable allocator should recognize both drivers. Further, a system built to accommodate only average demand would be incapable of serving customers during periods of highest usage and would fail to provide safe and reliable service. Instead, mains are designed to withstand the pressures and flow requirements associated with peak system demand, often with additional margin to account for uncertainty and future growth.

Q. If both customer-related and demand-related factors drive distribution mains investment, why should the allocator recognize an average-demand component at all?

A. In selecting an allocator for distribution mains, it is appropriate to consider both (i) cost causation principles and (ii) the Commission's precedent regarding what methods are reasonable and administrable. Here, the Company selected an approach that is fully aligned with Commission precedent and that reflects the two principal drivers of mains investment. Typically, when reading through orders disallowing a customer component of mains or approving a method that incorporates annual usage, it appears that the stated rationale is

either premised upon the "annual gas delivery function" as the reason for the utility's existence or reflects a confusion of cost allocation concepts with rate design (i.e., allowing the method of recovering costs to impact the method of allocating those costs). Those policy considerations may influence outcomes, but they do not change the underlying engineering reality that mains are installed to connect customers and are sized to meet peak-day requirements.

This evolution in thinking is also reflected at the federal level: while the Federal Power Commission and later the Federal Energy Regulatory Commission ("FERC") historically used Seaboard-style cost classification for pipeline ratemaking, the FERC has since moved away from that approach in favor of methods intended to more directly reflect fixed-cost recovery and market-structure objectives. In this proceeding, the Company's selected method recognizes the concerns raised by parties who wish to incorporate an "annual delivery" concept by explicitly reflecting an average-demand component.

Lastly, to the extent any allocator incorporates an "average-use" concept, it should do so in a way that does not obscure the separate peak-capacity driver that governs main sizing.

The key is that peak-related demand remains the dominant cost driver because it is peak demand that determines how large the system must be. The A&E methodology reflects this by (1) recognizing an average-demand component and (2) separately measuring the demand in excess of average, which is the incremental component most directly associated with additional capacity and main size. This structure provides a more direct way to reflect an "average usage" concept without embedding the average component inside the peak term, as occurs under P&A.

Q. Why is OCA Witness Deupree's proposed 42.36/57.64 P&A weighting[9] inappropriate for allocating distribution mains?

A. Witness Deupree's proposal to weight P&A using the system load factor represents a fundamental misunderstanding of how distribution mains are designed and what drives their cost. Under this proposal, average demand would receive nearly 58% of the weight, while peak demand would receive only approximately 42%. This implies that average usage is the dominant driver of distribution main investment. That conclusion is inconsistent with both engineering reality and basic logic.

A system designed to withstand only average demand would fail. A system designed to withstand conditions somewhere between average and peak demand would also fail. In fact, even systems designed for current peak demand may require upgrades if a new system peak occurs or is projected to occur at design conditions. Distribution mains are therefore designed not merely around today's peak, but around the ability to safely handle extreme and potentially increasing system demands. Using a load-factor-based weighting effectively treats distribution mains as if they were sized based on how evenly customers use the system over time. That is not how mains are designed, and it is not what drives their cost. Average demand does not determine pipe diameter, wall thickness, or reinforcement requirements. Rather, peak conditions do. As a result, Witness Deupree's proposed 42.36/57.64 weighting places excessive and unjustified emphasis on average demand and severely understates the role of peak demand in driving mains investment.

[9] OCA St. 1, at p. 54.

Q. Does the P&A methodology raise additional concerns beyond improper weighting?

A. Yes. The P&A methodology inherently double-counts average demand. Under P&A, mains costs are allocated partly based on average demand and partly based on peak demand. Because peak demand necessarily includes average demand, the average component is counted twice: once explicitly as average demand, and again as part of the peak measure. In contrast, the A&E methodology avoids this problem by clearly separating average demand from the demand that exists in excess of average. Each component is counted once, and only once, which results in a cleaner and more accurate allocation. The double-counting inherent in P&A becomes even more problematic when the peak weight is reduced below 50 percent, as Witness Deupree has advocated in this proceeding. Doing so magnifies the influence of average demand, which is already embedded in both components of the P&A formula.

Q. What is the practical impact of this double-counting on class cost responsibility?

A. Double-counting average demand systematically distorts class cost responsibility. Customer classes with highly temperature-sensitive usage, such as residential customers, tend to have lower load factors and place significant demands on the system during peak conditions. When peak demand is understated and average demand is overstated, these classes are assigned less than their appropriate share of mains costs. At the same time, customer classes with flatter usage profiles and higher load factors are assigned more mains costs than they actually cause. This outcome is inconsistent with cost causation and undermines the fundamental purpose of the ACOSS.

Q. OCA Witness Deupree argues that the A&E methodology disproportionately shifts distribution mains costs to customer classes with lower load factors and characterizes this outcome as a distortion.[10] How do you respond to this claim?

A. First, it is important to return to the two primary cost drivers for distribution mains: (1) the need to extend mains to connect customers to the system and maintain an integrated system (a customer-related driver of system extent), and (2) the need to install sufficient pipe size to meet capacity requirements under coincident peak conditions (a demand-related driver of system capacity). Witness Deupree's focus on load factor speaks only to one aspect of system use and does not, by itself, capture the customer-driven requirement to extend and interconnect mains across the service territory. Smaller, lower load-factor customers, particularly in areas with lower customer density, can require substantial lengths of mains to connect and interconnect, even though their average use per customer is lower.

While OCA Witness Deupree is correct that the A&E methodology assigns a larger share of distribution mains costs to customer classes with lower load factors, characterizing this result as a "distortion" is incorrect. On the contrary, it reflects the accurate operation of cost causation principles as applied to the design and function of the distribution system. Customer classes with lower load factors tend to have highly temperature-sensitive usage that drives system demand during peak periods. These peaks are precisely the conditions that determine the required size, capacity, and cost of distribution mains. As a result, those customer classes impose greater demands on the system when it matters most from a design perspective, even if their average usage over time is lower. The A&E methodology is

[10] OCA St. 1, at p. 52.

designed to capture this relationship explicitly. By separating average demand from the demand in excess of average, A&E assigns cost responsibility in a manner that reflects how much incremental system capacity is needed to serve peak conditions. When classes with lower load factors are assigned a greater share of mains costs under A&E, that outcome is evidence that the methodology is functioning as intended, not a distortion.

By contrast, the P&A methodology masks this relationship by embedding average demand within the peak demand component. When peak weighting is further reduced, such as under OCA's proposed 42.36/57.64 weighting, the methodology increasingly shifts costs away from those classes that drive peak system requirements and toward classes with flatter load profiles. That result does not reflect system design or cost causation and instead produces a subsidization of peak-driving customers by more load-factor-efficient customers.

In short, it is neither anomalous nor inequitable that A&E results in higher cost responsibility for low-load-factor classes. It is a direct and appropriate recognition that those classes necessitate more main investments and greater system capacity. Labeling this outcome as a distortion reverses the logic of cost causation and ignores the fundamental purpose of an ACOSS.

Q. Has the Commission addressed the appropriate methodology for allocating distribution mains?

A. Yes. The Commission has explicitly endorsed the A&E methodology for allocating distribution mains and has rejected P&A for precisely the reasons discussed above. In Docket No. R-2020-3018929, the Commission found that PECO Energy Company – Gas

Division's ("PECO") use of the A&E methodology was "reasonable and acceptable for an NGDC because it aligns with cost causation principles and the design of PECO's distribution system."[11] The Commission further noted that this was not a novel determination, citing its earlier approval of A&E in the 2007 PPL Gas proceeding.

Importantly, the Commission emphasized that excess demand is a principal driver of mains investment and stated that "the excess demand component of PECO's distribution mains system garners considerable weight in the balance of mains costs."[12] The Commission also explicitly found that P&A double-counts average demand, leading to distorted cost responsibility, particularly for residential customers with temperature-sensitive usage. Based on these findings, the Commission concluded that A&E is "more reflective of an accurate representation" of distribution mains systems.[13]

Q. Did any other witness evaluate the Company's ACOSS and its use of the A&E methodology, and if so, what conclusions were reached?

A. Yes. OSBA presented direct testimony from Witness Ewen, who was specifically tasked with reviewing the Company's cost allocation, revenue allocation, and rate design proposals to determine whether they are consistent with sound regulatory economics and are fair and reasonable to customers, including small business customers. After completing this review, Witness Ewen identified no concerns with the Company's ACOSS. He concluded that the Company's cost allocation model is consistent with cost allocation methods that the Commission has previously accepted and does not produce unreasonable

[11] *Pa. PUC v. PECO Energy Co. – Gas Div.*, Docket Nos. R-2020-3018929, et al., p. 228-29 (Order entered June 22, 2021).
[12] *Id.*, p. 229.
[13] *Id.*, p. 230.

or inappropriate outcomes. In his testimony, he expressly acknowledged the use of A&E as one of the traditional and accepted approaches for allocating distribution mains costs and did not characterize the Company's application of that methodology as flawed, distortive, or inconsistent with cost causation principles.[14]

Q. In summary, how should the Commission evaluate the methodologies proposed in this proceeding?

A. Witness Deupree's proposal to apply a 42.36/57.64 weighting materially shifts emphasis away from peak-driven capacity requirements and further magnifies the structural issues inherent in P&A. If the goal is to employ a method that reflects average usage while still recognizing the capacity-driven nature of mains, A&E provides a more direct and internally consistent way to do so than a load-factor-weighted P&A approach. Accordingly, the Company's use of A&E is reasonable and supported.

IV. CUSTOMER CHARGES

Q. Please summarize the Company's proposed customer charge adjustments in this proceeding.

A. The Company proposes to increase the monthly customer charges for Rates R, N, and DS as part of a movement toward improved recovery of fixed customer-related costs through the customer charge. Specifically, the Company proposes to increase the Rate R customer charge from $16.25 to $23.00, the Rate N customer charge from $36.42 to $39.00, and the Rate DS customer charge from $300.00 to $353.00. As shown in Table 6 of my direct

[14] OSBA St. No. 1, at p. 10.

testimony, each of these proposed charges remains materially below the customer-related unit cost identified in the Company's ACOSS. For example, the proposed Rate R customer charge of $23.00 remains well below the ACOSS-indicated customer-related cost of $54.03. Accordingly, the Company is not proposing full recovery of customer-related costs through the monthly charge, but rather a measured step toward more cost-reflective recovery consistent with prior Commission precedent recognizing these categories of customer-related costs as appropriate for inclusion in a customer charge.

Q. Please summarize the principal positions advanced by the parties regarding the Company's proposed customer charge adjustments.

A. Both OCA and CAUSE-PA oppose the Company's proposed increases to the monthly customer charges, particularly for residential customers. Witness Deupree recommends that the Commission reject the proposed increases to the customer charges for Rates R and N and retain the current charges or, alternatively, limit any increase to the same percentage increase assigned to each class. In support of that recommendation, he states that customer charges were increased in the Company's prior rate proceeding, that current charges already recover a portion of customer-related costs, that additional fixed charge recovery places a proportionately greater burden on lower-use customers, and that higher customer charges may weaken conservation and energy efficiency price signals.[15] Similarly, CAUSE-PA raises concerns that increasing fixed monthly charges reduces customers' ability to manage bills through usage reductions and places added pressure on customers facing affordability challenges.[16]

[15] OCA St. 1, at p. 68.
[16] CAUSE-PA St. No. 1, at p. 51.

Q. Witness Deupree claims that the customer charge includes costs that are not directly related to providing service to customers and raises concerns about the Company's proposed residential customer charge because it is higher than the charges of other natural gas distribution companies ("NGDCs") in Pennsylvania.[17] How is this comparison relevant to the evaluation of the appropriateness of the charge?

A. Witness Deupree's statement about the customer charge including costs that are not directly related to providing service to customers is untrue. As indicated in my direct testimony, the Company's proposed residential customer charge of $23.00 is well below the customer-related unit cost of $54.03, which reflects cost components historically approved by the Commission for recovery through the customer charge.[18] In addition, Witness Deupree's comparison overlooks the fundamental considerations that should guide the design of utility rates. Except for the commodity cost of natural gas, the natural gas utility system is predominantly a fixed-cost system. These fixed costs are incurred to design and construct a delivery network capable of meeting the system-wide peak demand during extreme cold weather conditions. This infrastructure must be maintained and available year-round to serve customers reliably, regardless of actual daily usage. Importantly, these costs do not decrease when customer usage declines during warmer periods, only commodity-related costs fluctuate with usage. Therefore, it is appropriate for rates to be designed in a manner that aligns with the underlying cost structure of the system. Specifically, fixed costs should be recovered through fixed charges, making the

[17] OCA St. 1, at p. 64.
[18] UGI Gas St. No. 11, at pp. 26-27.

level of the Company's proposed customer charge a reflection of cost causation rather than a comparison to other utilities.

Q. How do you respond to OCA Witness Deupree's claim that a higher customer charge is inconsistent with the promotion of energy conservation and efficiency goals?[19]

A. Although I understand Witness Deupree's concern, rate design must balance multiple regulatory objectives: cost causation, revenue stability, fairness, and yes, price signals that support efficiency. It is important to recognize that the customer charge is intended to recover fixed costs that do not vary with usage, such as meter reading, billing, and service line maintenance. These costs are incurred to serve customers regardless of how much gas they use. Placing too much emphasis on conservation in the design of the customer charge risks distorting cost recovery by shifting fixed costs into the volumetric rate. This can lead to under-recovery during periods of low usage and may result in unstable rates over time. Moreover, energy efficiency can still be promoted through other aspects of the rate structure, including appropriately designed volumetric commodity charges that send efficient price signals reflecting usage, as well as through targeted efficiency programs, without compromising the integrity of fixed cost recovery. Therefore, while conservation is an important policy goal, it should not override the fundamental principle that fixed costs are most appropriately recovered through fixed charges. The Company's proposed customer charge reflects this principle while still leaving room for usage-based price signals in the volumetric portion of the rate.

[19] OCA St. 1, at p. 65.

Under UGI Gas's proposed $23.00 monthly residential customer charge, approximately 79.9% of residential revenues would still be recovered through volumetric delivery charges. Under the OCA's $16.25 proposal, that figure is approximately 85.8%. In either case, the overwhelming majority of a residential customer's bill would still be usage-based. This clearly demonstrates that customers continue to have significant opportunities to lower their gas bills through energy efficiency measures, conservation, and behavioral changes. The suggestion that a higher customer charge eliminates the incentive or ability to reduce bills is simply not supported by the numbers.

Q. What definition of conservation should be utilized in the context of setting distribution rates?

A. Conservation, in the context of distribution rate design, should be understood as the wise and efficient use of utility resources—not merely the reduction of energy consumption. When evaluating the appropriate level of the fixed monthly customer charge, it is important to recognize that many of a gas utility's distribution costs are incurred regardless of usage. These include the costs to connect customers to the system and maintain infrastructure capable of meeting customer requirements. Designing rates that recover these fixed costs through a volumetric rate can mislead customers into thinking they can avoid these costs by reducing usage, when in fact, the utility's cost to serve them remains unchanged. This misalignment can lead to inefficient price signals, as some customers may invest time or money to reduce their bills in ways that do not actually reduce system costs. In effect, those unrecovered fixed costs must then be shifted to other customers and will likely return, at least in part, to impact the customer undertaking the conservation investments as such fixed

costs are recalculated into rate designs during subsequent rate case proceedings. This dynamic creates a zero-sum situation, where volumetric charge related savings for one customer result in increased costs for others, and even for themselves, without any overall efficiency gains for the system. In short, economically inefficient rate designs result in a misallocation of societal resources where individual decision-making is skewed by inaccurate prices and the results of their decisions have unintended consequences.

Q. How do utility customers respond to price signals and changes in rates?

A. Customers respond to price signals in varied and often inconsistent ways. A change in consumption patterns is not solely driven by pricing, it is influenced by factors such as appliance efficiency, appliance technology, building insulation, access to alternative fuels, weather, and socioeconomic conditions. Additionally, customer response to price changes depends on both their ability and willingness to adjust behavior. Some customers may not prioritize investments in energy efficiency improvements, while others may not see enough benefit from marginal price changes to justify altering their usage. Small increases (such as from a $16.25 to a $23.00 customer charge) may not be noticeable enough to prompt any behavioral change. It is also important to note that natural gas is often treated as a necessity, especially for heating in colder climates, meaning consumption is less elastic. Many customers prioritize comfort and safety over potential savings, and some may not actively track their energy usage at all. Therefore, assuming that small adjustments in fixed charges will meaningfully impact conservation behavior is not supported by observed customer behavior or economic fundamentals.

Q. OCA Witness Deupree states that higher customer charges disproportionately impact lower-use residential customers, which he contends tend to be lower-income customers, and references OCA Witness Colton as discussing this concept in more detail.[20] How do you respond?

A. Neither Witness Deupree nor Witness Colton provides Company-specific data or analysis demonstrating that lower-use residential customers are generally lower-income customers. Their criticism rests on a generalized assumption rather than evidence concerning the Company's actual customer population. By contrast, the Company examined this issue using its historical residential billing data and found that confirmed low-income residential customers use more gas on average than residential non-low-income customers.[21] This directly contradicts the premise underlying OCA's argument. Accordingly, the assertion that the proposed customer charge disproportionately harms low-income customers simply because it affects lower-use customers is not supported by record evidence.

Q. CAUSE-PA Witness Cicero claims that "[t]he proposed increase in the fixed monthly customer charge weakens the ability of low income households to save money on their bills each month because less of their bill is dependent on the volume of gas they consume."[22] How do you respond?

A. As addressed in my response to OCA Witness Deupree, the concern that an increase in the fixed customer charge will significantly weaken low-income customers' ability to manage or reduce their bills is unfounded.

[20] OCA St. 1, at p. 68.
[21] UGI Gas St. No. 11, at pp. 28-29.
[22] CAUSE-PA St. No. 1, at p. 50.

Q. CAUSE-PA Witness Cicero acknowledges your calculation that a residential customer using approximately 78.6 Mcf annually represents the breakeven point under the Company's proposed residential customer charge, but he argues that average usage does not reflect the full range of customer consumption patterns.[23] How do you respond?

A. Witness Cicero is correct that not every residential customer uses gas at exactly the class average, so individual customer bill impacts will vary depending on actual consumption. That fact, however, does not undermine the usefulness of the breakeven analysis. The purpose of my calculation was not to suggest that all customers will experience identical bill impacts; rather, it was to illustrate the point at which the increase in the monthly customer charge is offset by the corresponding reduction in volumetric delivery rates. This provides a reasonable benchmark for understanding how the proposed rate design functions across the class. By definition, some customers with usage above that level will experience net savings while some customers below that level may experience modest increases. However, that is true in virtually any rate design change involving a shift in fixed and variable recovery. The relevant point is that the proposal better aligns the recovery of customer-related fixed costs with the fixed charge while preserving substantial volumetric pricing signals, and the existence of a range of consumption patterns does not alter that ratemaking principle.

[23] CAUSE-PA St. No. 1, at pp. 51-52.

Q. What price signal does the current residential rate structure send to customers regarding the cost of using natural gas?

A. Under the current residential rate structure, approximately 84% of fixed distribution costs are recovered through volumetric charges. As a result, the per-unit price of gas delivery embedded in the volumetric rate materially exceeds the actual marginal cost of providing service. Based on the Company's current rates, customers face an effective delivered price signal of approximately thirteen dollars per Mcf ($13.1), while the underlying marginal cost of commodity gas cost is closer to seven dollars per Mcf ($6.8). This means customers are making consumption decisions based on a price signal that is approximately two times (2x) the actual incremental cost of using natural gas. The impact is most pronounced during the winter when demand for natural gas increases. During these months, customers experience higher and less predictable monthly bills, and the inflated volumetric rate makes each additional unit of usage appear far more expensive than it actually is. In addition, during the coldest periods, and particularly in colder than normal winters, commodity prices often increase - sometimes significantly, further exacerbating the effect. For many households, particularly those with limited flexibility to reduce usage, this results in the perception, and often the reality, that natural gas service is unaffordable at the time when it is needed most, even though the underlying cost to serve incremental usage is materially lower.

Q. Please expand on how a higher customer charge would impact different segments of the Company's population.

A. All else being equal, higher customer charges necessitate lower variable charges. The collection of costs through fixed or volumetric charges is the only means of collecting the revenue to cover costs for a specific customer class. The total revenue target for the class does not change, just which component is designed to recover what portion of the total revenue target. Most importantly, the choice between volumetric and fixed recovery does change how and when customers pay those costs over the course of the year. This distinction is important because affordability is not determined solely by total annual bills, but also by the timing and variability of monthly bills.

For many households, particularly low-income customers, expenses are managed on a weekly, bi-weekly, or monthly basis, with limited financial flexibility to absorb large fluctuations in costs. Research consistently shows that a significant share of low-income households have little to no liquid savings available to manage unexpected or seasonal increases in expenses. As a result, rate designs that concentrate cost recovery in volumetric charges can create sharp bill increases during the winter months, when usage is highest and energy needs are least discretionary.

In contrast, recovering a reasonable portion of costs through a fixed monthly charge helps moderate seasonal bill volatility and provides greater predictability for household budgeting. This is particularly important for vulnerable customers who may not have the ability to reduce usage in response to higher winter prices. It is also important to recognize that customers are not equally positioned to respond to volumetric price signals. Higher-income households may have the financial means to invest in energy efficiency

improvements, otherwise reduce consumption, or simply pay more for gas usage. In contrast, lower-income households—especially renters or those in less efficient housing—often lack the ability to make such investments and may instead respond by reducing essential usage in ways that negatively impact their standard of living.

Further, recovering fixed costs in volumetric charges places regressive burdens on low-income households who have to make decisions to reduce their gas usage that impact their quality of life. Recovering fixed costs in volumetric charges increases the burden on some vulnerable households during the coldest months, forcing some households to make tough decisions. These households might choose between gas use for basic human needs, such as heat, hot water and cooking or other choices that add value to their lives (e.g., food, medical care, clothing, personal care products).

Accordingly, recovering a greater share of fixed costs through volumetric charges can create regressive outcomes by concentrating costs in periods when customers are least able to respond. A more balanced rate design, such as the Company's proposal, mitigates these effects by improving bill stability while still preserving appropriate price signals.

Notably, the concerns raised by CAUSE-PA and OCA themselves underscore several of these same customer realities. These witnesses emphasize that many low-income customers have limited financial flexibility, face competing essential household expenses, and have constrained ability to materially reduce winter heating usage.[24] I agree that these are important considerations. Where I differ is in the inference drawn from those facts. In my view, because many vulnerable customers cannot meaningfully avoid winter heating usage, concentrating a greater share of fixed distribution cost recovery in volumetric winter

[24] CAUSE-PA St. No. 1, at pp.17, 20, 26-27; OCA St.6, at pp. 26-28.

charges can intensify monthly bill pressure at precisely the time those customers are least able to respond. The positions of CAUSE-PA and OCA are internally inconsistent: they want to send a price signal, but they also acknowledge that some customers, and in particular the most vulnerable, cannot meaningfully respond to it. It is also appropriate to recognize that ultimately the availability of the Company's low-income Customer Assistance Program ("CAP") serves to support affordability for low-income customers, and its design is such that most customers receive bills that are income based and fully fixed-price in terms of rate design.

Q. Have other jurisdictions recently recognized the impact of recovering fixed costs through volumetric charges on low-income customers?

A. Yes. Most recently, in its order in the Docket Cause No. 45990 issued on February 3rd, 2025, the Indiana Utility Regulatory Commission recognized the following:

> (…) we are persuaded by witness Taylor's evidence that frequently low-income customers are harmed by recovery of fixed costs through a volumetric charge. We are further persuaded that the TDSIC [Transmission, Distribution, and Storage System Improvement Charges] distribution costs should continue to be recovered through a fixed charge. These are fixed costs, and recovery through a volumetric charge would send inefficient price signals and would work to the detriment of those low-income customers who are higher volume users. [Section xi.6, Commission Discussion and Findings, page 113]

Q. How do you respond to the recommendations of OCA, CAUSE-PA, and I&E that the proposed monthly customer charges be scaled back proportionately if the Commission approves a lower revenue requirement?[25]

A. I disagree with their recommendation. Rate design should be based on the cost to serve, not applied as a function of comparing UGI Gas's revenue requirement request with what is authorized. As I have mentioned previously, the customer charge specifically reflects the fixed costs of providing service to a residential customer. Scaling back the customer charge merely to match a reduced revenue requirement would disconnect the rate design from cost causation principles and potentially result in an under-recovery of fixed costs. This shift would necessarily increase the portion of revenue recovered through volumetric charges, distorting price signals and potentially creating intra-class subsidies between low- and high-use customers. As noted by NARUC in its Gas Rate Design Manual, "Ideally, the customer charge should recover all customer costs."[26] The Company's proposed customer charges, which are below the customer related unit cost identified in the ACOSS,[27] were developed to reflect these cost-based principles and should be evaluated independently of the total revenue level ultimately approved by the Commission.

[25] OCA St. 1, at p. 69; CAUSE-PA St. No. 1, at p. 55; I&E St. No. 1, at p. 17.
[26] National Association of Regulatory Utility Commissioners (NARUC), *Gas Rate Design Manual*, June 1989, p. 49.
[27] UGI Gas St. No. 11, at p. 26.

V. WEATHER NORMALIZATION ADJUSTMENT

Q. Please summarize the Company's proposal regarding the WNA and describe the key components of the mechanism.

A. The Company proposes to continue its existing WNA Rider for an additional five-year pilot period through October 31, 2032, with modifications intended to improve the accuracy and consistency of the mechanism. Under the full proposal, the WNA would continue to apply only to the Company's weather-sensitive Residential and Small Commercial customer classes, excluding CAP customers, during the heating season months of October through April. The mechanism adjusts only the distribution volumetric portion of customer bills when actual weather materially differs from normal weather, thereby reducing abnormal weather-related volatility in both customer bills and Company revenues. The WNA also retains a 3% deadband and other customer protections previously agreed upon in past cases.[28] Lastly, the Company proposed to replace the current 15-year normal HDD baseline with a 10-year historical average ending December 31, 2024, and to update that 10-year normal in each future base rate proceeding so that the same normalized weather assumptions used to establish billing determinants in base rates are also used in the operation of the WNA. No party opposed this update to the stated 10-year normal.

Q. What are the other parties' positions in this case regarding the WNA?

A. The other parties take differing positions on the Company's proposed continuation of the WNA, but all recommend some degree of modification or additional limitation. OCA opposes continuation of the WNA as proposed and recommends that the Commission

[28] UGI Gas St. No. 11, at p. 26.

either reject the renewal of the pilot altogether or, at a minimum, significantly tighten the mechanism arguing that it has resulted in substantial net surcharges to customers and shifts weather-related revenue risk away from the Company. OCA also objects to the Company's proposal to continue coupling the WNA with an increased residential customer charge, arguing that the combination further insulates the Company from normal volumetric sales risk.[29]

OSBA does not oppose the concept of weather normalization but recommends that any continued WNA be narrowed to provide stronger customer protections, including changes intended to reduce the magnitude and frequency of customer surcharges and supports only a limited two-year WNA extension pending further evaluation.[30]

I&E likewise does not oppose extending the WNA pilot but recommends increasing the deadband from 3% to 5%, consistent with recent Commission precedent in Columbia Gas of Pennsylvania, Inc. ("Columbia Gas"), arguing that a broader range of ordinary weather variation should remain the Company's responsibility before any WNA adjustment is triggered.[31]

Finally, CAUSE-PA takes the strongest position against the WNA, asserting that the rider is unjust and unreasonable, is disproportionately harmful to low-income customers, and should be permitted to expire at the end of the current pilot term rather than be renewed. CAUSE-PA argues that the WNA, particularly when combined with the proposed increase in the residential customer charge, improperly locks in Company revenues by transferring normal weather and usage risk from shareholders to customers.[32]

[29] OCA St. 1, at pp. 35-39.
[30] OSBA St. No. 1, at pp. 15-17.
[31] I&E St. No. 3, at pp. 15-16.
[32] CAUSE-PA St. No. 1, at pp. 57-63.

Q. Please summarize OCA Witness Deupree's claim regarding WNA charges outweighing credits.[33]

A. Witness Deupree asserts that, since the implementation of the WNA pilot, charges assessed under the WNA have outweighed credits provided to customers, such that the WNA has not produced a "balanced" outcome. He relies on this characterization to argue that the WNA has only increased customer bills on a net basis and should therefore be discontinued or substantially limited.

Q. How do you respond to Witness Deupree's claim that the WNA has not produced a balanced outcome?[34]

A. Witness Deupree's conclusion is driven by the interaction between the methodology used to select weather normal and prevailing weather conditions during the pilot period, which, when measured against a longer historical baseline, have tended to classify recent heating seasons as warmer than normal.

Under the existing lagged 15-year normal, the heating seasons during which the WNA has been in effect, beginning in November 2022, have generally been warmer than "normal," resulting in WNA charges to customers. In that context, the presence of net WNA charges reflects the expected operation of the mechanism and does not, standing alone, demonstrate that the WNA is structurally biased against customers or failing to function as designed.

[33] OCA St. 1, at p. 35.
[34] *Ibid.*

Additionally, whether the WNA produces a charge or a credit is highly sensitive to the choice of the weather normal. When the same billing months are recalculated using a 10-year normal, which more closely reflects recent weather patterns, both the magnitude and direction of WNA impacts change materially. A shorter normal reduces the extent to which recent heating seasons are classified as warmer than normal, thereby reducing associated WNA charges and increasing associated WNA credits. Table 2 below summarizes the WNA adjustments over the period during which the WNA has been in effect, as calculated under the existing 15-year normal and as recalculated using a 10-year normal applied to the effective rates in place during each heating season.

Table 2 – Comparison of WNA Charges/Credits Under 15 and 10 Year Normal (in millions)

WNA Month	Actual Total Residential and Commercial WNA Revenue 15-Year Normal	Estimated Total Residential and Commercial WNA Revenue 10-Year Normal
Nov-22	$1.54	$0.85
Dec-22	1.02	-0.46
Jan-23	6.15	3.35
Feb-23	11.00	6.64
Mar-23	9.19	3.92
Apr-23	4.31	2.44
May-23	0.49	0.00
2022-2023 Heating Season	**$33.70**	**$16.75**
Oct-23	$0.26	-$0.39
Nov-23	1.28	-0.31
Dec-23	2.27	0.89
Jan-24	8.17	4.38
Feb-24	9.08	4.72
Mar-24	11.85	6.24
Apr-24	4.91	1.99
May-24	2.92	2.92
2023-2024 Heating Season	**$40.72**	**$20.44**

WNA Month	Actual Total Residential and Commercial WNA Revenue 15-Year Normal	Estimated Total Residential and Commercial WNA Revenue 10-Year Normal
Oct-24	$0.80	$0.78
Nov-24	3.97	2.31
Dec-24	1.39	-0.60
Jan-25	-1.43	-5.17
Feb-25	-1.51	-5.37
Mar-25	4.41	0.85
Apr-25	5.75	2.81
May-25	2.95	3.40
2024-2025 Heating Season	**$16.31**	**-$1.00**
Oct-25	$0.37	-$0.23
Nov-25	-1.38	-2.63
Dec-25	-6.57	-9.31
Jan-26	-5.58	-7.66
Feb-26	-14.44	-17.25
Mar-26	0.30	1.02
2025-2026 Heating Season to Date	**$(27.30)**	**-$36.05**
Total WNA Collections/Credits	**$63.44**	**$0.13**

The monthly and seasonal results summarized in Table 2 demonstrate that observed WNA outcomes are strongly influenced by the weather normal used in the WNA mechanism. During the initial years of the WNA pilot, heating seasons were generally warmer than normal when measured against the existing 15-year baseline, resulting in net WNA charges that are an expected outcome of the mechanism's design. When the same billing months are evaluated using a 10-year normal that more closely reflects recent weather conditions, the magnitude of WNA adjustments is materially reduced.

The dependence on the selected normalization period remains evident in the most recent heating season. Under the 15-year normal, the WNA results in a substantial net

credit, reflecting colder-than-normal weather relative to that baseline. When recalculated using a 10-year normal, the same season produces a materially larger credit. These results show that conclusions regarding whether WNA charges outweigh credits are driven by baseline selection and prevailing weather conditions, rather than by any inherent imbalance in the structure or operation of the WNA mechanism itself. As demonstrated by the analysis above, the Company's proposal to move to a 10-year normal in this proceeding directly addresses Witness Deupree's concern that the WNA should provide a more balanced outcome.

Q. Does this indicate that the WNA amounts are higher than they should have been across this historical period when a 15-year normal was used?

A. No. What this analysis indicates is that the estimated usage was higher than anticipated with the 15-year normal, and as such, rates were lower than they would have been under a 10-year normal. The WNA mechanism worked correctly by adjusting bills to reflect actual weather when it differed from the normal assumption, but the 15-year normal weather basis was not as closely reflective of recent warming trends when compared to the 10-year normal. In short, the WNA does not operate in a vacuum; it operates in the context of, and in accord with, the actual normal weather used to define usage, which directly impacts the rates customers pay.

Q. Witness Deupree suggests that "budget billing" offers the same features as the WNA when it comes to normalizing billing.[35] How do you respond?

A. Budget billing and the WNA serve fundamentally different purposes. The WNA is an alternative ratemaking mechanism intended to stabilize distribution margin recovery and moderate customer bill impacts associated with deviations between actual and normal weather (an external factor outside the Company's and customers' control). By contrast, UGI Gas's Budget Billing Program, is a voluntary bill payment option that allows customers to pay levelized amounts based on prior usage, with periodic true-ups to reconcile the budgeted payments to the customer's actual billed usage.

Critically, because the Budget Billing Program trues up to actual usage, it does not "normalize" usage to normal weather conditions. For example, if weather is colder than normal, a Budget Billing customer will still ultimately pay for the higher actual usage through the next true-up. Under the WNA, however, that same customer could receive a credit for the portion of usage attributable to weather that was colder than normal, because the mechanism adjusts billed usage toward a normal-weather benchmark. In other words, the Budget Billing Program can smooth the timing of payments, but it does not change rate design, does not address weather-driven deviations from normal consumption, and therefore does not mitigate the corresponding bill and revenue volatility that the WNA is designed to address.

[35] OCA St. 1, at p. 31.

Q. How do you respond to Witness Deupree statement that the WNA is a "one-way surcharge mechanism"[36]?

A. Witness Deupree's characterization of the WNA as a "one-way surcharge mechanism" is inaccurate and is contradicted by the very data he presents. As shown in his summary of the Company's WNA Annual Reports,[37] the WNA has operated in both directions during the pilot period, producing customer surcharges in colder-than-normal periods and customer credits in warmer-than-normal periods, exactly as the mechanism was designed to do. In fact, during the 2024-2025 heating season, the WNA produced net customer credits in multiple months. Likewise, in the current 2025-2026 heating season, the WNA has produced substantial monthly customer credits in November through February, yielding cumulative net credits of approximately $27.6 million through the period reported.

Witness Deupree's conclusion appears to focus selectively on the first two years of the pilot, which experienced significantly warmer-than-normal weather and therefore generated net surcharges, while disregarding the more recent warmer-than-normal periods where the WNA flowed back to customers as intended. The table demonstrates that the WNA is not "one-way"; rather, it is a symmetrical weather normalization tool that adjusts revenues upward or downward depending entirely on actual weather relative to normal. The fact that the mechanism has recently produced significant net credits confirms that customers benefit when weather is colder than normal just as the Company is protected when weather is warmer than normal. Moreover, as demonstrated and discussed above, the move to a 10-year normal directly addresses Witness Deupree's desire for the WNA to produce more balanced outcomes.

[36] OCA St. 1, at p. 35.
[37] OCA St. 1, at p. 34, Table 1.

Q. OSBA Witness Ewen contends that the "use of a WNA mechanism means that a customer is being billed for a level of gas consumption that is not metered, but is only estimated" and calls the WNA charge or credit "mysterious."[38] How do you respond?

A. I disagree with that characterization. First, customers' gas supply charges are still based on their actual metered usage. The WNA applies only to the delivery component and adjusts a weather-sensitive billing determinant using a defined, tariffed formula that compares actual HDD to the same "normal" HDD baseline used for ratemaking purposes, subject to a deadband. This adjustment does not create additional consumption or collect revenues unrelated to service provided. Second, while the WNA calculation is necessarily formula-based, it is no more "nuanced" than other tariffed riders that rely on objective inputs. In fact, by explicitly quantifying the impact of weather that differs from normal, the WNA can make the source of bill variation clearer.

Q. Witness Ewen asserts that the WNA "weakens price signals for energy conservation during extreme periods."[39] How do you respond?

A. I disagree. The WNA does not replace volumetric delivery rates or remove the linkage between usage and a customer's bill. Customers still pay for the gas they use, and they continue to benefit from conservation and efficiency through lower base-rate volumetric charges and lower gas costs. The WNA simply adjusts for abnormal deviations from normal weather conditions so that a customer's bill is less dependent on whether a

[38] OSBA St. No. 1, at p. 15.
[39] OSBA St. No. 1, at p. 16.

particular season is warmer or colder than normal. That design purpose is fundamentally different from, and does not preclude, conservation or efficiency efforts. As discussed above in this testimony, the choice between fixed and volumetric rates impacts price transparency and the accuracy of price signals to customers, ultimately impacting economic efficiency.

Q. Witness Ewen suggests that periods of unusually low actual HDD could cause the WNA formula to produce excessively large adjustment multipliers.[40] How do you respond?

A. Witness Ewen's concern is based on a hypothetical mathematical example rather than on actual working application of the Company's WNA pilot. Specifically, the Company's billing system prevents the application of excessively large adjustment multipliers by applying a limit to the WNA multiplier that may be used for billing. (Specifically, a factor no greater than 2.12 can be applied). This functionality has been in place since the initial WNA implementation and prevents the type of excessive customer impact Witness Ewen's hypothetical implies via the application of prudent billing logic. Accordingly, Witness Ewen's theoretical scenario is moot under the Company's existing controls.

[40] *Ibid.*

Q. OSBA Witness Ewen suggests that the Company's WNA has effectively become a permanent feature of rates without the same level of regulatory scrutiny applied to other ratemaking proposals.[41] How do you respond?

A. I disagree with Witness Ewen's characterization. The Company's WNA has not continued absent regulatory scrutiny. To the contrary, it has been expressly presented, reviewed, and litigated in each of the Company's subsequent base rate proceedings since its initial approval, and the Company has also filed annual reports with the Commission regarding the operation of the WNA. In each case, the continuation or modification of the WNA has been subject to discovery, testimony, other parties' comment, and Commission evaluation as part of the overall rate case record. Thus, the WNA has not been operating as an unchecked or automatic permanent mechanism, but rather as a rider repeatedly examined by the Commission under full regulatory process. The fact that the Company now seeks an additional extension reflects the continued need for Commission authorization, not the absence of oversight.

Q. CAUSE-PA Witness Cicero states that "[t]he WNA requires an overly complicated and nuanced calculation that is difficult for customers to understand because it charges customers not for their actual usage but their hypothetical usage."[42] How do you respond?

A. I have already addressed the separate contention that the WNA charges customers for unmetered or estimated usage. The WNA does not charge customers for gas they did not use. Customers continue to pay for the actual gas commodity volumes reflected by their

[41] OSBA St. No. 1, at p. 17.
[42] OSBA St. No. 1, at p. 58.

metered usage. More specifically, the WNA adjusts only the recovery of authorized distribution revenues associated with providing gas distribution service, which remains available to customers regardless of short-term weather variations. The Company's distribution system, infrastructure, and obligation to serve customers remain in place and operational whether temperatures are warmer or colder than normal. In that respect, distribution service continues to be provided even during periods when weather-related usage declines.

With respect to Witness Cicero's additional claim that the mechanism is too complicated for customers to understand, the Company's customer experience does not support that assertion. As shown in Table 3, Company data regarding customer complaints about the WNA shows a relatively low number of complaints compared to the number of bills issued during the heating season and a significant decline over time. This is inconsistent with the claim that the rider is or has become a persistent or growing source of customer confusion.

Table 3 – WNA Related Complaints[43]

Year	Disputes	PUC Informal	PUC Formal
2022	7	2	None
2023	153	63	10
2024	31	22	2
2025	9	10	2
2026	None	None	None

[43] A customer may be counted multiple times in the data if the complaint proceeded from one process to the next.

Q. CAUSE-PA Witness Cicero states that the Company admitted in discovery that the WNA has no bearing on whether the Company can provide safe and reliable service and therefore concludes that the WNA serves only to maximize shareholder revenues.[44] How do you respond?

A. Witness Cicero misconstrues the Company's discovery response. The Company did not state that the WNA has no bearing on the Company's broader ability to sustain safe and reliable service. Rather, the Company explained that the WNA is not a physical operating mechanism that directly determines whether the system can function safely on a day-to-day basis. Instead, it is a rate design mechanism intended to address abnormal weather-driven volatility in customer bills and in the Company's recovery of its authorized distribution revenue requirement. By providing the Company with a more reasonable opportunity to recover revenues already approved by the Commission, the WNA supports the financial stability necessary to continue investing in system maintenance, aging infrastructure replacement, and other long-term reliability initiatives. Accordingly, the Company's response does not support Witness Cicero's conclusion that the WNA is merely a shareholder revenue maximization tool. Further, ratemaking mechanisms should not be judged solely on whether and how they impact a company's ability to provide safe and reliable service. This is simply a straw man argument where Witness Cicero advances a position (i.e., that the WNA should be judged on a metric irrelevant to its function) and then knocks it down by saying it does not meet that criteria.

[44] CAUSE-PA St. No. 1, at p. 62.

Q. Witness Cicero asserts that the WNA causes the Company to lose a significant incentive to operate efficiently because it allows UGI Gas to reach its projected revenue target regardless of operational performance.[45] How do you respond?

A. Witness Cicero incorrectly equates weather-related sales volatility with Company operating efficiency. The WNA does not insulate the Company from the consequences of inefficient operations, nor does it guarantee that the Company will achieve its authorized earnings. It addresses only one external factor outside of management's control and customers' control (abnormal deviations in customer usage caused by warmer or colder than normal weather). The Company remains fully subject to all traditional utility performance risks, including cost overruns, operating inefficiencies, capital execution risk, and the many other factors that determine whether it ultimately earns above or below its authorized return. Simply put, the Company cannot operate more efficiently to control the weather. The WNA therefore does not diminish incentives for prudent management; it merely reduces a source of revenue volatility unrelated to management performance.

Q. Witness Cicero claims that the WNA improperly shifts weather-related risk from the Company to customers in a manner that is inappropriate for a monopoly provider of essential utility service.[46] How do you respond?

A. I disagree with Witness Cicero's characterization. The WNA does not create an improper new entitlement to revenues divorced from actual service; rather, it is a ratemaking mechanism designed to align actual distribution revenue recovery with the normalized weather assumptions already embedded in the Company's approved base rates. The

[45] CAUSE-PA St. No. 1, at p. 63.
[46] CAUSE-PA St. No. 1, at pp. 58-59.

"weather-related risk" that Witness Cicero identifies is a product of the use of a test year for utility ratemaking, and the use of a calculated assumption for normal weather that is necessary to derive volumetric rates. The Company's authorized revenue requirement, necessary to recover its cost of service, and billing determinants are established using normal weather, not the random actual temperatures experienced in any single heating season. The "weather-related risk" goes in both directions, for the utility it undermines the ability to earn the Company's cost of service and for customers it increases bill volatility at a time where the overall rate design will make bills their highest (i.e., cold weather bills will be higher than warm weather bills due to high volumetric charges). This risk is not a benefit of ratemaking, as Witness Cicero implies; it is a negative consequence of the legacy ratemaking which is still applied in widespread form in Pennsylvania. The WNA, therefore, provides a solution that reduces the risk that the Commission approved cost of service will not be the amount customers pay. Without a WNA, the Company's opportunity to recover approved revenues would fluctuate materially based solely on warmer- or colder-than-normal weather conditions unrelated to Company management, prudence, or cost control, while customers would likewise be exposed to higher bills when weather is colder than normal. The WNA addresses that mismatch.

Q. What would be the impact of discontinuing or limiting the WNA as proposed by these parties?

A. Discontinuing or limiting the WNA, as proposed by OCA[47], OSBA,[48] I&E,[49] and CAUSE-PA[50] would remove or materially weaken the mechanism and reintroduce volatility into revenue recovery for both the Company and customers. The WNA serves as a two-sided buffer: it reduces the risk of under-recovery in mild winters and helps limit excessive charges in colder winters. In particular, when weather is unusually cold and customer bills are highest, the WNA helps moderate bill impacts; accordingly, modifications that reduce its effectiveness may harm customers. Likewise, exempting all confirmed low-income customers from the WNA would undermine the mechanism's fairness and consistency by creating intra-class cost shifts that require other customers to assume a disproportionate share of revenue stabilization. Additionally, as related to exempting low-income customers, it is important to recognize that as a result of agreement in the Company's last base rate proceeding, the WNA no longer applies to low-income CAP customers. Company Witness Cyndee S. Fang, UGI Gas Statement No. 16-R, discusses the affordability implications.

Moreover, to the extent certain parties rely on modifications recently adopted by the Commission in other proceedings, including Columbia Gas, as support for imposing similar limitations here, such reliance is misplaced. The Commission's determinations regarding WNA design are necessarily utility-specific and fact-dependent. The adoption of particular parameters in another company's proceeding does not establish a mandatory

[47]OCA St. 1, at pp. 36-38.
[48] OSBA St. No. 1, at p. 2.
[49]I&E St. No. 3, at p. 16.
[50]CAUSE-PA St. No. 1, at pp. 65-66.

statewide template that must automatically be imposed on UGI Gas absent record evidence demonstrating that such changes are appropriate for this Company's system, customer usage patterns, and weather normalization methodology. The Commission must evaluate UGI Gas's WNA proposal based on the evidentiary record developed in this case.

Q. What would be the impact of increasing the WNA deadband from 3% to 5%, as proposed by OCA, I&E, and CAUSE-PA[51]?

A. Increasing the deadband from 3% to 5% would materially weaken the WNA by expanding the range of weather variation for which no adjustment is made. As a result, a larger share of abnormal weather risk would remain outside the mechanism, reducing the WNA's ability to normalize revenues and customer bills around the weather assumptions embedded in base rates. Put differently, a 5% deadband would cause the WNA to respond less often and less completely when actual weather deviates from normal, even though deviations in that range can still have meaningful effects on both customer bills and the Company's recovery of authorized distribution revenues. In that respect, increasing the deadband is not merely a technical refinement; it is a substantive narrowing of the mechanism. If the Commission determines that a WNA remains appropriate for UGI Gas, then broadening the deadband in this manner would move the rider further away from effective weather normalization and closer to partial non-recognition of weather impacts.

[51] OCA St. 1, at pp. 36-37; I&E St. No. 3, at p. 16; CAUSE-PA St. No. 1, at p. 66.

Q. Do you have concerns about removing certain months from the WNA application, as proposed by OCA and CAUSE-PA,[52] given the characteristics of the Company's service territory?

A. Yes. The Company's service territory spans portions of Pennsylvania, including areas in the north and northwest of the Commonwealth where temperatures during the October through April period generally remain colder and space-heating requirements continue to be meaningful during the so-called "shoulder" months. As a result, customers in the Company's service territory may continue to experience weather-driven heating usage and bill variability during months such as October and April to a greater extent than customers in warmer regions of Pennsylvania. Because the WNA is intended to moderate the impacts of abnormal weather on both customer bills and the Company's recovery of authorized distribution revenues during periods when heating load remains material, removing October and/or April from the WNA application would reduce customer protections during months when customers still face meaningful weather-related bill volatility. In my view, applying a uniform statewide assumption regarding "shoulder" months without recognizing regional climatic differences and the Company's specific service territory characteristics would not appropriately reflect the Company's operating realities and could unnecessarily narrow the effectiveness of the WNA for the customers it is intended to protect.

Q. Does this conclude your testimony?

A. Yes.

[52] OCA St. 1, at p. 37; OSBA St. No. 1, at p. 65.

Comparison of Revenue Increase by Class Among Parties

Rate Classes	UGI Gas	OCA	OSBA	Average OCA & OSBA
Rate R	75.15%	69.95%	75.15%	**72.55%**
Rate N	23.53%	22.07%	23.53%	**22.80%**
Rate DS	0.71%	0.00%	0.57%	**0.29%**
Rate LFD	0.74%	7.98%	0.74%	**4.36%**
Rate XD Firm	-0.06%	0.00%	0.00%	**0.00%**
Rate IS	-0.07%	0.00%	0.00%	**0.00%**
Total	100.00%	100.00%	100.00%	**100.00%**

	Scale		1000000
		Total Residential And Commercial Revenue - 15-YR WNA	**Total Residential And Commercial Revenue - 10-YR WNA**
	Nov-22	$1.54	$0.85
	Dec-22	$1.02	-$0.46
	Jan-23	$6.15	$3.35
	Feb-23	$11.00	$6.64
	Mar-23	$9.19	$3.92
	Apr-23	$4.31	$2.44
	May-23	$0.49	$0.00
	2022-2023 Heating Season	$33.70	$16.75
	Oct-23	$0.26	-$0.39
	Nov-23	$1.28	-$0.31
	Dec-23	$2.27	$0.89
	Jan-24	$8.17	$4.38
	Feb-24	$9.08	$4.72
	Mar-24	$11.85	$6.24
	Apr-24	$4.91	$1.99
	May-24	$2.92	$2.92
	2023-2024 Heating Season	$40.72	$20.44
	Oct-24	$0.80	$0.78
	Nov-24	$3.97	$2.31
	Dec-24	$1.39	-$0.60
	Jan-25	-$1.43	-$5.17
	Feb-25	-$1.51	-$5.37
	Mar-25	$4.41	$0.85
	Apr-25	$5.75	$2.81
	May-25	$2.95	$3.40
	2024-2025 Heating Season	$16.31	-$1.00
	Oct-25	$0.37	-$0.23
	Nov-25	-$1.38	-$2.63
	Dec-25	-$6.57	-$9.31
	Jan-26	-$5.58	-$7.66
	Feb-26	-$14.44	-$17.25
	Mar-26	$0.30	$1.02
	2024-2025 Heating Season	-$27.30	-$36.05
Total		$63.44	$0.13

UGI WNA Adjustment Estimates (Simulation with Actual WNA results for November 2022-May 2025)

					Residentia 2005-2019 Normal 15-YR WNA Adjustment (CCF)
				Billed CCF	
Heating Season 2022-2023					
Oct	2022	10	10/1/2022		
Nov	2022	11	11/1/2022	31,057,239	2,153,568
Dec	2022	12	12/1/2022	70,380,622	1,439,549
Jan	2023	1	1/1/2023	86,208,908	8,647,924
Feb	2023	2	2/1/2023	72,656,807	15,124,980
Mar	2023	3	3/1/2023	75,097,831	12,723,261
Apr	2023	4	4/1/2023	41,532,085	6,098,146
May	2023	5	5/1/2023	24,774,811	566,866
Heating Season 2022-2023 Total				401,708,303	46,754,294
Heating Season 2023-2024					
Oct	2023	10	10/1/2023	14,335,446	324,373
Nov	2023	11	11/1/2023	33,514,084	1,828,070
Dec	2023	12	12/1/2023	64,363,308	3,242,561
Jan	2024	1	1/1/2024	86,032,554	10,942,912
Feb	2024	2	2/1/2024	78,991,209	12,481,667
Mar	2024	3	3/1/2024	62,467,686	16,251,546
Apr	2024	4	4/1/2024	51,117,877	6,519,900
May	2024	5	5/1/2024	21,456,077	4,057,503
Heating Season 2023-2024 Total				412,278,241	55,648,532
Heating Season 2024-2025					
Oct	2024	10	10/1/2024	14,093,332	996,923
Nov	2024	11	11/1/2024	24,785,139	5,538,982
Dec	2024	12	12/1/2024	71,656,665	1,887,330
Jan	2025	1	1/1/2025	104,776,286	(1,812,212)
Feb	2025	2	2/1/2025	98,013,733	(1,975,349)
Mar	2025	3	3/1/2025	77,602,738	6,060,757
Apr	2025	4	4/1/2025	44,547,790	7,757,939
May	2025	5	5/1/2025	21,134,822	4,018,315
Heating Season 2024-2025 Total				456,610,505	22,472,685
Heating Season 2025-2026					
Oct	2025	10	10/1/2025	13,516,959	497,914

Nov	2025	11	11/1/2025	32,488,785	(1,794,059)
Dec	2025	12	12/1/2025	83,320,267	(7,464,057)
Jan	2026	1	1/1/2026	105,247,535	(6,092,655)
Feb	2026	2	2/1/2026	109,421,410	(16,239,557)
Mar	2026	3	3/1/2026	78,864,943	-
Apr	2026	4	4/1/2026	-	-
May	2026	5	5/1/2026	-	-
Heating Season 2025-2026 Total				422,859,899	(31,092,414)

Source: Attachment OSBA-I-7

al Usage			Commercial Usage		
2010-2024 Normal	2015-2024 Normal		2005-2019 Normal	2010-2024 Normal	2015-2024 Normal
15-YR WNA Adjustment (CCF)	10-YR WNA Adjusment (CCF)	Billed CCF	15-YR WNA Adjustment (CCF)	15-YR WNA Adjustment (CCF)	10-YR WNA Adjusment (CCF)
2,598,320	1,161,605	18,576,916	1,195,604	1,466,026	700,069
295,974	(533,280)	41,089,898	806,552	(35,250)	(515,612)
6,176,356	4,273,718	49,530,311	4,805,902	4,343,761	3,198,935
11,813,440	9,502,352	38,914,725	9,143,287	6,241,509	5,038,485
7,133,488	5,696,255	44,551,400	7,756,586	3,694,493	2,931,595
3,647,971	3,478,132	22,230,590	3,325,206	1,947,575	1,848,394
14,296	(30,153)	15,398,262	538,818	60,195	48,974
31,679,843	23,548,629	230,292,102	27,571,954	17,718,308	13,250,840
(112,899)	(541,133)	11,174,159	244,467	12,623	(306,896)
330,297	(435,895)	20,207,335	872,105	190,114	(223,368)
1,865,017	1,114,116	36,056,091	1,533,232	1,264,767	813,207
8,455,471	6,043,011	51,020,933	6,520,991	4,656,505	3,271,631
8,936,361	6,501,329	43,877,584	6,817,989	4,837,261	3,525,345
10,179,719	8,714,703	34,619,118	8,949,897	5,253,213	4,507,365
2,681,401	2,568,603	29,787,058	3,989,020	1,822,976	1,718,314
3,895,818	3,821,279	13,590,068	2,129,677	2,452,017	2,453,272
36,231,186	27,786,013	240,332,346	31,057,376	20,489,477	15,758,869
1,348,727	870,905	11,137,387	726,400	1,303,895	851,675
4,306,842	3,077,082	14,967,697	2,866,276	2,516,299	1,873,363
132,897	(654,721)	41,916,169	1,070,197	(191,777)	(690,381)
(4,258,527)	(6,773,832)	62,055,544	(1,287,987)	(2,865,194)	(4,343,900)
(4,924,725)	(7,568,206)	54,836,524	(1,280,152)	(2,347,674)	(3,786,874)
2,258,470	1,003,355	44,017,311	3,305,453	1,517,215	852,639
3,946,205	3,879,234	25,268,997	4,519,651	2,142,624	2,080,851
4,801,083	4,732,785	14,028,859	2,268,074	2,494,043	2,472,522
7,610,973	(1,433,399)	268,228,488	12,187,912	4,569,430	(690,105)
(53,725)	(274,799)	10,976,625	305,796	(37,637)	(224,421)

(2,088,679)	(3,367,408)	18,951,028	(822,089)	(959,659)	(1,618,639)
(9,177,887)	(10,514,779)	49,319,029	(4,296,138)	(5,387,464)	(6,166,368)
(6,308,664)	(8,729,347)	60,447,418	(4,006,609)	(3,585,293)	(4,962,545)
(17,383,148)	(20,001,324)	60,423,148	(9,670,225)	(9,228,183)	(10,659,682)
2,544,704	1,166,299	49,745,263	-	1,492,975	652,107
-	-	-	-	-	-
-	-	-	-	-	-
(32,467,398)	(41,721,359)	249,862,511	(18,489,265)	(17,705,261)	(22,979,548)

Effective Rate	Billed Variable Revenue	Residential Variable Revenue 2005-2019 Normal 15-YR WNA Adjustment (Variable Revenue)	2010-2024 Normal 15-YR WNA Adjustment (Variable Revenue)	2015-2024 Normal 10-YR WNA Adjusment (Variable Revenue)	Effective Rate
0.50	$ 15,586,805	$ 1,080,819	$ 1,304,028	$ 582,979	$ 0.38
0.50	$ 35,030,509	$ 716,506	$ 147,315	$ (265,429)	$ 0.38
0.50	$ 43,205,828	$ 4,334,131	$ 3,095,441	$ 2,141,885	$ 0.38
0.50	$ 36,234,975	$ 7,543,041	$ 5,891,529	$ 4,738,957	$ 0.38
0.50	$ 37,298,070	$ 6,319,132	$ 3,542,916	$ 2,829,100	$ 0.37
0.50	$ 20,771,700	$ 3,049,904	$ 1,824,482	$ 1,739,540	$ 0.38
0.50	$ 12,389,697	$ 283,485	$ 7,149	$ (15,079)	$ 0.38
	$ 200,517,583	$ 23,327,018	$ 15,812,860	$ 11,751,952	
0.51	$ 7,284,841	$ 164,836	$ (57,372)	$ (274,988)	$ 0.38
0.52	$ 17,349,235	$ 946,337	$ 170,985	$ (225,650)	$ 0.38
0.52	$ 33,324,347	$ 1,678,848	$ 965,620	$ 576,838	$ 0.38
0.52	$ 44,534,137	$ 5,664,520	$ 4,376,914	$ 3,128,121	$ 0.38
0.52	$ 40,889,614	$ 6,461,106	$ 4,625,887	$ 3,365,398	$ 0.38
0.52	$ 32,336,153	$ 8,412,549	$ 5,269,491	$ 4,511,132	$ 0.38
0.52	$ 26,462,377	$ 3,375,181	$ 1,388,090	$ 1,329,698	$ 0.38
0.52	$ 11,108,724	$ 2,100,742	$ 2,017,031	$ 1,978,439	$ 0.38
	$ 213,289,429	$ 28,804,119	$ 18,756,647	$ 14,388,989	
0.52	$ 7,297,916	$ 516,234	$ 698,408	$ 450,978	$ 0.38
0.52	$ 12,834,048	$ 2,868,153	$ 2,230,135	$ 1,593,350	$ 0.38
0.52	$ 37,128,729	$ 977,916	$ 68,860	$ (339,242)	$ 0.38
0.52	$ 54,199,985	$ (937,443)	$ (2,202,904)	$ (3,504,052)	$ 0.38
0.52	$ 50,721,578	$ (1,022,233)	$ (2,548,519)	$ (3,916,506)	$ 0.38
0.52	$ 40,175,859	$ 3,137,726	$ 1,169,237	$ 519,449	$ 0.38
0.52	$ 23,061,602	$ 4,016,147	$ 2,042,880	$ 2,008,211	$ 0.38
0.52	$ 10,941,319	$ 2,080,248	$ 2,485,480	$ 2,450,123	$ 0.38
	$ 236,361,035	$ 11,636,747	$ 3,943,579	$ (737,689)	
0.52	$ 6,988,282	$ 257,422	$ (27,776)	$ (142,072)	$ 0.38

0.58	$ 18,949,230	$ (1,046,393)	$ (1,218,232)	$ (1,964,056)	$ 0.41
0.63	$ 52,736,649	$ (4,724,293)	$ (5,809,043)	$ (6,655,214)	$ 0.43
0.63	$ 66,637,983	$ (3,857,594)	$ (3,994,361)	$ (5,527,028)	$ 0.43
0.63	$ 69,278,840	$ (10,281,879)	$ (11,005,929)	$ (12,663,596)	$ 0.43
0.63	$ 49,932,383	$ -	$ 1,611,149	$ 738,428	$ 0.43
0.00	$ -	$ -	$ -	$ -	$ -
0.00	$ -	$ -	$ -	$ -	$ -
	$ 264,523,366	$ (19,652,737)	$ (20,444,192)	$ (26,213,538)	

	Commercial Variable Revenue		
Billed Variable Revenue	2005-2019 Normal 15-YR WNA Adjustment (Variable Revenue)	2010-2024 Normal 15-YR WNA Adjustment (Variable Revenue)	2015-2024 Normal 10-YR WNA Adjusment (Variable Revenue)
$ 7,074,935	$ 455,340	$ 558,330	$ 266,618
$ 15,521,858	$ 304,678	$ (13,316)	$ (194,774)
$ 18,740,536	$ 1,818,385	$ 1,643,527	$ 1,210,365
$ 14,710,417	$ 3,456,316	$ 2,359,395	$ 1,904,631
$ 16,517,043	$ 2,875,687	$ 1,369,701	$ 1,086,863
$ 8,436,272	$ 1,261,880	$ 739,084	$ 701,446
$ 5,842,876	$ 204,455	$ 22,841	$ 18,583
$ 86,843,937	$ 10,376,740	$ 6,679,561	$ 4,993,733
$ 4,274,573	$ 93,519	$ 4,829	$ (117,400)
$ 7,754,367	$ 334,662	$ 72,954	$ (85,715)
$ 13,837,813	$ 588,432	$ 485,400	$ 312,097
$ 19,580,895	$ 2,502,636	$ 1,787,081	$ 1,255,592
$ 16,839,130	$ 2,616,575	$ 1,856,421	$ 1,352,940
$ 13,286,124	$ 3,434,791	$ 2,016,078	$ 1,729,836
$ 11,431,667	$ 1,530,905	$ 699,621	$ 659,454
$ 5,215,556	$ 817,321	$ 941,028	$ 941,509
$ 92,220,126	$ 11,918,841	$ 7,863,412	$ 6,048,313
$ 4,274,212	$ 278,772	$ 500,398	$ 326,848
$ 5,744,269	$ 1,100,013	$ 965,700	$ 718,955
$ 16,087,494	$ 410,743	$ (73,604)	$ (264,969)
$ 23,816,779	$ (494,327)	$ (1,099,655)	$ (1,667,179)
$ 21,045,385	$ (491,302)	$ (901,000)	$ (1,453,342)
$ 16,892,995	$ 1,268,569	$ 582,278	$ 327,226
$ 9,697,739	$ 1,734,552	$ 822,296	$ 798,589
$ 5,384,008	$ 870,443	$ 957,166	$ 948,907
$ 102,942,881	$ 4,677,464	$ 1,753,578	$ (264,964)
$ 4,202,626	$ 117,080	$ (14,410)	$ (85,924)

$ 7,786,285	$ (337,766)	$ (394,289)	$ (665,040)
$ 21,208,503	$ (1,847,454)	$ (2,316,754)	$ (2,651,703)
$ 25,993,745	$ (1,722,932)	$ (1,541,756)	$ (2,134,005)
$ 25,983,726	$ (4,158,480)	$ (3,968,390)	$ (4,583,976)
$ 21,391,923	$ -	$ 642,023	$ 280,425
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
$ 106,566,807	$ (7,949,553)	$ (7,593,575)	$ (9,840,224)

	Residential	Commercial
10/1/2022	$ 0.50	0.38
11/1/2022	$ 0.50	0.38
12/1/2022	$ 0.50	0.38
1/1/2023	$ 0.50	0.38
2/1/2023	$ 0.50	0.38
3/1/2023	$ 0.50	0.37
4/1/2023	$ 0.50	0.38
5/1/2023	$ 0.50	0.38
6/1/2023	$ 0.50	0.38
7/1/2023	$ 0.52	0.36
8/1/2023	$ 0.26	0.38
9/1/2023	$ 0.50	0.38
10/1/2023	$ 0.51	0.38
11/1/2023	$ 0.52	0.38
12/1/2023	$ 0.52	0.38
1/1/2024	$ 0.52	0.38
2/1/2024	$ 0.52	0.38
3/1/2024	$ 0.52	0.38
4/1/2024	$ 0.52	0.38
5/1/2024	$ 0.52	0.38
6/1/2024	$ 0.52	0.38
7/1/2024	$ 0.53	0.38
8/1/2024	$ 0.52	0.39
9/1/2024	$ 0.51	0.38
10/1/2024	$ 0.52	0.38
11/1/2024	$ 0.52	0.38
12/1/2024	$ 0.52	0.38
1/1/2025	$ 0.52	0.38
2/1/2025	$ 0.52	0.38
3/1/2025	$ 0.52	0.38
4/1/2025	$ 0.52	0.38
5/1/2025	$ 0.52	0.38
6/1/2025	$ 0.56	0.38
7/1/2025	$ 0.48	0.32
8/1/2025	$ 0.46	0.38
9/1/2025	$ 0.52	0.17
10/1/2025	$ 0.52	0.38
11/1/2025	$ 0.58	0.41
12/1/2025	$ 0.63	0.43
1/1/2026	$ 0.63	0.43
2/1/2026	$ 0.63	0.43
3/1/2026	$ 0.63	0.43

Source: Attachment OCA-8-50.xlsx

Year	Disputes	PUC Informal	PUC Formal
2022	7	2	None
2023	153	63	10
2024	31	22	2
2025	9	10	2
2026	None	None	None

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 12-R

Rebuttal Testimony of
Brian J. Meilinger

Topics Addressed: **Low Income Issues**
2025 Rate Case Settlement Compliance

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian J. Meilinger. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 12, on January 28, 2026.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to certain portions of the direct testimony submitted by Office of Consumer Advocate ("OCA") Witness Roger Colton (OCA St. 6), and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Witness Patrick Cicero (CAUSE-PA St. No. 1). In particular, my rebuttal testimony will address allegations and recommendations concerning the Company's support of its low income customers through its Universal Service and Energy Conservation Plan ("USECP"), as well as compliance with its 2025 Rate Case settlement.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits BJM-1R through BJM-25R. I note that UGI Gas Exhibits BJM-14R and BJM-22R are CONFIDENTIAL exhibits.

II. RESPONSE TO OTHER PARTIES' DIRECT TESTIMONY

A. AFFORDABILITY

Q. Do any of the other parties raise concerns about the impacts of the Company's proposed base rate increase on the affordability of service, in particular with respect to low-income customers?

A. Yes, OCA Witness Colton and CAUSE-PA Witness Cicero raise such concerns.

Q. Do you agree that UGI Gas bills are consistently unaffordable to low income customers?

A. No. While I do not dispute the income data cited by Witness Colton (OCA St. No. 6, at pp. 11-13), or the Asset Limited, Income Constrained, Employed ("ALICE") figures cited by Witness Colton (OCA St. No. 6, at pp. 17-22), I believe that the Company's Universal Service Programs are well-designed and have been successfully assisting low-income customers, resulting in positive affordability outcomes for many participants. Moreover, these programs are currently under review and will be subject to a number of changes and improvements that will further assist payment troubled customers in maintaining their utility service. UGI Gas filed its 2026-2030 USECP at Docket Nos. M-2025-3054362 and M-2025-3054366 on April 1, 2025. As a part of that filing, the Company proposed to update its USECP to include, among other things, the commitments below:

- UGI Gas increased the Low Income Usage Reduction Program ("LIURP") per job customer maximum from $8,000 to $10,000. In addition, customers in need of furnace or boiler replacement are eligible for up to $14,000 per job.
- Operation Share and LIURP budget flexibility will be enhanced to meet customer demand by Rate District by removing the 5% limitation on annual budget reallocations across the Company's geographic footprint of its former three rate districts.

- The Company clarified and confirmed that customers participating in the Company's Customer Assistance Program ("CAP") are eligible to receive Operation Share grants.
- The Company clarified and confirmed that Operation Share grants can be used to pay for restoration and reconnection fees.
- UGI Gas will participate in the Pennsylvania Department of Human Services ("DHS") data sharing process to promote the availability of its USECP programs.

Based upon these updates, it is clear that UGI Gas is working to consistently improve its Universal Service Programs, in order to ensure that payment troubled customers are provided with the necessary assistance to maintain utility service.

Furthermore, as part of the 2025 Gas Base Rate Case settlement (Docket No. R-2024-3052716), the Company has implemented several noteworthy customer service enhancements to help address affordability. These include the following:

- Increased the LIURP budget by $1,000,000 or approximately 24%, from $4,214,350 in calendar year 2025 to $5,214,350 in calendar year 2026.
- Increased the Company's Operation Share contribution by $500,000, or approximately 86% from $584,500 in Fiscal Year 2025 to $1,084,500 in Fiscal Year 2026.
- Launched the Low Income Customer Assessment and Outreach Pilot in March 2026 to assess, identify, and engage estimated low income customers for enrollment in the Company's CAP.
- Facilitated additional Winter Assistance Relief Mobilization ("WARM") events in various locations throughout the service territory to assist customers with direct enrollment into CAP.
- Waived the $73 reconnection fee for verified low-income customers.

- Updated its gas service tariff to reiterate security deposit exemptions for verified low-income customers.
- Eliminated transaction costs for cash payments made at authorized retail establishments.
- Revised dunning notices and credit call center scripts to include enhanced messaging regarding CAP.
- Waived the income documentation requirement for applicants to the Company's Universal Service Programs for those that received LIHEAP in the current or prior season or have participated in the DHS data sharing process.
- Waived the CAP recertification requirements for customers that received LIHEAP in the current or prior season or have participated in the DHS data sharing process.

Q. Has UGI Gas undertaken any additional voluntary efforts to support its low-income customers?

A. Yes. The Company has taken many voluntary efforts over many years. For one recent example, in November 2025, to help mitigate the impacts to low-income customers due to LIHEAP funding delays resulting from the Federal Government shutdown, the Company made a one-time supplemental donation of $500,000, allocated between the Gas and Electric Divisions, to Operation Share for Fiscal Year 2026. A fulsome discussion of the many voluntary actions the Company took in November 2025 was included with my direct testimony at pages 10-11.

Q. Are there other programs available to assist payment-troubled customers?

A. Yes. In addition to the UGI Gas Universal Service Programs, there are external programs to support payment-troubled customers. These state and federally funded programs include, but are not limited to LIHEAP, which provides energy grants which help customers restore and/or maintain service as well as repair or replace broken heating equipment, and the Pennsylvania Weatherization Assistance Program ("WAP") which reduces energy costs and increases comfort while ensuring homes are healthier and safer. Both of these programs were discussed in greater detail in my direct testimony. UGI Gas St. No. 12, at pp. 9-10.

In addition to these benefits that target heating and utility customers for specific benefits to address heating bills, there are other programs such as Temporary Assistance for Needy Families ("TANF") and Supplemental Nutrition Assistance Program ("SNAP") available to households to help offset the costs of basic needs such as food, which are asserted by OCA and CAUSE-PA to put strain on household budgets. Similar programs like the Children's Health Insurance Program ("CHIP") and Affordable Care Act to offset costs of healthcare are also available. As described by Witness Fang, UGI Gas Statement No. 16-R, individual utility rate cases are not the appropriate forum to address these macroeconomic and society-wide affordability concerns identified by OCA and CAUSE-PA.

Q. How is UGI Gas further addressing affordability concerns for its customers?

A. In recognition of the importance of supporting affordability of utility bills, UGI Gas will contribute $1,000,000 annually to Operation Share in Fiscal Years 2027, 2028, and 2029. This multi-year commitment is unprecedented in the Company's history and will provide

substantial assistance to low and moderate income customers with income levels up to 250% Federal Poverty Level ("FPL"). The Company anticipates this funding will provide approximately 2,770 grants per year, based on an assumed average grant of $360, which is consistent with the average grant for the prior three years of Operation Share.

Q. Does OCA Witness Colton identify a different population of customers in UGI Gas's service territory, that he claims UGI Gas and the Commission should consider?

A. Yes. He claims that UGI Gas needs to examine ALICE customers in its territory.

Q. How do you respond to Witness Colton's testimony regarding the use of ALICE data to examine affordability and the impacts of the Company's base rate increase?

A. Although I do not dispute the ALICE data presented, I disagree that it is appropriate to use this data to analyze the impacts of the Company's rate case and/or its Universal Service Programs. The FPL guidelines are the standard indicator of a customer's income status and are used as such by the Commission and the Company. The FPL guidelines have also been used as a verification process to enroll customers into the Company's USECP. Witness Colton's recommendation to analyze ALICE data would be better suited outside of a rate case proceeding where various stakeholders, including the Commission and other community partners, would have the opportunity to provide input on his recommendations and consider the impacts of those recommendations. A base rate case, which involves a host of other issues and is on an expedited time frame for resolution, is simply not the appropriate time to consider such a recommendation.

Q. Do you agree with Witness Colton's claim that UGI Gas needs to better market its customer assistance programs and budget billing to payment-troubled customers?

A. No. The Company has demonstrated a concerted focus on continued marketing and customer outreach to increase CAP enrollment, which will help minimize the impact of rate increases as customers on the CAP Percent of Income Payment Plan ("PIPP") and minimum bill are not impacted. UGI Gas has only about 27% of its CAP customers on average bill (i.e., CAP participants that are likely to experience some increase based on the outcome of this proceeding). *See* UGI Gas Exhibit BJM-1R (UGI Gas response to CAUSE-PA-1-1).

Regarding UGI Gas's activities, I want to note the following. First, the Company has continued its Low Income Customer Assessment and Outreach Pilot to assess, identify, and engage estimated low income customers through various marketing channels with a goal to increase enrollment into CAP. This campaign launched on March 3, 2026, with approximately 45,000 customers receiving direct mail and approximately 67,000 receiving email. *See* UGI Gas Exhibit BJM-2R (UGI Gas response to CAUSE-PA-8-1). As of May 06, 2026, 718 customers have already been enrolled in CAP as a result of this pilot.

Second, the Company continues its marketing efforts via general outreach throughout the year, as well as semiannual, personalized marketing to customers who are self-certified low income but have not income verified in order to enroll in CAP, and to LIHEAP recipients that are not currently enrolled in CAP. *See* UGI Gas Exhibits BJM-3R and BJM-4R.

Third, the Company recently began utilizing information from the DHS data sharing process to identify customers that received LIHEAP, but were not yet enrolled in

CAP and have utilized this information to solicit these customers via email or direct mail for enrollment into CAP.

Fourth, the Company has developed a comprehensive Consumer Education and Outreach Plan ("CEOP") that was included with the 2026-2030 USECP filing and includes all the various marketing tactics being utilized to increase enrollment in not just CAP, but all Universal Service Programs. *See* UGI Gas Exhibit BJM-5R.

Q. CAUSE-PA Witness Cicero also discusses low-income customers and affordability. Have you reviewed his testimony?

A. Yes.

Q. What is your response to Witness Cicero's feedback on the self sufficiency standard?

A. Although I do not dispute the Self Sufficiency data presented, I disagree that it is appropriate to use this data to analyze the impacts of the Company's rate case and/or its Universal Service Programs. The FPL guidelines are the standard indicator of a customer's income status and are used as such by the Commission and the Company. The FPL guidelines have also been used as a verification process to enroll customers into the Company's USECP. Furthermore, when asked in discovery if Witness Cicero is proposing that the Commission adopt the Self Sufficiency standard instead of FPL, he indicated that he is not taking the position in this case that the Commission should change its eligibility criteria for universal service programs. *See* UGI Gas Exhibit BJM-6R (Response to UGI to CAUSE-PA-1-3.

Q. What is your response to Witness Cicero's feedback on the Company's estimated low income customer counts?

A. Witness Cicero specifically disagrees with my position on the PUC's methodology for estimating low-income customer population, arguing that "the Company now has information that reasonably places 90% of the households included in the Experian survey in the low income category," so "under the Commission's regulatory definitions, these households should be classified as **confirmed** low income households." CAUSE-PA St. No. 1, at pp. 23-24. He also disagrees that the PUC's ELI count is over inclusive. CAUSE-PA St. No. 1, at pp. 24-25. I continue to maintain that the census calculation methodology that is used to report this data to the Commission that was referenced in my direct testimony, UGI Gas St. No. 12, at p. 16, resulting in 143,404 estimated low income customers, may overstate estimated low-income customer counts. My reasoning for this is because the calculation simply assumes that census poverty level percentages by county apply equally to UGI's customers in those same counties. In reality, the census data does not account for the actual demographics of UGI Gas's customers. By comparison, the Company's Low Income Customer Assessment and Outreach Pilot undertaken with Experian, identified an estimated low-income population of 96,137 customers at or below 150% FPL in January 2026. *See* UGI Gas Exhibit BJM-7R (UGI Gas response to CAUSE-PA-6-17). The Experian estimate used actual demographic income data of UGI customers with a match rate of 90% on name and address, and identified significantly fewer customers, at only 67% of the estimated low income customer count of 143,404 that is reported to the Commission. Therefore, UGI Gas's estimated low-income customer counts

based on census and published in the Universal Service Programs & Collections Performance Report should be considered an over estimation and referenced with caution.

Q. What is your response to Witness Cicero's recommendation for the Company to update its Confirmed Low Income counts with Experian data?

A. I disagree with his recommendation. In accordance with Paragraph 67(a) of the 2025 UGI Gas Base Rate Case Settlement, the Company's definition of Confirmed Low Income is consistent with the Commission's definition at 52 Pa. Code §§ 62.2 and 69.262. Households that fit this criteria include:

- Self certification;
- Participation in any of the Company's income verified programs including but not limited to CAP, Operation Share, or LIURP, where income is verified to be at or below 150% FPL and/or
- Receipt of LIHEAP funds in the prior 12 months.

Witness Cicero appears to confuse estimated low income and confirmed low income, where doing so overinflates the number of confirmed low income customers that the Company must report. It is not appropriate for the Company to simply take data from a third party vendor and override records in its Customer Information System. For instance, it is unclear whether Witness Cicero is proposing that a customer who has self-certified and is included in the Company's confirmed low income counts but is not identified in Experian's data as low income, should be removed from the Company's records as a confirmed low income customer. Also, from my perspective, this is a policy issue that

would be best addressed on a Commonwealth-wide basis through Commission rulemaking, so that there is uniformity across the electric and natural gas utilities.

Q. Witness Cicero argues that LIHEAP will not mitigate the harm of the proposed rate increase on low-income households because it is not funded adequately enough to mitigate the impacts. CAUSE-PA St. No. 1, at pp. 32-33. If LIHEAP is available to low-income customers, will it mitigate the impacts of the Company's proposed rate increase?

A. Yes. Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly $32 million. This funding has been instrumental in assisting low-income customers in maintaining and/or restoring natural gas service as well as emergency furnace repair or replacement. Furthermore, even though the 2025-2026 LIHEAP season was delayed in opening by about one month, the Company has already facilitated $6.1 million in grants to nearly 19,000 customers as of mid-May. Witness Cicero also notes that, "[f]or the second year in a row, LIHEAP is proposed for elimination in the federal budget." CAUSE-PA St. No. 1, at p. 33. However, it is simply too far in advance to speculate on what may happen regarding the 2026-2027 LIHEAP budget, especially since the launch of the next season, anticipated to be November 1st, is approximately six months from now. Additionally, it is important to recognize that LIHEAP is not the only assistance available to UGI Gas's customers to reduce their electric bills. Thus, LIHEAP should not be viewed in isolation when determining whether its funding is sufficient to help mitigate the impacts of the proposed base rate increase.

Q. Do you agree with Witness Cicero's claims regarding the impact of the rate increase on CAP customers?

A. No. As mentioned above, the Company currently has approximately 27% of its CAP customers on average bill. The remaining 73% of its CAP customers are on either a PIPP or minimum bill and are, therefore, insulated from any rate increases.

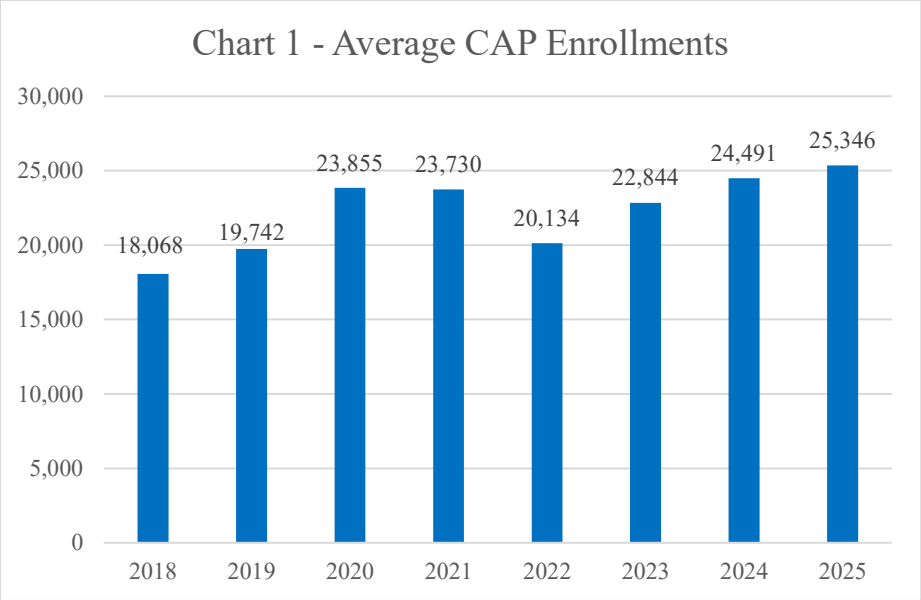
Regarding Witness Cicero's claim that CAP enrollment is insufficient relative to need (CAUSE-PA St. No. 1, at p. 17), it is worth reinforcing that CAP is a voluntary program and the Company cannot force customers to go through the income verification process and pursue enrollment in CAP. As discussed in my direct testimony (UGI Gas St. No. 12, at p. 15), as of November 2025, the Company had 68,867 confirmed low income customers, and approximately 26,000 were enrolled in CAP. However, similar to the approximate 40,000 confirmed low income customers cited by Witness Colton (OCA St. No. 6, at pp. 51-52), that were not enrolled in CAP, the Company's records indicate that approximately 30,000 of the 40,000 confirmed low income customers are self-certified low income and have not made an effort to provide the Company or its Community Based Organizations ("CBOs") with documentation in order to income verify, enroll in CAP, and receive the associated program benefits. Therefore, I take issue with Witness Cicero's claim that the program is "severely undersubscribed" (CAUSE-PA St. No. 1, at p. 32) as the population of income verified customers that are *not* enrolled in CAP is minimal.

Q. Does Witness Cicero make any claims about the Company's USECP?

A. Yes, he summarizes the programs run by UGI Gas and notes that UGI has not proposed any changes in this case. CAUSE-PA St. No. 1, at pp. 67-68. He summarizes the Company's CAP enrollment numbers and UGI's efforts to improve its enrollment numbers, asserting that such efforts have not been enough. CAUSE-PA St. No. 1, at pp. 68-72.

Q. Do you have any response to these claims?

A. Yes. I agree with Witness Cicero's assessment that UGI Gas has not proposed any changes to its USECP in this case. However, I take issue with his assessment that CAP enrollment numbers are not sufficient and more needs to be done. Witness Cicero references chart 3 on page 71 of his testimony. He used year 2020 as the baseline to evaluate CAP performance on a year over year basis. However, his chart is misleading and fails to acknowledge that he is selecting a baseline year, point in time number (December 2020) in which CAP enrollment was artificially inflated due to the economic impacts of COVID. A more accurate representation of historical CAP performance is provided in Chart 1 below which utilizes average CAP data, not point in time data that Witness Cicero appears to have used. This chart includes enrollment data prior to COVID, with 2018 as the baseline year. When comparing average CAP enrollment for 2025 to average CAP enrollment for 2018, there was a 40% increase during this timeframe. To analyze further, the Compound Annual Growth Rate (CAGR) for average CAP enrollment during the 2018 – 2025 timeframe was a respectable 4.95%. *See* UGI Gas Exhibit BJM-8R.



Q. What recommendations does Witness Cicero make about the Company's USECP?

A. He recommends, that UGI "implement routine screening of its applicants and customers to determine eligibility for CAP and other universal service programs" by: (1) screening "all new and moving customers for income level at the time their service is established and ask whether they would like information about income qualified programs that may reduce their rate"; (2) screening "existing customers for household income level on any non-emergency calls and inquire whether there have been any updates to household income information"; and (3) developing "a process for routine income screening through UGI's online account portal." CAUSE-PA St. No. 1, at pp. 72-73. He recommends that customers "identified as low income through these regular screening processes should be referred for enrollment in CAP and other universal service programs – as well as LIHEAP." CAUSE-PA St. No. 1, at p. 73. He states "[w]hile UGI customers should be able to opt out of providing household income information, they should first be informed that if they choose to disclose this information, they may be eligible for lower rates or energy

efficiency measures." CAUSE-PA St. No. 1, at p. 73. He recommends that UGI develop and implement "[the] screening and referral recommendations within 90 days of the PUC's Final Order in this proceeding." CAUSE-PA St. No. 1, at p. 73.

Q. Do you agree with these screening recommendations?

A. No. When asked in discovery what analysis Witness Cicero has prepared regarding a customer's willingness to share income, the potential customer dissatisfaction that may arise from an income screening process, and the costs associated with increased call handle times, he indicated that he had not performed any such analysis. *See* UGI Gas Exhibit BJM-9R (Response to UGI to CAUSE-PA-1-8) The Company believes that most customers will not want to share their income, and that average handle time for calls may increase as customers ask questions on why they are being solicited to provide their income. To better understand customer preferences, the Company recently surveyed a random sampling of 4,736 customers, with 355 customers completing the survey with a margin-of-error +/- 5% on their willingness to provide their income to a call center representative. The results indicated that only 31% of customers would be willing to share their income, 47% would not share their income, and 22% were not sure. *See* UGI Gas Exhibit BJM-10R. Therefore, given the likely low adoption, potential for customer dissatisfaction, and associated expenses to implement Witness Cicero's suggested income screening, this recommendation does not seem justified given that survey results suggest less than one-third of UGI Gas's customers would be willing to participate. The Company already requests income and occupancy during all inbound calls regarding past due notices and nonpayment service disconnections. This practice is designed to ascertain the caller's

eligibility for the Company's Universal Service Programs. If, based upon their stated income and household occupancy, the caller appears to be eligible for CAP, the caller is referred to a CBO and is solicited for enrollment. If the caller already had their income verified, enrollment into CAP is expedited and facilitated during the call.

Q. What recommendations does Witness Cicero make about the Company's USECP?

A. He recommends that "UGI prioritize scheduling additional future events, at a similar scale and frequency, in the other areas identified in [his] Table 13" besides Lancaster, Wilkes Barre, and Williamsport. CAUSE-PA St. No. 1, at pp. 74-75. He also recommends that UGI also target the Lebanon, Berwick, Pittston/West Pittston, and Sunbury areas for Universal Service Outreach. CAUSE-PA St. No. 1, at p. 75.

Q. Do you agree with these recommendations?

A. Yes. In accordance with Paragraph 61(b) of the 2025 UGI Gas Base Rate Case Settlement, the Company has already agreed to expand its WARM events to target a minimum of three new cities within its service territory as set forth in its tariff, which will be identified in consultation with its Universal Service Advisory Committee ("USAC"). In addition to the Lancaster, Williamsport, and Wilkes Barre locations identified for 2026, the Company has already facilitated eight different WARM events in locations such as Harrisburg, Allentown, Reading, and Lock Haven and has directly enrolled 241 customers into CAP year-to-date April 22, 2026. The Company anticipates completing at least 15 more WARM events at various locations within UGI Gas's service territory by calendar year-end.

Regarding Witness Cicero's recommendation to target the Lebanon, Berwick, Pittston/West Pittston, and Sunbury areas for Universal Service Outreach, I also agree with this recommendation. As part of the Low Income Customer Assessment and Outreach Pilot discussed above, these locations were already part of the marketing campaign that launched in early March. To date, approximately 4,200 customers in these locations have been part of the pilot and have received the Company's marketing materials promoting the availability of CAP and the benefits of enrollment.

Q. Does Witness Cicero make any claims about Operation Share?

A. Yes, he describes the Company's Operation Share Program along with the Company's proposed commitment to contribute $1 million annually for FY 2027 through FY 2029 to the fund. CAUSE-PA St. No. 1, at p. 76. He asserts that that while he "strongly support[s] UGI's proposal to contribute $1,000,000 annually to the Operation Share program, the Operation Share contribution will nonetheless be a reduction for years 2027 to 2029 compared to the 2026 budget." CAUSE-PA St. No. 1, at p. 76. He recommends that "UGI, **at a minimum**, continue its $1,584,500 total contributions to prevent a reduction in available funding for this vital program"; however, "if any rate increase is approved in this proceeding," he "believe[s] it would be appropriate for UGI to contribute additional funds over and above this $1.5 million to account for the additional hardships caused by the impact of such an increase." CAUSE-PA St. No. 1, at p. 77 (emphasis in original).

Q. Do you have a response to these claims and recommendations?

A. Yes, Witness Cicero's analysis is limited to what he presented in his direct testimony and he has not spoken with any of the Company's CBOs regarding if "it would be appropriate for UGI to contribute additional funds over and above this $1.5 million to account for the additional hardships caused by the impact of such an increase" and whether the CBOs believe that this funding would be utilized. CAUSE-PA St. No. 1, at p. 77.

B. IDENTIFICATION OF LOW INCOME CUSTOMERS

Q. OCA Witness Colton also presents testimony regarding UGI Gas's identification of low-income customers. Could you summarize that testimony?

A. Witness Colton claims that UGI Gas does a "poor job" of enrolling confirmed low-income customers into CAP and LIHEAP. OCA St. 6, at pp. 51-52. He claims that more than 7 of 10 disconnected customers that UGI Gas had a "reasonable belief" to be low-income were not enrolled in LIHEAP crisis and unfavorably compared LIHEAP enrollment to Supplemental Nutrition Assistant Program ("SNAP") enrollment. OCA St. 6, at p. 53. He made a number of recommendations, including (1) UGI Gas accept a printout or screenshot of a COMPASS application to establish confirmed low-income status, (2) that customers attempting to negotiate a DPA with the Company receive written, plain language notice of their rights to enroll in CAP and its advantages and disadvantages, as well as customers from whom the Company receives information placing them in an income tier of 0% to 150% FPL, UGI be required to require a Confirmed Low-Income customer to pay off arrears through a payment arrangement only with informed consent, and that UGI Gas be directed to provide its low-income advisory committee regular three month reports on the operation and effectiveness of its Low-Income Customer Assessment and Outreach Pilot. OCA St. 6, at pp. 54-58.

Q. Do you agree with Witness Colton's claim that UGI Gas does a poor job of enrolling customers in CAP and LIHEAP?

A. No. Witness Colton cites more than 40,000 confirmed low income customers that are not enrolled in CAP. OCA St. 6, at p. 51. He fails to acknowledge that many of these customers are self-certified and have not taken steps to income verify which would then make them eligible for enrollment in CAP. For example, Table 17 of OCA St. 6, p.52, Witness Colton referenced 42,561 confirmed low income customers in January 2026. Of these customers, nearly 30,000, or 70%, are self-certified and have not gone through the Company's income verification process and thus would not be eligible for enrollment in a Universal Service Program. The Company utilizes various marketing tactics throughout the year to promote its CAP. In particular, as discussed above, the Company does a twice a year marketing campaign focused on self-certified customers who are not enrolled in CAP. Therefore, the 30,000 customers referenced above receive messaging on the availability and benefits of CAP. UGI Gas should not be held accountable for customers that do not take the initiative to go through the income verification process and establish eligibility for program enrollment. When asked in discovery how many of the approximate 40,000 customers Witness Colton believes actually qualify for enrollment in CAP, have received the Company's marketing materials, have returned a completed application, and have been affirmatively denied for CAP because they did not qualify for participation in the program, he did not know the answer. *See* UGI Gas Exhibit BJM-11R (OCA Response to UGI-I-17). Furthermore, Witness Colton does not acknowledge that a contingent of this customer population may simply not want to enroll in CAP for whatever reason.

Regarding LIHEAP enrollment, Witness Colton references that only 24,682 customers out of 66,139 confirmed low income customers received LIHEAP in the 2024-2025 program year. OCA St. 6, at p. 52. However, Witness Colton does not take into consideration that many of the 41,457 (66,139 minus 24,682) confirmed low income customers that he claims were not enrolled in LIHEAP, may have received LIHEAP through their Electric Distribution Company and would therefore, not be eligible to receive LIHEAP for their UGI Gas account. In these cases, UGI Gas would not have information available to indicate if a customer received LIHEAP through PPL or First Energy, etc. Since the DHS data sharing process only provides utilities with information on their own customers, there is not enough information available for utilities to have a comprehensive assessment of which federal assistance programs, such as LIHEAP, a customer may have received from another utility provider. Furthermore, LIHEAP is a program that is administered by the DHS and is not solely the responsibility of the utility, as customers need to income verify and meet the specific program criteria that have been established, implemented, and managed by DHS. However, the Company does a twice a year marketing campaign focused on LIHEAP customers who are not enrolled in CAP, which provides them information on the availability and benefits of the program, and encourages them to take action to enroll in CAP.

In reference to Witness Colton's comparison to SNAP, in which he indicated that 2022 Pennsylvania participation rates exceeded "98% of SNAP-eligible low income households" (OCA St. No.6, at p. 53), the DHS is responsible for administering both SNAP and LIHEAP. Further, as Witness Colton's response to UGI Gas Set III, No. 1 suggests, SNAP's guidelines differ from CAP's guidelines and are not based solely on gross income

as a percentage of the Poverty Level. *See* Exhibit BJM-12R (OCA Response to UGI-III-1). Therefore, Witness Colton should not be holding a regulated utility, such as UGI Gas, solely accountable for participation rates in assistance programs that are administered by the Commonwealth of Pennsylvania.

Q. Do you agree with Witness Colton's recommendation that UGI Gas accept a printout or screenshot of a COMPASS application to establish confirmed low-income status?

A. No. As explained previously, the Company's definition of Confirmed Low Income is consistent with the Commission's definition in 52 Pa. Code §§ 62.2 and 69.262 which states that households that fit this criteria include those that:

- Self certify;
- Participate in any of the Company's income verified programs, including but not limited to CAP, Operation Share, or LIURP where income is verified to be at or below 150% FPL; and/or
- Have received LIHEAP funds in the prior 12 months.

Therefore, because a customer can simply self-certify their income, Witness Colton's recommendation to have a customer provide a screenshot of a COMPASS application to "establish confirmed low income status" is not needed and is unnecessarily complicated. However, for purposes of enrollment in the Company's Universal Service Programs, customers need to have their income verified.

Q. Do you agree with Witness Colton's recommendation that customers attempting to negotiate a Deferred Payment Arrangement ("DPA") with the Company receive written, plain language notice of their rights to enroll in CAP?

A. No. In response to discovery, Witness Colton has not provided any suggestions on sample content that he considers to be plain language. *See* UGI Gas Exhibit BJM-13R (Response of UGI to OCA-1-16). Furthermore, Witness Colton has not prepared any analysis on whether a DPA or CAP enrollment is more advantageous to the customer. He is simply making a blanket recommendation without consideration of case-by-case situations. In accordance with Paragraph 67(e) of the 2025 UGI Gas Base Rate Case Settlement, the Company has already reviewed with its USAC and updated its call center scripts for interactions regarding credit and collections interventions. *See* CONFIDENTIAL UGI Gas Exhibit BJM-14R. Therefore, the Company's call center representatives are already discussing the benefits of CAP enrollment with customers who inquire about a DPA, so there is no need to create a separate process to develop new plain language notices. Additionally, in accordance with Paragraph 67(c) of the 2025 UGI Gas Base Rate Case Settlement, the Company updated its dunning communications to further emphasize the option to enroll in CAP. These communications include language regarding CAP and the associated benefits of program enrollment. *See* Exhibit BJM-15R through UGI Gas Exhibit BJM-19R (UGI response to OCA-6-8.1 through OCA-6-8.5). Witness Colton is not taking into account the level of potential confusion that may arise if a customer is speaking with a call center representative about a DPA and they are then redirected to a conversation about CAP enrollment and a plain language letter that they will receive with further details

before being allowed to enter into a DPA. UGI Gas submits that its existing notices, policies, practices, and procedures are reasonable and do not need to be modified.

Q. Do you agree with Witness Colton's recommendation that UGI Gas be directed to provide its USAC with regular three-month reports on the operation and effectiveness of its Low-Income Customer Assessment and Outreach Pilot.

A. No. In accordance with Paragraph 61(a)(i) of the 2025 UGI Gas Base Rate Case Settlement, the Company provided its Low Income Customer Assessment and Outreach Pilot marketing plan to its USAC 30 days prior to the December 4, 2025, meeting. During the December meeting, the marketing plan was reviewed with attendees, written comments were provided by the USAC, and the Company provided written responses to the comments while incorporating suggestions where feasible. Furthermore, the Company agreed to facilitate quarterly USAC meetings in 2026; a frequency level not seen in the past. The Company intends to share updates on this pilot, including the number of customers enrolled in CAP at each of these meetings. Therefore, Witness Colton's request for the Company to share regular, three-month reports on the pilot is unnecessary.

Q. Do you have additional observations regarding Witness Colton's feedback on the Low Income Customer Assessment and Outreach Pilot?

A. Yes. Witness Colton claims that "UGI Gas did not explain how it determined that the 385 new CAP enrollees were 'as a result of this pilot.'" OCA St. 6, at p. 58. The Company utilized direct mail and email to drive customers to a vanity URL that was created specifically for this pilot and was therefore able to determine that the 385 new CAP

enrollments were associated with the Low Income Customer Assessment and Outreach Pilot. Witness Colton also claims that the Company "did not explain how it selected the 45,000 customers to receive postcards." OCA St. 6, at p. 58. However, the Company previously provided the rationale for how it determined the number of customers that would receive a direct mail postcard. *See* UGI Gas Exhibit BJM-20R (UGI response to OCA-6-5.1.) Furthermore, this information was reviewed at the Company's December 4, 2025, USAC meeting. Although Witness Colton was not in attendance, he acknowledged that OCA had representation at this meeting, but apparently, he did not review the meeting's presentation or discuss his questions with OCA colleagues. *See* UGI Gas Exhibit BJM-21R (Response to UGI to OCA-1-29.)

Q. **Could you summarize Witness Colton's testimony and recommendations regarding deposit exemptions?**

A. Yes. He claims UGI does not comply with the prohibition on requiring deposits from low-income customers. OCA St. 6, at p. 59-60. He also claims that, contrary to regulatory requirements, UGI does not return deposits to customers unless they have applied for CAP and had their income confirmed. OCA St. 6, at p. 59-62. He also expressed concern with the practice of returning deposits as credits on customer accounts. OCA St. 6, at p. 63. He recommends that (1) UGI be directed to modify its processes and procedure regarding the low-income exemption from deposits and that UGI should be directed to accept any information beyond information in income and household size that would attest to the household's eligibility for a state benefit that is consistent with CAP income requirements, (2) that UGI eliminate the requirement that a customer apply for CAP to establish eligibility

for deposit exemption, and (3) that within three months of a final order in this proceeding and for every three months thereafter, UGI undertake review of the cash security deposits it currently holds and report the results of such review to interested stakeholders in this proceeding. OCA St. 6, at p. 62-63.

Q. Does Witness Cicero also bring up the Company's policy regarding the collection and return of security deposits?

A. Yes.

Q. Could you describe that testimony?

A. Yes, he expresses concerns with this policy because: (1) a low-income household does not need to enroll in CAP or another universal service program for the prohibition on security deposits to apply; and (2) the imposition of a security deposit on low-income customers "can pose a significant barrier to low income customers who are already struggling to connect to and maintain service." CAUSE-PA St. No. 1, at pp. 84-85. He asserts that "it is not clear whether UGI requires the customer to actually enroll in CAP before returning the security deposit and it is unclear [whether UGI] applies returned deposits to the customer's account or allows the customer to determine whether the customer wants the security deposit refunded to them directly or whether they want it applied to their account." CAUSE-PA St. No. 1, at p. 86. He recommends that "UGI amend its tariff and all its internal processes so that customers who have been confirmed to be income eligible for CAP have their security deposit refunded to them regardless of whether they enroll in CAP or not." CAUSE-PA St. No. 1, at p. 86.

Q. Do you have a response to this testimony?

A. Yes. I believe it is worth clarifying the Company's processes regarding security deposit exemptions. First, customers are not required to enroll in CAP to receive the exemption. The Company has developed an income verification process by using the CAP application because it provides a consistent process for customers and CBOs, and if the customer decides they want to enroll in CAP after verifying their income, the process is seamless. For customers who have received LIHEAP in the current or prior season, they do not need to income verify as they have already been through that process with DHS and UGI Gas recognizes this as an acceptable form of verification. Therefore, the concerns raised by OCA and CAUSE-PA regarding exempting low income customers from the security deposit are without merit.

Second, regarding Witness Colton's recommendation to use a screenshot or printout of the COMPASS application as part of the income verification process, it is the Company's understanding, based on feedback from the DHS, that screenshots and/or printouts of the COMPASS application are not available to customers.

Third, Witness Colton has not clarified if the COMPASS application would demonstrate consistency with the Company's required documentation included in its USECP. Witness Colton's recommendation to use COMPASS applications would be better addressed outside of a rate case proceeding where various stakeholders, including the Commission and other community partners, would have the opportunity to provide input on his recommendations and consider the impacts of those recommendations.

Fourth, for customers receiving a refund of their security deposit, if they are enrolled in autopay, the deposit will be returned to the customer by direct debit. If the

customer is not enrolled in auto pay, then the deposit will be returned via check. *See* CONFIDENTIAL UGI Gas Exhibit BJM-22R (UGI response to OCA CONFIDENTIAL Attachment OCA-3-2.4). Regarding Witness Colton's recommendation that within three months of a final order in this proceeding and for every three months thereafter, UGI undertake review of the cash security deposits it currently holds and report the results of such review to interested stakeholders in this proceeding (OCA St. 6, at p. 62), this recommendation is not supported by any analysis as to why it is necessary to pursue a review of cash security deposits. The Company has already implemented IT systems processes to automatically release a security deposit once a customer has gone through the income verification process. *See* UGI Gas Exhibits BJM-23R and BJM-24R (UGI response to CAUSE-PA-6-1 and CAUSE-PA-6-2).

C. 2025 UGI RATE CASE SETTLEMENT

Q. Witness Colton raises some concerns about UGI Gas's compliance with the 2025 Rate Case Settlement. Could you summarize his concerns?

A. Yes, he makes several observations. While he does not accuse UGI Gas of failing to comply with the settlement, his concerns support the conclusion that there has not been sufficient time to determine whether UGI is complying. OCA St. 6, at p. 78. Notably, he acknowledges several areas where UGI is complying, particularly with regard to: the LIURP budget and using LIHEAP data to recertify CAP customers; that UGI is now using the PUC Common application form for CAP enrollment; and that UGI has increased Operation Share funding by $500,000. OCA St. 6, at pp. 78-79. He also comments that it is simply too early to assess the Company's compliance with the outreach and public engagement aspects of the 2025 settlement OCA St. 6, at p. 79. He also notes that per

household grants have declined and that CAP enrollment is not rising. OCA St. 6, at pp. 79-80.

Q. Do you have a response to these claims?

A. Yes. As noted by Witness Colton, the Company has successfully implemented the majority of the 2025 UGI Gas Rate Case Settlement initiatives. Although he comments that it is simply too early to assess the outreach and public engagement settlement commitments, the Company has established the foundation for these initiatives to be successfully completed as agreed to in settlement. For instance, the Low Income Customer Assessment and Outreach Pilot launched in March and will continue for three years, additional WARM events are underway in Lancaster, Williamsport, and Wilkes Barre as agreed to in settlement, and the Company has engaged with all of the Mayor's Offices identified in settlement by providing copies of the Universal Service Programs brochures in English and Spanish.

Regarding Witness Colton's comment about a declining average per household Operation Share grant amount during November 2025-January 2026 (OCA St. 6, at p.79), his analysis is too narrow since this timeframe included the Company's efforts to offset the delay in LIHEAP launching due to the federal government shutdown. In November, the Company made a $500,000 supplemental Operation Share contribution to support customers in need. During the November 2025-January 2026 timeframe, 3,125 grants ($862,136) were issued which was 544% higher than the prior year same time period. Because of the volume of grants, the average per household Operation Share grant was slightly lower than prior years. However, a more effective way to view average Operation

Share grants would be to view the entire year, rather than comparing to only a three-month time period as Witness Colton did. This trend can be seen in the UGI response to CAUSE-PA-2-17(A), which indicates average grants per household for 2025 were consistent with 2024 and 2023. *See* UGI Gas Exhibit BJM-25R.

In terms of Witness Colton's comments on CAP enrollment not increasing, (*see* OCA St. 6, at p. 80) similar to my commentary above on average Operation Share grants per household, his analysis is far too narrow and should not be given much consideration. Witness Colton is isolating his analysis to only a four-month period (October-January) but should instead be evaluating performance based on average CAP enrollment throughout the year which accounts for fluctuations in enrollment to capture new enrollees, and those who chose to leave the program. As discussed earlier in my testimony, Chart 1 above more accurately demonstrates the Company's historical CAP performance and reflects a 40% growth in enrollment when comparing 2025 average enrollment vs. 2018 average enrollment, with a respectable 4.95% CAGR during this time period.

For a comprehensive list of all customer service-related 2025 UGI Gas Base Rate Case settlement initiatives that have been completed, or are currently underway, please reference UGI Gas Statement No. 13-R, the rebuttal testimony of UGI Gas Witness Daniel V. Adamo.

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit BJM-1R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 1 (1-25)
Delivered on March 19, 2026

CAUSE-PA-1-1

Request:

Please identify the financial impact of the proposed increase on customers enrolled in UGI Gas's Customer Assistance Program (CAP) by payment plan type. If you are unable to identify the financial impact, or assert that there will be no impact, please explain.

Response:

The Company's CAP participants pay a monthly CAP amount based on a percent of income, or, if the percent of income payment is greater than their average bill, the CAP participant pays a monthly CAP amount equal to their average bill. Notwithstanding the foregoing, a CAP Customer's minimum monthly payment is set at a floor of $25 for heating accounts and $15 for non-heating accounts. A CAP participant's monthly payment is fixed until the participant recertifies income (at which time it is determined whether the monthly payment amount should change). The Company's proposed rate increase will not impact CAP payments set at a percent of income or a minimum payment. However, as of the date of this response, approximately 27% of UGI CAP customers have their CAP payment set at their average monthly bill. Upon income re-certification, these average monthly bill CAP payments could be impacted in an amount up to the approved rate increase. Also, no CAP Customer would pay more than their applicable percentage of income calculation, set forth in the Company's USECP.

Prepared by or under the supervision of: Brian J. Meilinger

UGI Gas Exhibit BJM-2R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 8 (1-7)
Delivered on April 9, 2026

CAUSE-PA-8-1

Request:

Please provide the details on the current status of UGI's Low Income Customer Assessment and Outreach Pilot? If there are interim or final findings, conclusions, or lessons learned as a result of this pilot please describe them in detail. Please provide any training and outreach materials utilized in implementing the pilot.

Response:

UGI Gas launched the Low Income Customer Assessment and Outreach Pilot on March 3, 2026. The Company utilized email and direct mail campaigns, which included 2 postcards mailed to approximately 45,000 customers and 3 emails sent to approximately 67,000 customers. Additionally, the Company initiated paid search and social media advertising. As of April 2, 2026, 385 customers have enrolled in CAP as a result of this pilot.

Prepared by or under the supervision of: Brian J. Meilinger

UGI Gas Exhibit BJM-3R

Energy to do more®

May 4, 2026

{Customer Name}
{Customer Mailing Address}
{Mailing City State ZIP}

Dear {Customer Name},

Based on information you previously provided to us, you may qualify for enrollment in the UGI Customer Assistance Program (CAP) for account {Account Number} . Enrollment in the CAP Program will assist you in managing your monthly energy bill, is free and has no impact on your credit score.

You are eligible for enrollment in CAP if your income is at or below the income guidelines shown below. If you are eligible and interested in enrolling in the UGI Customer Assistance Program, please complete the attached Pennsylvania Utility Assistance Application Form, and return it with proof of income to: {CBO Name}, {CBO Address}.

Customer Assistance Program (CAP) Income Guidelines 2026

Household Members	Annual Income	Monthly Income	Weekly Income
1	$23,940	$1,995	$461
2	$32,460	$2,705	$624
3	$40,980	$3,415	$788
4	$49,500	$4,125	$953
Additional People	+$8,520 / person	+$710 / person	+$164 / person

If you enroll in CAP you could benefit from having a set monthly payment based on a percentage of income or the average bill at your property (whichever is lower). The percentage of income is between 4% and 9% for a heating customer. Additional benefits include bill forgiveness and forgiveness of past due balances.

CAP participants are required to recertify when applicable in order to stay enrolled in the program and receive CAP benefits. You will receive a recertification notice, including an application form, from UGI when it is time to recertify. We also encourage CAP customers to apply for LIHEAP each year.

Thank you,

UGI Utilities

UGI Gas Exhibit BJM-4R

Energy to do more®

May 4, 2026

{Customer Name}
{Customer Mailing Address}
{Mailing City State ZIP}

Dear {Customer Name}«Customer_Name»,

Our records indicate you have, in the past, received a LIHEAP grant. Based on this information, you may qualify for enrollment in the UGI Customer Assistance Program (CAP) for account {Account Number}. Enrollment in the CAP Program will assist you in managing your monthly energy bill, is free and has no impact on your credit score.

If you are eligible and interested in enrolling in the UGI Customer Assistance Program, please complete the enclosed Pennsylvania Utility Assistance Application Form, and return it to: {CBO Name, Address}.

Customer Assistance Program (CAP) Income Guidelines 2026

Household Members	Annual Income	Monthly Income	Weekly Income
1	$23,940	$1,995	$461
2	$32,460	$2,705	$624
3	$40,980	$3,415	$788
4	$49,500	$4,125	$953
Additional People	+$8,520 / person	+$710 / person	+$164 / person

If you enroll in CAP you could benefit from having a set monthly payment based on a percentage of income or the average bill at your property (whichever is lower). The percentage of income is between 4% and 9% for a heating customer. Additional benefits include bill forgiveness and forgiveness of past due balances.

CAP participants are required to recertify when applicable in order to stay enrolled in the program and receive CAP benefits. You will receive a recertification notice, including an application form, from UGI when it is time to recertify.

Thank you,

UGI Utilities

UGI Gas Exhibit BJM-5R

APPENDIX H

UGI Utilities, Inc. – Gas Division

UGI Utilities, Inc. – Electric Division

UGI Utilities, Inc.

Consumer Education and Outreach Plan

Docket Nos. M-2025-

Filing Date: April 1, 2025

I. BACKGROUND

On March 31, 2020, amendments to the Pennsylvania Public Utility Commission's ("Commission") Customer Assistance Program ("CAP") Policy Statement (at 52 Pa. Code § 69.261, et al.) became effective, including a provision stating that consumer education and outreach plans ("CEOP") should be developed. The CEOP should target low-income customers and be incorporated into a utility's Universal Service and Energy Conservation Plan ("USECP"). 52 Pa. Code § 69.265(8)(i). Additionally, CEOPs should tailor and align educational outreach efforts with the demographics of the utility's service territory. 52 Pa. Code § 69.265(8)(vi)(B). Further, per 52 Pa. Code §§ 69.265(8)(vi)(B)(I-II) and 69.265(8)(vi)(C), CEOPs should include: (1) specific efforts to educate and enroll customers at/below 50% of the Federal Poverty Income Guidelines ("FPIG"); (2) resources, translation services and translated materials for Limited English Proficiency ("LEP") customers; and (3) referrals to other appropriate support services. Accordingly, UGI hereby provides its CEOP in accordance with the above-described provisions for incorporation into its 2025-2030 USECP.

II. PURPOSE

This CEOP is structured to perform the following educational outreach activities in accordance with 52 Pa. Code § 69.265(8):

A. Educate all customers regarding the benefits and responsibilities of CAP participation.
B. Educate all customers regarding the importance of energy conservation.
C. Perform focused CAP education outreach to the demographics comprising UGI's service territory.
D. Educate and enroll interested and eligible customers in CAP with income levels at or below 50% of the FPIG.
E. Utilize translated materials and services for LEP customers in UGI's service territory.
F. Refer low-income customers to appropriate support services.

The above activities are performed in conjunction with Community Based Organizations ("CBOs") that UGI partners with to perform daily operations for UGI's low-income programs.

III. UGI'S CEOP

A. Universal Service CEOP Roles

Members of UGI's Universal Services Program team educate customers about USECP program offerings through various means. These employees include one Manager Universal Service Programs, one Senior Analyst Universal Service Programs, one Universal Service Program Administrator, one Senior Customer Outreach Representatives, and six Customer Outreach Representatives.

These employees also are subject matter experts for specific programs including CAP, Operation Share, Low Income Usage Reduction Program ("LIURP"), and Low Income Home Energy Assistance Program ("LIHEAP"). Education for these programs is provided by way of in-person Winter Assistance Relief Mobilization ("WARM") events, direct mail campaigns, responses to email inquiries, phone conversations, social media resources, and UGI's website. In addition, UGI provides educational materials to its CBOs (e.g., Conservation Literature, Universal Service Plan brochures, CAP application packets, etc.) for community distribution.

Moreover, two LIHEAP Outreach Representatives provide support to County Assistance Offices ("CAO"), but typically do not provide direct program education to customers.

B. Education Regarding the Benefits and Responsibilities of Low Income Program Participation

UGI's customers receive general information regarding the Company's Universal Services programs: Operation Share, CAP, LIURP,[1] and Customer Assistance Referral Evaluation

[1] The LIURP Weatherization Program is offered to reduce the energy consumption of low-income customers through the installation of energy conservation measures and energy conservation education. Eligible electric non heating customers may receive in home or telephonic energy education sessions.

Services ("CARES"),[2] as well as other information about ways they can reduce their bills or obtain assistance in paying their bills, as specified in Table 1 below.

TABLE 1

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
Bill Assistance Insert	Energy Efficiency and Conservation ("EE&C") Programs for Gas & Electric. CAP, LIHEAP, Operation Share, and LIURP household income qualification and program education.	Every other month, beginning Oct. 2023	English, Spanish	Mail	All mail customers	Exhibit 1: Customer Programs Insert
Telephone On-Hold Message	Bill pay help contact information.	Continuous	English, Spanish	Phone calls into UGI Call Center	All customers who call UGI	N/A
UGI Website Assistance Page	Low Income Program and EE&C content.	Continuous	English	Online	All customers who visit UGI.com	Exhibit 2: Links to Assistance Webpages
News Releases	LIHEAP season opening information (e.g., grant period, contact information to apply, poverty level guidelines, etc.)	Released 1 to 4 weeks prior to November 1 each year	English	Mail, email, and websites	All customers	Exhibit 3: LIHEAP News Release
New Customer Guide	Contact information for payment arrangements, Budget Billing, assistance programs, fuel funds, and agency referrals. Includes a brief summary of LIHEAP, CAP, Operation Share and LIURP with contact information.	When new accounts are established.	English	Mail, Email	All new customers	Exhibit 4: Welcome Packet

[2] Each CARES customer may receive an informational mailing. The mailing contains educational material on each of the assistance programs and any other referral information that may be helpful to the customer. Customer Outreach employees maintain contact with CBOs through referrals and educational services.

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
New Income Guidelines	Presents (1) the new annual income guidelines; (2) USECP information; and (3) a link to UGI's website assistance form.	February/ March	English, with contact information in Spanish	Email	Residential customers who provided email addresses when establishing service or who have an online portal account	Exhibit 5: Income Guidelines Email
Program Awareness	Awareness messaging targeted at customers in situations that could benefit from USECP programs with application information.	Bi-monthly	English	Text	Residential customers who opted in to receive assistance text messages	Exhibit 6: Program Awareness Messaging
Ebill Assistance Links	Bill pay assistance website link.	Continuous	English	Online Ebill Portal	Ebill customers	Exhibit 7: Ebill Assistance Website Link
Social Media Posts	Various benefits messaging prompting customers to contact UGI about USECP enrollment.	Quarterly	English	Facebook	All customers who access UGI on Facebook.	Exhibit 8: 2024 Social Media Posts

The communications included in Table 1 and their attendant exhibits demonstrate that the Company utilizes various forms of marketing channels to promote its USECP programs by outlining the benefits and responsibilities of each program.

1. Targeted Outreach about USECP Programs

UGI also performs more targeted outreach to customers about the Company's USECP programs as specified in Table 2 below. The direct targeting provides customer-specific information (e.g., CAP monthly payment, CBO or CAO information) to low-income customers. These communications encourage program enrollment to help eligible customers.

TABLE 2

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
USP Brochure	Details of each USECP program's benefits and eligibility requirements.	Brochures sent upon request to CBOs and then handed out by CBOs	English, Spanish	Handout by CBOs	Low-income customers who engage with CBOs	Exhibit 9: USP Brochure
Self-Reported Low Income ("SRLI") Email Journey	Email series to SRLI customers regarding USECP program benefits with a link to begin enrollment process. Each	Bi-weekly over the course of 8 weeks	English	Email	SRLI customers who provide email addresses	Exhibit 10: SRLI Emails

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
	email showcases a different program. The final email provides info about text campaign.					
LIHEAP Email	LIHEAP explanation, with income guidelines, link to COMPASS website, information on how to apply (including UGI account number). Also provides LIURP benefits and enrollment information, link.	March	English	Email	All residential customers who provided email addresses.	Exhibit 11: LIHEAP Email
Utility File Transfer (UFT) LIHEAP	Targets LIHEAP recipients who received less than the maximum grant amount. Aimed at getting them additional LIHEAP funds. Customer must opt-in to receive.	February through end of LIHEAP season.	English	Phone Dialer	LIHEAP recipients who received less than the maximum grant for current program year.	Exhibit 12: UFT Transcript
Conservation Packets/Literature	Conservation benefits with a paragraph about available assistance in 10 languages. Contains energy saving tips and information about EE&C Programs.	Materials sent to CBOs upon request.	English (with multi-language sheet enclosed)	Handouts by CBOs and Mail	Low-income customers who engage with CBOs.	Exhibit 13: Conservation Packet Literature
Solicitation of (SRLI but no CAP)	Explains CAP benefits and requests that SRLI customers apply for CAP.	Electric – Mailers sent twice a year in spring and fall until auto-enrollment begins in January 2024. Gas – Mail and email sent before fall.	English	Mail and Email	Customers with SRLI indicators who are not enrolled in CAP	Exhibit 14: SRLI No CAP Mail & Email

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
CAP Recertification	Targeted outreach mailings to CAP customers in a two-step process. For Step 1, a letter is sent 30 days prior to the recertification due date. For Step 2, a letter is sent on the recertification due date.	As needed	English	Mail	CAP customers who need to recertify for program enrollment	Exhibit 15: CAP Recertification Letters
Video	Overview of CAP and refers customers to LIHEAP and LIURP.	Ongoing since November 2023.	English	UGI.com, YouTube, and Email	Non-CAP SRLI customers at Level 0 or Level 1 and LIHEAP No CAP Eligible customers; general public	Exhibit 16: UGI CAP (English) video link.
Video	Overview of CAP and refers customers to LIHEAP and LIURP (Spanish)	Ongoing. Added to UGI.com (and YouTube) in July 2024.	Spanish	UGI.com	Any visitor to CAP pages of ugi.com	Exhibit 17: El Programa de Asistencia al Cliente (Spanish) video link.
Operation Share Bill Insert	Explains Operation Share program benefits and contains donation form.	December	English, Spanish	Mail	All customers	Exhibit 18: Operation Share Bill Insert
Expositions (“Boots on the Ground”) - USECP	Overview of low-income programs explaining situational assistance, benefits, with income guidelines and contact information.	UGI expos, movie nights and United Way events	English	Handout in giveaway bags	All customer attendees	Exhibit 19: BOTG Handout
WARM - In-Person Events to Enroll Income-Eligible Customers into Programs	UGI provides USP applications and reviews attendee accounts for applicable programs benefits.	Ongoing since October 2022	English, Spanish	In-person	Low-income customer attendees	Exhibit 20: WARM Marketing

Communication	Content	Frequency	Language	Distribution	Recipients	Exhibit
CAP Eligibility Landing Page	Find out if eligible for CAP by visiting website landing page	Ongoing	English	All assistance program collateral	UGI gas customers	Exhibit 21: CAP Eligibility Screen Capture

C. Educate and Enroll Interested and Eligible Customers within the 0-50% FPIG Range in Low Income Programs

The company anticipates starting targeted communications to the 0-50% FPL level once the 2026-2030 USECP is approved. These targeted communications are still under development. However, they will provide details about the various low income programs. For example. UGI is preparing a communication explaining that customers who receive SNAP, could qualify for utility bill assistance. Additionally, the UGI Outreach team is working closely with the Community Relations team to support various organizations that assist low-income customers (e.g., Power Packs Project, Wildheart Ministries[3]). Some of these events are focused on the 0%-50% FPL audience. Finally, as stated above, UGI is providing targeted communications to customers that self-report being low income.

D. Low Income Customer Conservation Education

Regarding conservation education for low-income customers, UGI provides Conservation Packets to its CAP and LIURP agencies for distribution. These packets include the following items:

- Adult coloring book (with energy saving tips)
- Child coloring book: "Sparky" the Energy Saving Squirrel
- Magnet with contact information to inquire about low-income and energy-saving programs
- Safety – "Smell Gas" steps
- Energy Saving Tips brochure
- Information regarding all energy assistance programs with translated content

E. Low-Income Referrals to Other Support Services

a. External Referrals

UGI refers its low income customers to other organizations that may be able to provide assistance based on the circumstances presented. For example, UGI has referred customers to local churches and food banks, Office of Aging, PA 211, Service Access & Management, Inc., etc. UGI also plans to engage with predominantly Spanish-speaking cultural organizations, such as the Spanish American Civil Associations ("SACA") and currently is in discussions with Centro Hispano. In July 2024 we sent safety brochures and assistance brochures to 27 cultural and 35 community-based organizations.

b. Internal USECP Referrals

Customers who express the need for a particular service, e.g., related to a protection from abuse order, are referred to UGI's CARES program. Customers do not need to be in any FPIG level to

[3] Power Packs Project is a non-profit organization that aims to improve the mental and physical health of children by helping their parents provide nutritious meals over weekends when school breakfast and lunch programs are unavailable to them. Outreach representatives will be attending an event in April 2025 at Wildheart Ministries (https://www.wildheartministries.net/ministries/love-the-hill).

participate. If a customer contacts the Call Center, states they are low income and requests specific information about a program, they are referred to UGI's Outreach team. The Outreach team will evaluate the customer's account to determine which programs may be beneficial. Next, the Outreach team sends the customer appropriate program information by mail, including applications and program benefit materials. The application contains information about which specific CBOs can assist the customer in enrolling in the most beneficial program(s).

UGI also performs Warm Referrals for both Electric and Gas customers, which automatically refers the customer to other low-income programs that may assist the customer (e.g., LIURP, Operation Share Grant, CARES). Specifically, the Company proactively determines if these customers qualify for benefits under these other programs and solicits them for participation. The customer does not need to apply for these programs. Benefits to qualifying customers include CAP enrollment, weatherization measures at residences, and/or energy assistance grants for heating bills.

F. Demographics-Focused Low-Income Customer Education

To determine the demographics of the low-income population in its service territory, UGI monitors census data periodically and obtains the languages spoken in the counties comprising its distribution systems. This information guides UGI's efforts for translating customer communications, as required in 52 Pa. Code § 56.91(b)(17) (relating to termination notice provisions in Spanish and other languages when 5% or more of the residents use those languages). Table 3 below provides UGI's demographic analysis as of December 2021. It provides counts for residential, CLI and ELI customers by county. It also shows what percentages of the residential customer counts are English speaking, Spanish speaking and Other language speaking. On a total residential customer basis, 89.22% of UGI's customers are English speaking, 5.73% are Spanish speaking, and 5.05% combined speak All Other languages.

G. Utilize Translated Materials and Service for LEP Customers

As Table 3 below shows, the demographics for UGI's CLI and ELI populations are mainly English and Spanish. A smaller contingent of these populations (i.e., All Other) speak Ukrainian, Russian, Italian, Hindi, French, German, Arabic, Japanese, and Simplified Chinese (all individually lower than 5%). The Company typically provides USECP program applications and education materials in English. Applications are provided in Spanish upon request. Tables 1 and 2 above show the materials that are provided in Spanish to customers.

The Company is working to create both English and Spanish versions of its low-income program forms and letters. The Spanish-translated versions will be sent to customers upon request initiated through our Customer Contact Center discussions. UGI also provides translation services to its low-income customers during phone inquiries, as needed. Translation services are available to LEP customers when calling UGI's Customer Contact Center. Upon request, UGI will secure an interpreter to aid customers inquiring about Universal Services. Additionally, UGI added a dedicated queue of Spanish-speaking Customer Service Representatives in 2024.

Additionally, the Company has distributed the following statements in multiple languages to let customers know that a translator can be provided if needed. The statements are as follows:

- Statement 1 (Conservation Packets): UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives can assist you by providing information on a variety of energy assistance programs, making referrals to local agencies, offering participation in fuel funds or establishing payment arrangements. Language service interpreters are available to help over the phone. Call (800) UGI-WARM or (800) 844-9276 to learn more.

- Statement 2 (CAP Application): If you need assistance paying your UGI bill or want to know more about programs available to help with your utility bill, contact UGI at (800) 276-2722. UGI has interpreters available, free of charge.

The statements (appearing in Exhibits A and B9 and XX, respectively) have been translated in Spanish, Ukrainian, Russian, Italian, Hindi, French, German, Arabic, Japanese, and Simplified Chinese.

Additionally, the statements have been distributed to UGI's CBOs and CAOs since May 2023. CBOs and CAOs will request additional supplies when needed. The flyers also will be included as an insert with all new applications for low-income programs.

Regarding WARM events, the Outreach team has program literature available in English and Spanish when attending all events. In addition, CBOs have UGI literature, e.g., the UGI Universal Service Program brochure, program applications and program benefit information, in both English and Spanish, and many CBOs offer bilingual services.

In-person WARM events occurred from October 2019 through March 2020. They were paused as a result of COVID-19. They re-started in October 2022. The UGI Outreach team works with local CBOs, local food banks, and other assistance agencies (e.g., senior centers) to advertise its WARM events. Additionally, WARM events are advertised on UGI's website, and through emails to residential customers within specific ZIP codes where the events are taking place. UGI's CBOs support UGI's efforts with these events to provide direct one-on-one support to customers and assist with program enrollment. Typically, UGI has a bilingual Outreach team member at each WARM event to provide assistance to LEP customers. In addition, during these events, Outreach team members utilize translation services provided by a vendor for languages other than English and Spanish, if needed. Also, agencies (e.g., the Commission, BeWise, Community Outreach organizations, Senior Support outfits) hosting events regularly have bilingual staff that are utilized for LEP customers.

BeWise is a half day human services conference promoting consumer awareness, utility education, and life management skills. These conferences are attended by agencies, school counselors, and other community workers that learn about the programs to provide education to their clients. UGI continues to work with BeWise, senior centers and other Community Outreach agencies to attend events to provide additional insight to available programs.

Since 2022, UGI has hosted WARM events at requested locations (Bethlehem, Lancaster City, Mount Joy, Manheim, and Mountville). Additionally, the Company recently (1) provided several local food pantries with Universal Service literature to distribute; (2) sent Universal Service program brochures to County Assistance Offices to distribute; and (3) created a CAP educational video and is considering potential future videos for other UGI low-income programs.

UGI also provides in-person support at similar events hosted by agencies – e.g., Community Outreach Events, Senior Expos. UGI personnel have attended Community Outreach Events, such as food pantry distributions, Angel Tree sign-ups (Salvation Army), back-to-school backpack distributions and AKA Energy Forums. Senior Expos typically host many vendors that provide information and giveaways for senior citizens. UGI personnel use these events as an opportunity to educate participants on programs that are available to qualified customers.

TABLE 3

December 2021	# of Residential	Est. Low Income	Confirmed Low Income	Language Spoken in Household			
a. Community Served	Customers	Customers	Customers	English	Spanish	All Others	Total
Adams	37	7	1	35	2	1	38
Bedford	621	179	16	607	5	9	621
Berks	71,774	18,697	1,986	60,161	8,405	3,208	71,774
Blair	481	141	12	468	3	10	481
Bradford	3,835	1,101	183	3,738	44	53	3,835
Bucks	7,817	1,070	69	6,997	217	603	7,817
Carbon	2,792	699	117	2,671	36	85	2,792
Centre	242	74	11	220	4	18	242
Chester	2,849	422	59	2,525	150	174	2,849
Clarion	3,334	1,147	112	3,242	21	71	3,334
Clearfield	2,145	674	105	2,076	33	35	2,144
Clinton	2,340	772	98	2,238	39	63	2,340
Columbia	7,107	2,075	321	6,879	83	145	7,107
Cumberland	43,280	7,076	588	39,995	814	2,471	43,280
Dauphin	49,545	12,416	1,663	44,462	2,289	2,794	49,545
Forest	650	233	16	620	22	8	650
Franklin	3,711	863	67	3,469	124	119	3,712
Fulton	3	1	12	3	0	0	3
Huntingdon	1,326	364	67	1,283	22	22	1,327
Lackawanna	58,907	17,460	2,592	54,542	1,897	2,468	58,907
Lancaster	72,761	16,590	1,391	61,388	4,577	6,796	72,761
Lebanon	20,310	4,578	521	18,472	1,245	593	20,310
Lehigh	51,796	13,545	1,890	41,235	6,904	3,657	51,796
Luzerne	73,528	21,639	3,698	68,278	3,110	2,140	73,528
Lycoming	18,420	5,093	916	17,845	217	357	18,419
McKean	3,798	1,233	179	3,686	59	53	3,798
Mifflin	2,580	816	124	2,344	12	225	2,581
Monroe	3,528	902	144	3,032	276	220	3,528
Montgomery	3,363	450	10	2,967	96	300	3,363
Montour	2,092	528	53	1,939	30	123	2,092
Northampton	51,684	9,908	1,269	45,203	3,525	2,956	51,684
Northumberland	11,492	3,363	582	11,051	182	260	11,493
Pike	1,032	213	15	935	49	48	1,032
Potter	5,918	2,028	237	5,765	54	98	5,917
Schuylkill	3,158	887	163	3,001	72	85	3,158
Snyder	2,019	517	53	1,889	19	111	2,019
Susquehanna	301	80	15	293	3	5	301
Tioga	13,086	3,949	514	12,789	99	198	13,086
Union	1,632	400	25	1,449	78	105	1,632
Venango	878	257	28	859	9	11	879
Wayne	2,183	594	107	2,061	62	60	2,183
Wyoming	349	81	7	339	4	5	348
York	1,454	316	14	1,357	57	40	1,454
Total	**610,158**	**153,437**	**20,050**	**544,408**	**34,949**	**30,803**	**610,160**
				89.22%	5.73%	5.05%	

Get to Know UGI Customer Programs

UGI ENERGY EFFICIENCY & CONSERVATION PROGRAM

UGI residential customers can receive rebates* when purchasing and installing eligible, high-efficiency equipment. At UGI, we know that our customers value saving money and energy. Making the decision to install energy efficient products is a great way to do both!

GAS REBATES

Equipment	Minimum Efficiency	Rebate Amount
Smart Thermostat	Energy STAR®	$50
Tankless Water Heater	Energy STAR®	$400
Furnace	Energy STAR®	$500
Boiler	94+ AFUE	$1,200
Combi Boiler	94+ AFUE	$1,500

All equipment must be powered by natural gas. Must apply within 90 days of purchase, Rate Classes eligible are R, RT, N or NT.

ELECTRIC REBATES

Equipment	Efficiency	Rebate Amount
Smart Thermostat	Energy STAR®	$50
Room Air Conditioner	Energy STAR®	$25
Clothes Washer	Energy STAR®	$25
Dehumidifier	Energy STAR®	$25
Refrigerator	Energy STAR®	$25
Dishwasher	Energy STAR®	$25

*Rebate amounts and availability subject to change. For current rebates, visit **www.ugi.com/savesmart**.*

INCOME-BASED PROGRAMS*

Maximum Household Income Before Taxes for CAP and LIHEAP					
Number of Household Members	1	2	3	4	Each Additional Person
Monthly Income	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for LIURP					
Number of Household Members	1	2	3	4	Each Additional Person
Monthly Income - Gas Customers	$2,430	$3,287	$4,143	$5,000	$857/person
Monthly Income - Electric Customers	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for Operation Share					
Number of Household Members	1	2	3	4	Each Additional Person
Monthly Income - Gas Customers	$3,038	$4,108	$5,179	$6,250	$1,071/person
Monthly Income - Electric Customers	$2,430	$3,287	$4,143	$5,000	$857/person

Low Income Home Energy Assistance Program (LIHEAP)

LIHEAP is a grant program run by the state of Pennsylvania. Grants do not have to be paid back. The program opens in November and typically ends in April or May of the following year.

Learn more at **www.ugi.com/LIHEAP**

Customer Assistance Program (CAP)

CAP is a personalized monthly payment, based on the lesser of an income-based payment or average bill. Each on-time payment provides debt forgiveness.

Learn more at **www.ugi.com/CAP**

Low Income Usage Reduction Program (LIURP)

LIURP provides energy-saving measures like insulation, air sealing, heating system repair and maintenance, and safety measures such as smoke & carbon monoxide detectors.

Learn more at **www.ugi.com/LIURP**

Operation Share Energy Fund

If you've experienced a hardship like loss of job, death of the main wage earner or sickness, and your income is within the guidelines shown above, you should apply for an Operation Share grant.

Learn more at **www.ugi.com/OpShare**

*Income levels are updated in January of each year. FPL guidelines may change for individual programs. For current information, visit **www.ugi.com/incomeguidelines**.*

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Informese sobre los programas de asistencia para clientes de UGI.

PROGRAMA DE EFICIENCIA Y CONSERVACIÓN ENERGÉTICA DE UGI

Los clientes residenciales de UGI pueden recibir reembolsos* al comprar e instalar equipos elegibles de alta eficiencia

REEMBOLSOS DE GAS

Equipos	Eficiencia Minima	Cantidad del reembolso
Termostato inteligente	†Energy STAR®	$50
Calentador de agua sin tanque	†Energy STAR®	$400
Equipos de calefacción (Boila)	†Energy STAR®	$500
Boiler	94+ AFUE	$1,200
Combo de Equipo de calefacción	94+ AFUE	$1,500

**Todos los equipos deben ser de gas natural. Debe aplicar en un plazo de 90 dias de su compra, los clientes elegibles deben de ser R, RT, N o NT.*

†Equipos de reducción de energía (Energy STAR®)

REEMBOLSOS ELÉCTRICOS

Equipos	Eficiencia	Cantidad del reembolso
Termostato inteligente	†Energy STAR®	$50
Aire acondicionado	†Energy STAR®	$25
Lavadora de ropa	†Energy STAR®	$25
Deshumidificador	†Energy STAR®	$25
Refrigerador	†Energy STAR®	$25
Lava vajillas	†Energy STAR®	$25

Los montos de rembolsos estan sujetos a cambios. Para los rembolsos actuales visite **www.ugi.com/savesmart.*

†Equipos de reducción de energía (Energy STAR®)

PROGRAMAS BASADOS EN SUS INGRESOS*

Ingreso total de familia maximo ante de impuestos para el programa de CAP y LIHEAP					
Numero total de miembros en el hogar	1	2	3	4	Por cada miembro adicional
Ingresos Mensuales	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for LIURP					
Numero total de miembros en el hogar	1	2	3	4	Por cada miembro adicional
Ingresos Mensuales - Gas Customers	$2,430	$3,287	$4,143	$5,000	$857/person
Ingresos Mensuales - Electric Customers	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for Operation Share					
Numero total de miembros en el hogar	1	2	3	4	Por cada miembro adicional
Ingresos Mensuales - Gas Customers	$3,038	$4,108	$5,179	$6,250	$1,071/person
Ingresos Mensuales - Electric Customers	$2,430	$3,287	$4,143	$5,000	$857/person

Programa de Asistencia de Energía para Hogares de Bajos Ingresos (LIHEAP)

LIHEAP es un programa de ayuda administrado por el estado de Pensilvania. Las ayudas otorgadas no tienen que devolverse. Los programas abren en Noviembre y normalmente terminan en Abril o Mayo del año siguiente.

Obtenga más información en **www.ugi.com/LIHEAP**

Programa de Asistencia al Cliente (CAP)

CAP es un pago mensual personalizado, determinado basado en el promedio de su factura o ingresos mensuales, el que sea más bajo de los dos. Cada pago a tiempo ayuda a eliminar un porcentaje de su deuda acumulada.

Obtenga más información en **www.ugi.com/CAP**

Programa de Reducción de consumo (LIURP)

LIURP proporciona medidas de ahorro de energía como aislamiento, sellado de aire, calefacción, reparación y mantenimiento del sistema, y medidas de seguridad tales como humo y detectores de monóxido de carbono.

Obtenga más información en **www.ugi.com/LIURP**

Fondos de campaña para ayudas de Energía

Si ha experimentado una dificultad como la pérdida de trabajo, la muerte del jefe de familia o enfermedad, y sus ingresos se encuentran dentro de las pautas que se muestran anterior, puede solicitar ayuda de los fondos de la campaña Operation Share.

Obtenga más información en **www.ugi.com/OpShare**

Los niveles de ingresos se actualizan en Enero de cada año. Las pautas de FPL pueden cambiar para programas individuales. Para obtener información actualizada, visite **www.ugi.com/incomeguidelines.*

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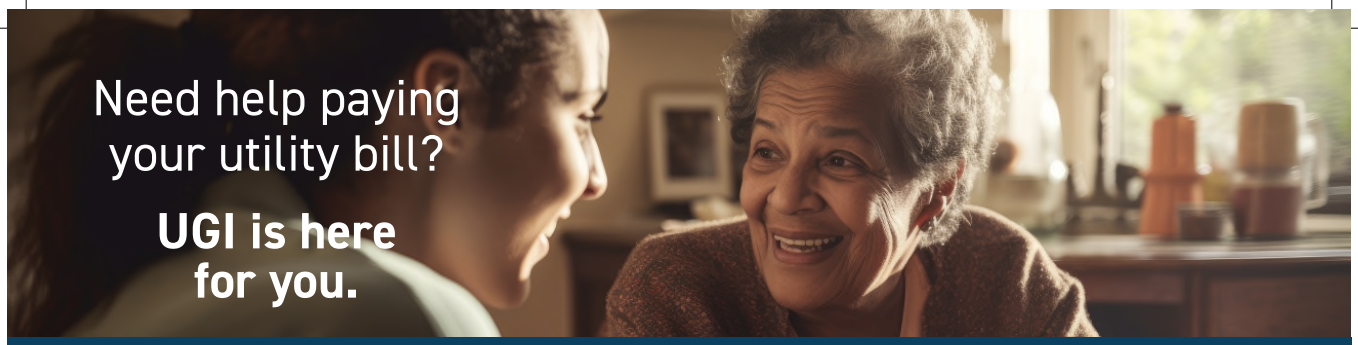

Explore your options and get the help you need!

INCOME-BASED PROGRAMS*

Maximum Household Income Before Taxes for CAP and LIHEAP					
Number of Household Members	**1**	**2**	**3**	**4**	**Each Additional Person**
Monthly Income	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for LIURP					
Number of Household Members	**1**	**2**	**3**	**4**	**Each Additional Person**
Monthly Income - Gas Customers	$2,430	$3,287	$4,143	$5,000	$857/person
Monthly Income - Electric Customers	$1,823	$2,465	$3,108	$3,750	$643/person

Maximum Household Income Before Taxes for Operation Share					
Number of Household Members	**1**	**2**	**3**	**4**	**Each Additional Person**
Monthly Income - Gas Customers	$3,038	$4,108	$5,179	$6,250	$1,071/person
Monthly Income - Electric Customers	$2,430	$3,287	$4,143	$5,000	$857/person

Low Income Home Energy Assistance Program (LIHEAP)

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If you've experienced a hardship like loss of job, death of the main wage earner or sickness, and your income is within the guidelines shown above, you should apply for an Operation Share grant.

Learn more at **www.ugi.com/OpShare**

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Rebate amounts and availability subject to change. For current rebates, visit **www.ugi.com/savesmart.*

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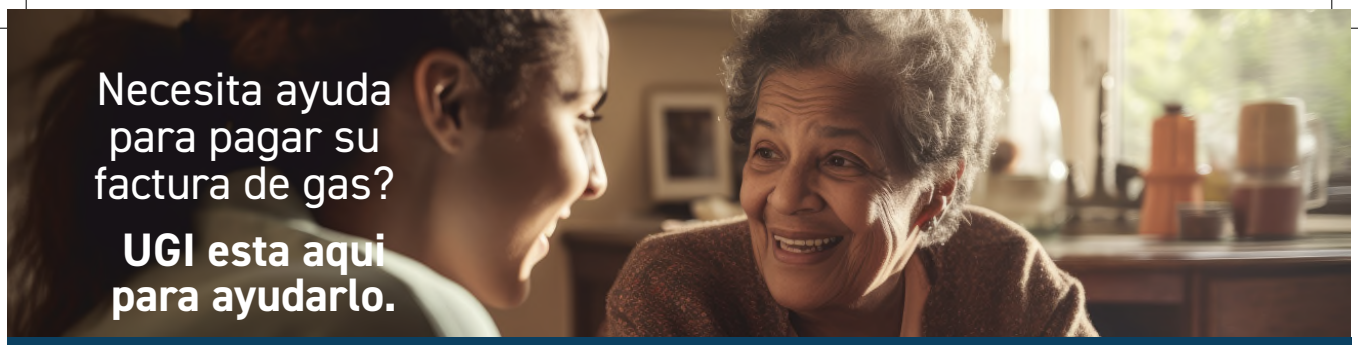

Explora sus opciones y reciba la ayuda que necesita!

PROGRAMAS BASADOS EN SUS INGRESOS*

Ingreso total de familia maximo ante de impuestos para el programa de CAP y LIHEAP					
Numero total de miembros en el hogar	**1**	**2**	**3**	**4**	**Por cada miembro adicional**
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Maximum Household Income Before Taxes for LIURP					
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PROGRAMA DE EFICIENCIA Y CONSERVACIÓN ENERGÉTICA DE UGI

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Calentador de agua sin tanque	†Energy STAR®	$400
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Boiler	94+ AFUE	$1,200
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**Todos los equipos deben ser de gas natural. Debe aplicar en un plazo de 90 dias de su compra, los clientes elegibles deben de ser R, RT, N o NT.*

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REEMBOLSOS ELÉCTRICOS

Equipos	Eficiencia	Cantidad del reembolso
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†Equipos de reducción de energía (Energy STAR®)

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https://www.ugi.com/assistance-programs/

https://www.ugi.com/assistance-programs/online-form/

https://www.ugi.com/assistance-programs/CAP/

https://www.ugi.com/assistance-programs/LIHEAP/

https://www.ugi.com/assistance-programs/LIURP/

https://www.ugi.com/assistance-programs/operation-share/

Link to Article

Energy to do more®

UGI Reminds Eligible Customers How to Get Help With Heating Costs

Home heating season is almost here, and UGI continues to urge eligible natural gas and electric customers to apply for federal Low Income Home Energy Assistance Program (LIHEAP) funds to help cover costs this winter. Applications will be accepted by the Pennsylvania Department of Human Services beginning November 4, 2024, through April 4, 2025.

"UGI is committed to delivering safe and reliable energy services, while also working to make it affordable," says Dan Adamo, UGI Vice President of Customer Relations. "LIHEAP as well as UGI's income eligible customer assistance programs bring real savings to thousands of our customers each year."

Last winter, nearly 26,000 UGI customers received LIHEAP grants totaling more than $10 million.

LIHEAP grants help customers with limited or fixed incomes pay their heating bills, repair or replace a heater, avoid utility service shut off, and assist in restoring a terminated service. **LIHEAP grants do not need to be repaid.** Customers interested in applying for LIHEAP should contact UGI. Company representatives will provide customers with information on the application process and eligibility requirements and can also help in completing and submitting the required forms.

LIHEAP funds are limited and available on a first-come, first-served basis to qualifying customers. UGI urges customers to submit a LIHEAP application as soon as possible. For more information on LIHEAP, customers can call UGI at 1-800-UGI-WARM (1-800-844-9276) or visit www.ugi.com/liheap .

Get in Touch

Key Takeaways

- *Eligible natural gas and electric customers can apply for the federal Low Income Home Energy Assistance Program (LIHEAP).*
- *Applications will be accepted by the Pennsylvania Department of Human Services beginning November 4, 2024, through April 4, 2025.*
- *UGI also offers company-sponsored customer assistance programs.*

Explore Assistance Programs

Media Gallery

Household Members	Annual Income	Monthly Income	Weekly Income
1	$ 22,590	$ 1,883	$ 434
2	$ 30,660	$ 2,555	$ 590
3	$ 38,730	$ 3,228	$ 745
4	$ 46,800	$ 3,900	$ 900
5	$ 54,870	$ 4,573	$ 1,055
6	$ 62,940	$ 5,245	$ 1,210
7	$ 71,010	$ 5,918	$ 1,366
8	$ 79,080	$ 6,590	$ 1,521
Above 8	+$8,070/person	+$673/person	+$155/person

Contacts

John Mason
jmason@ugi.com
(610) 334-7135
Principal Communications Leader

To qualify for LIHEAP funds, a customer must provide proof of income, a recent heating bill, and name, birth date and Social Security number for each household member.

LIHEAP applicants now have the option of sharing certain application information directly with public utilities, to help with the enrollment process and to help determine eligibility in additional UGI-sponsored programs. To opt in, just look for the checkbox on the application.

Income eligibility for LIHEAP through January 31, 2025:

Household Members	Annual Income	Monthly Income	Weekly Income
1	$ 22,590	$ 1,883	$ 434
2	$ 30,660	$ 2,555	$ 590
3	$ 38,730	$ 3,228	$ 745
4	$ 46,800	$ 3,900	$ 900
5	$ 54,870	$ 4,573	$ 1,055
6	$ 62,940	$ 5,245	$ 1,210
7	$ 71,010	$ 5,918	$ 1,366
8	$ 79,080	$ 6,590	$ 1,521
Above 8	+$8,070/person	+$673/person	+$155/person

UGI also offers company-sponsored assistance programs, including:

UGI's **Customer Assistance Program (CAP)** offers qualifying income-eligible customers a more manageable monthly energy bill. UGI provides CAP participants with a monthly payment amount based on gross income, household size and energy usage. When CAP bills are paid on or before the due date, the difference between the amount billed and the actual amount used may be forgiven.

The **Low-Income Usage Reduction Program,** or **Weatherization**, offers free installation of energy conservation measures to help make energy bills more affordable. Possible energy saving measures include ceiling insulation; floor, duct, and hot water pipe insulation; caulking and weather-stripping, gas heater repairs and water flow restrictors.

The **Operation Share Energy Fund** provides energy assistance grants to qualifying customers who have trouble paying their heating bills. This community-based program is funded by a corporate donation by UGI as well as voluntary donations from UGI employees, UGI customers and concerned citizens. UGI works with dozens of community agencies to administer Operation Share funds.

C.A.R.E.S. (Customer Assistance and Referral Evaluation Service) can provide referrals to other helpful programs in the community. These programs can include LIHEAP, budget counseling, and State Weatherization or Office of Aging programs.

UGI can also assist eligible customers by setting up a **Payment Plan** if a bill is higher than expected and there is difficulty paying the entire amount.

A **Budget Billing Plan** estimates your annual energy usage and spreads out that amount evenly over the budget billing period to calculate the monthly amount a customer pays. UGI reviews each customer's Budget Billing Plan every three months to determine actual energy usage and make any necessary adjustments to monthly payments.

UGI encourages customers who may qualify for any of these programs to contact the company.

UGI Utilities, Inc. is a natural gas and electric utility company that serves more than 740,000 customers. Additional information about UGI Utilities, Inc. is available at www.ugi.com.

Welcome Home

Customer Information Guide

Energy to do more®

Nice to Meet You!

Thank you for trusting your family's energy needs to UGI.

We know that safe, reliable, and affordable energy is a necessity for you, whether you use it to keep your home warm, your water hot, or your lights on. That's why we take pride in delivering your fundamental energy needs through dependable service.

With UGI as your energy supplier, you get:

- Energy questions answered by knowledgeable staff
- Expert emergency service when you need it, day or night, from skilled employees
- Options to help manage your new account and control expenses

We pride ourselves on being a responsive, engaging energy company. Every day we strive to exceed your expectations.

In this guide, you'll find information on how your service works and how to save money. You can also visit **www.ugi.com** at any time or call 800-276-2722 for even more information.

Thank you again for choosing UGI. With our dependable service, you now have the **energy to do more.**

Headquarters:
Denver, PA
Total Employees:
~1,700
Natural Gas Pipeline Network:
~12,400 miles
Electric Line Network:
~2,700 miles
Annual Employee Volunteer Hours:
~40,000 hours

Applies to natural gas customers

Applies to electric customers

At a Glance

UGI Utilities, Inc. is a natural gas and electric utility committed to delivering reliable, safe, and affordable energy to our 740,000 customers in 46 counties in Pennsylvania and one county in Maryland.

Understanding Your Bill

1 ***Customer Account Number***
Please have this number ready when you contact us about your account.

2 ***How to Contact UGI***
Use this contact information for questions regarding your bill or service.

3 ***Next Scheduled Reading***
This is the scheduled date of your next UGI meter reading.

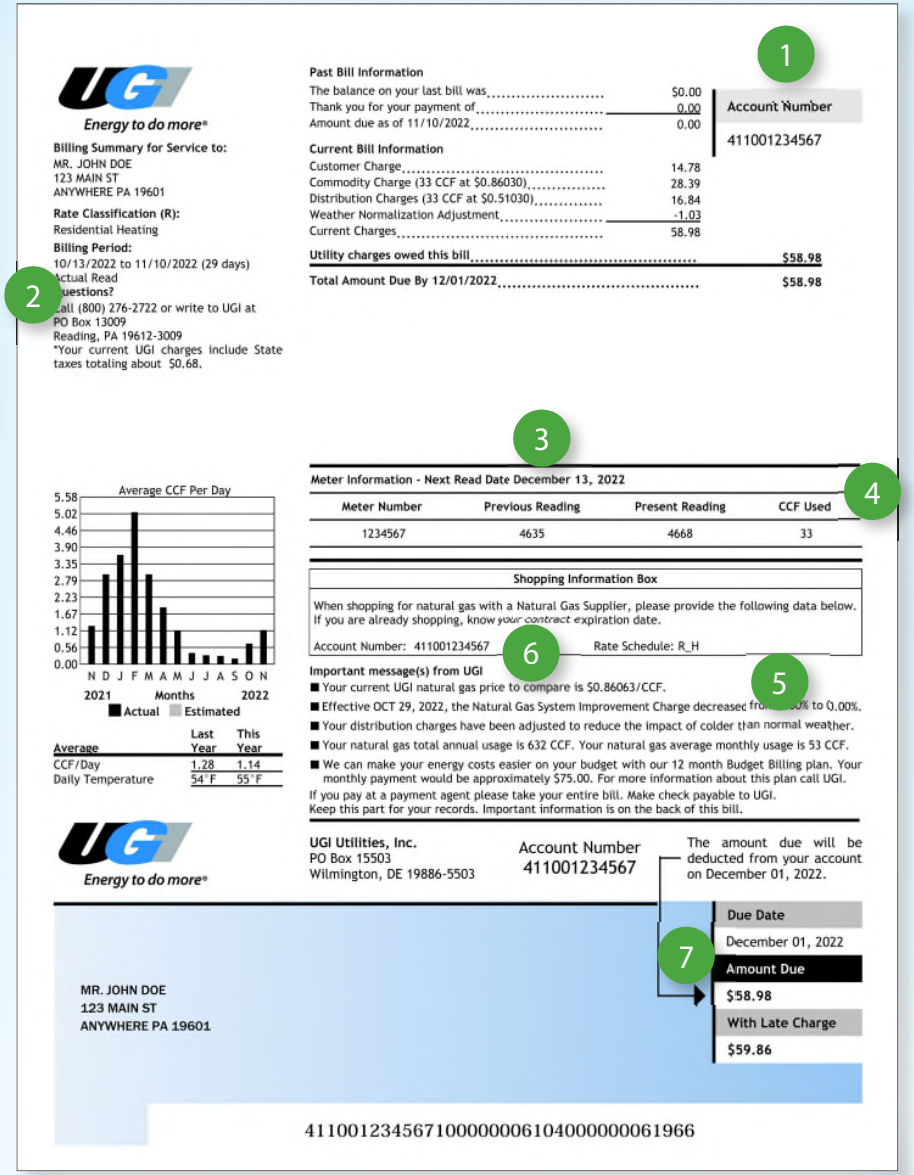
4 ***Meter Reading***
The meter reading for the current billing period and amount of energy used; natural gas is shown in CCFs (1 CCF = 100 cubic feet of gas) and electric in kWh. Our personnel are scheduled to read your meter monthly. However, there are occasions when you may receive an estimated bill. We base estimates on usage history and the actual temperature during the billing period.

5 ***Price Comparison***
Your current price to compare when shopping for an alternate energy supplier.

6 ***Messages***
Important messages from us regarding programs you may participate in, such as budget billing and the "GET Gas" program.

7 ***Due Date/Amount Due***
The amount currently owed to us and the date your payment is due.

If you have any questions or want more information, visit **www.ugi.com/billpay** or call 800-276-2722.



Paying Your Bill

Online at ugi.com

When you enroll in Paperless Billing, you'll receive an email alert when your monthly bill is available. Sign up quickly and easily when you register your account in our Online Account Center at **www.ugi.com**. Not only will you reduce clutter and simplify your life, but you'll also be able to view and download your monthly bills and usage, schedule future payments, and receive paperless billing exclusive email reminders when your bill is nearing its due date.

All UGI customers can make one-time payments via bank account or credit card at no additional charge. To view your payment options, **www.ugi.com/billpay**.

Other Payment Methods

- **Phone -** Call 800-276-2722 to pay your bill from your checking account, debit or credit card with no fee.
- **Mail -** Mail payments to P.O. Box 15503, Wilmington, DE 19886-5503. Always include your account number on your check.
- **Payment Agency -** Visit **www.ugi.com** or call us for approved payment agency locations. Walk-in payment centers may collect a fee for their service.

Payment Agreements for Past-Due Bills

If you have a problem paying your bill, please call us at 800-276-2722. Our customer care agents are happy to discuss options available to you.

Due Date Extensions

If you are on a permanent fixed income, our Due Date Extension program gives you additional time to deposit monthly checks so you can avoid late fees. Call us for an application.

Third-Party Notification Program

With this program, we send a copy of any past-due and shut-off notices to a designated third party—any friend, relative, caregiver, or even a preferred social services agency. **IMPORTANT: The third party is not responsible for paying any of your bills.** We simply give the designated party the opportunity to remind you to pay your bill and keep your account up to date. Call us to sign up.

Budget Billing

If your electric or gas usage varies widely from month to month or seasonally, our budget billing plan will spread your costs evenly throughout the year. Enrollment in this plan is free of charge. Sign up at **www.ugi.com** or call us with your UGI customer number handy.

AutoPay

Enrolling in this plan will save you time each month by automatically transferring your bill amount from your checking or savings account. Visit **www.ugi.com** or call us to sign up.

Income-Based Customer Assistance Programs

UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives can provide information on energy assistance programs and fuel funds, make referrals to local agencies, or establish payment arrangements. Call 800-UGI-WARM or 800-844-9276 to learn more. Typically, assistance is available for households with income up to 250% of the Federal Poverty Levels however, program eligibility is determined during the enrollment process. Programs include:

- Low Income Home Energy Assistance Program (LIHEAP) – Grant program run by the commonwealth of PA, which does not have to be paid back. Apply online at https://compass.state.pa.us or phone the LIHEAP Hotline at 866-857-7095.
- UGI Customer Assistance Program (CAP) – A personalized monthly payment plan based on percentage of income or average bill. Learn more at www.ugi.com/CAP.
- Operation Share – Grant program for customers experiencing a hardship like death of wage earner, sickness or loss of job, which does not need to be paid back. Call 800-UGI-WARM.
- UGI Low Income Usage Reduction Program (LIURP) – A program providing energy-saving repairs and upgrades to your home, at no cost to you. Visit www.ugi.com/LIURP to learn more.

Using Your New Energy Service Safely

Natural Gas Safety

Natural Gas is Naturally Odorless

To make it detectable, a chemical known as *Mercaptan* is added. It has a smell that is similar to rotten eggs. If you smell this odor, you need to act. There is **no cost** to you for UGI to investigate a natural gas odor.

What to Do if You Smell Gas

- **LEAVE** the inside of a building immediately. Take everyone and pets with you. Leave the door open if possible, and proceed to a safe location where you can no longer smell the odor of natural gas (approximately 500 feet away from the building).
- **CALL UGI's** gas emergency line 800-276-2722 from a safe location, 24 hours a day, 7 days a week, if you smell natural gas indoors, outdoors, or near a gas meter.
- **CALL 911** from a safe location if you ever hear or see natural gas blowing anywhere.

Use your eyes and ears as well.

Be aware of any indication of a possible natural gas pipeline leak, including:

- Air blowing the dirt, grass, or trees near a pipeline
- Bubbling or blowing air in a pond or stream
- Dead grass or plants in an otherwise green area
- Flames coming out of the ground
- Unusual hissing sounds

If you notice signs of a possible leak, contact UGI at 800-276-2722 or call 911 from a safe location.

What NOT to Do if You Smell Gas

- DO NOT use phones (standard or cellular), computers, appliances, elevators, lamps, garage door openers, or electrical devices if an odor of gas is present.
- DO NOT touch electric outlets, switches or doorbells.
- DO NOT smoke or use a lighter, match or other flame.
- DO NOT operate vehicles or power equipment where leaking gas may be present.
- DO NOT try to re-light a pilot light.
- DO NOT e-mail UGI or post emergency notifications on our social media if you smell natural gas or suspect a natural gas leak. *Please call UGI or 911.*
- DO NOT re-enter a building until it has been inspected by a UGI technician.

Visit www.ugi.com for more information, and teach your family what to do, and what NOT to do, if anyone ever notices the odor that is added to odorless natural gas.

Carbon Monoxide Safety

While natural gas has a scent added to it, incomplete combustion of ANY fossil fuel could produce an odorless, tasteless, and colorless gas called carbon monoxide (CO). Here's what you need to know about CO to protect yourself:

Protect your home with CO detectors.

- CO can enter living spaces in your home as a result of a malfunctioning appliance or blocked chimney.
- All fuel-burning equipment should be installed and regularly serviced by an experienced professional.
- All fuel-burning equipment requires proper venting and air flow for safe operation. Do not install equipment in a confined space. When renovating, have a professional specify space required for fuel-burning equipment.
- Signs that you may have a CO problem include: water vapor condensing on windows (other than normal bathroom and kitchen moisture), pets acting lethargic or lazy, headaches, dizziness, flu-like symptoms, and nausea.
- A CO detector should be installed on each floor of a home, particularly near every sleeping area.
- If you are alerted by your CO detector, or if you suspect CO poisoning, move to fresh air and call UGI or 911.

Electric Safety

Electrical emergencies can happen anywhere, anytime. Follow these tips to increase your safety in any situation.

Fallen Wires

Stay away from fallen wires and warn others to keep away. Call us immediately. If a wire touches your vehicle, stay inside. However, if your car catches fire, jump clear of the car without touching the car's metal and the ground at the same time.

Indoor Electrical Fires

Without touching the appliance, unplug it or turn off the electric supply. Use a Class C rated fire extinguisher, if available. If one is not available, throw baking soda on the fire—never use water on an electrical fire. If necessary, call your fire department.

Portable Generators

Never use a generator indoors or in any enclosed space. Always use proper power cords and follow instructions. Do not overload the generator with more equipment than its output rating. Also make sure your generator is properly grounded.

Light Bulbs

Be sure to turn light switches off before changing bulbs. Use only bulbs of the appropriate wattage for the fixture.

Electric Cords and Outlets

Replace any frayed or damaged cords. Also use proper extension cords—heavy-duty cords for power tools and moisture-resistant cords for working outdoors. If you have children in your home, make sure to install safety plugs and outlet covers. Also, never plug too many cords into one circuit.

Tree Planting and Trimming

Trees should be kept a safe distance from all electrical wires. Call us for a free "Trees for Streets and Lawns" brochure to learn more.

Safety & Security Lighting Program

We can install outdoor lighting that automatically comes on at dusk and goes off at dawn. Adequate outdoor lighting improves visibility, reduces accidents, and deters burglars and vandals. Call us for more information.

Gas Line Safety

Safe habits go beyond the walls and foundation of your home. Follow these guidelines to avoid unnecessary damage to natural gas distribution lines, electric lines, and other utilities' facilities as you enjoy your home and property.

Aboveground Pipe Safety

You should never hang anything from aboveground pipes. The added weight can weaken or break pipe joints or fittings, resulting in a leak.

Underground Pipe Safety

Call 811 three business days before a digging project—it's the law. Whether you're doing a major excavation or minor landscaping, safeguard yourself from hazards related to damaging underground pipelines. A simple call gets all your public utility lines marked to help protect you from injury and costly property damage.

811

Know what's below.
Call before you dig.

What About Gas Lines Beyond the Meter?

We are responsible only for maintaining pipes that run up to and include the meter. All natural gas pipes on the property beyond the meter must be maintained by the property owner.

Before digging near buried natural gas pipes, locate the pipes and mark the area. To ensure the safety and soundness of the pipes and customer-owned fuel lines, periodically inspect them for leaks and corrosion and never hang anything from them.

Should you need assistance in locating, inspecting, or repairing pipes, you can contact your local plumber or heating contractor or call us.

Customer Choice Information

Under the Electric and Natural Gas Choice Program, you have the option to choose a third-party energy supplier. Regardless of which supplier you choose, you will receive the same level of service and reliability you already enjoy from us.

Choosing Another Supplier

While we cannot recommend suppliers or provide information on their pricing, you can look at your most recent bill for our current Price to Compare (see the sample bill on page 3) or check **www.ugi.com/price-to-compare.**

Questions you could ask third-party suppliers:

- What is your price per kWh of electricity or per CCF of natural gas? Does this price include transmission and state-mandated alternative energy costs?
- Is this rate fixed or can it change?
- Do I need to sign a contract? What is the length of the agreement?
- Are there penalties for switching or canceling?
- Will I get one bill or two? Do I have a choice?
- Are there restrictions on how much energy I can use or when I can use it?
- Do your quoted rates include taxes?
- Are there any other charges or fees?

For a list of licensed electric generation and natural gas suppliers, visit the sites below:

- For electric generation suppliers:
  www.ugi.com or **www.papowerswitch.com**.
- For natural gas suppliers:
  www.ugi.com or **www.pagasswitch.com**.

If you decide that another electric generation or natural gas supplier is right for you:

- Notify your chosen supplier. The supplier will send you a statement outlining the terms of your agreement. You may cancel your choice within three business days of receiving the statement.
  A penalty may apply if you do not remain with a supplier for the entire agreement period.
- Your chosen supplier will notify us.
- You will receive a letter from us confirming your choice. Please make sure that it is the correct supplier.

IMPORTANT: If you participate in the Customer Assistance Program (CAP) and you wish to choose a supplier, please contact us for assistance.

Your Rights and Responsibilities

The Pennsylvania Public Utility Commission (PUC) has updated its **Standards and Billing Practices for Residential Service**.

Your Rights and Responsibilities as a Utility Consumer is a booklet prepared by the PUC to explain the rules regarding a utility's billing, credit, dispute handling and shut-off practices.

This useful booklet also includes information about various payment options for your utility bill, understanding the components of your utility bill, policies regarding security deposits, steps and rules about utility shut-offs, and how to shop for electricity or natural gas service.

You'll find a copy of the Rights and Responsibilities booklet to review or print at **www.ugi.com.** We will continue providing you with safe and reliable utility service, clear and concise bills, and fair policies. You, the consumer, should know your rights and fulfill your responsibilities to maintain your service.

As a residential utility customer, you have the RIGHT to:

- Safe and reliable service.
- A clear, concise, and accurate bill.
- Fair credit and deposit policies.
- Know how your bill is calculated and how to tell if it is too high.
- Question or disagree with your utility company.
- Personal privacy. *UGI has the responsibility of safeguarding your personal information against unauthorized use.*

As a residential utility customer, you also have the RESPONSIBILITY to:

- Pay your bill on time.
- Provide us with access to your meter.
- Give UGI at least 7 days' notice before you move or wish to discontinue service. *If you fail to notify us, you remain responsible to pay the bills.*

Special Protections

You may qualify for special protections if you:

- Are a victim of domestic violence and have a Protection From Abuse Order.
- Live in a low-income household.
- Are seriously ill or a member of your household is seriously ill. You will be required to provide proof to your provider.

Billing

All UGI customers receive bills for electric service once during a regular billing cycle (approximately one month). Customers can enroll in a program (at www.ugi.com) to pay their bills online. Please refer to www.ugi.com and "Pay Bill Online" in the left center side of the page for a list of options.

Meter Readings

Each month on approximately the same date, meter readers are scheduled to read the electric meter at your residence. Meter readers and utility service personnel carry identification, which you may ask to see for your protection. UGI has moved to an Automated Meter Reading (AMR) system throughout most of our service territory. Using the AMR system, UGI is able to record meter readings by simply driving or walking by your home. Employees use devices known as ERTs (Encoder-Receiver-Transmitters) that allow them to obtain an accurate meter reading.

- Through Automated Meter Reading, monthly bill statements are based on actual meter reads and exact electric usage. Therefore, customers will no longer routinely receive estimated electric bills.

Welcome Home.

UGI Emergency Contact:
UGI Contacto de emergencia:

800-276-2722 - Customers of UGI Gas and Electric Service

Billing and Customer Inquiries:
800-276-2722
Customer Assistance Programs:
800-844-9276 (800-UGI-WARM)
For Hearing Impaired:
800-654-5988

Discover everything UGI does for homes and businesses at ***www.ugi.com***

Energy to do more®

Energy to do more®

Did you know that the Federal Poverty Income Guideline limits have increased for 2025?

If your household income is at or below these levels below, you could qualify for one or more of the UGI Customer Assistance Programs!

The New Federal Poverty Income Guidelines are in effect!

Monthly Household Income Limits

# of Household Members	150% FPL	200% FPL	250%FPL
1	$1,956	$2,608	$3,260
2	$2,644	$3,525	$4,406
3	$3,331	$4,442	$5,552
4	$4,019	$5,358	$6,698
5	$4,706	$6,275	$7,844
6	$5,394	$7,192	$8,990
Each additional person	$688	$917	$1,146

Programs Available:

Low Income Home Energy Assistance Program (LIHEAP)
Available at or below 150% FPL

LIHEAP helps families pay heating bills with a grant between the amount of $200 - $1,000. **This money does not have to be paid back and gets sent directly to UGI to pay your bill.** The program will close in April so apply now before it is too late!

Customer Assistance Program (CAP)
Available at or below 150% FPL

Avoid unpredictable utility bills and balance your household budget a little easier. Pay the same amount each month, based on the average bill at your property or a percentage of your total income. Average CAP customers only pay between 4- 6%* of their total gross income. You can also receive debt forgiveness and bill forgiveness each month with on-time payments.

**CAP percentage of income payments will vary based on customer's household income, type of service, and poverty level.*

Operation Share Grant
Available at or below 250% FPL

If you are struggling to pay your bill, apply for an Operation Share grant today. No need to wait. Grants do not have to be paid back and are funded by donations from your neighbors, UGI employees, and UGI Company to help families in need.

Low Income Usage Reduction Program (LIURP)
Available at or below 200% FPL

Is your home cold and drafty? Have you tried lowering the thermostat but have not seen a difference in your bill? Check out UGI's Low Income Usage Reduction Program (LIURP) available to homeowners and renters. We have contractors that will install energy efficient measures into your home at no cost to you! Most customers see an average of 20% reduction in their UGI bill.

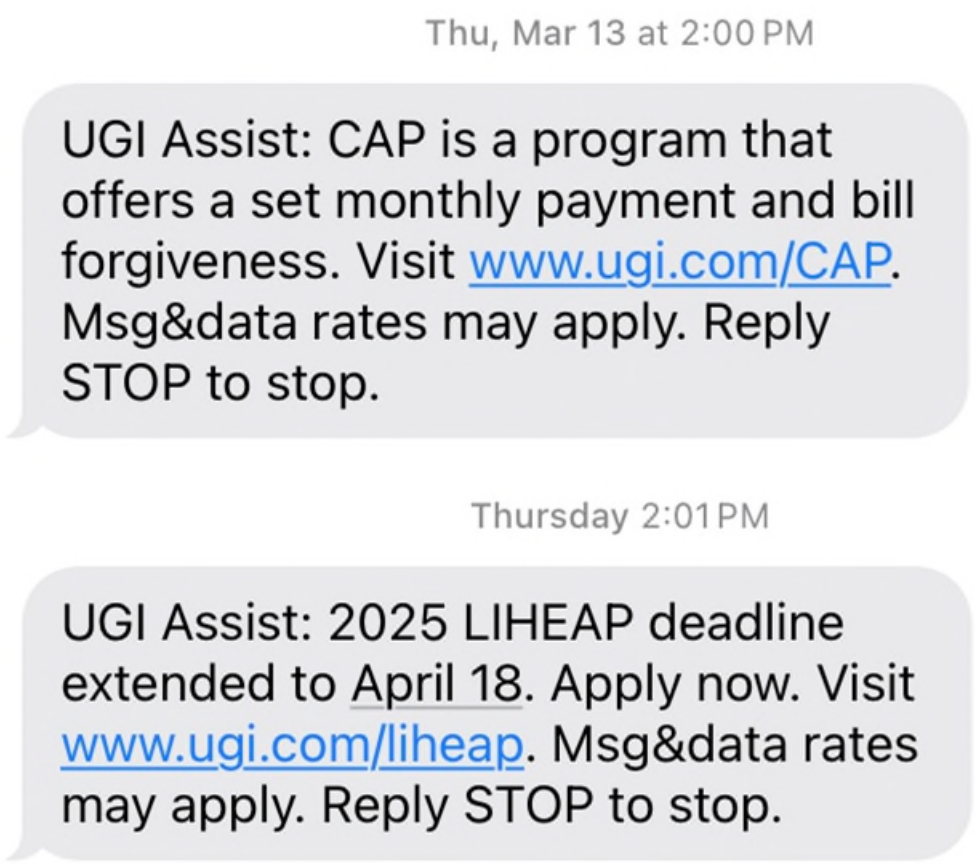
Interested in any of the above programs or want to learn more?

FILL OUT OUR QUICK ONLINE FORM

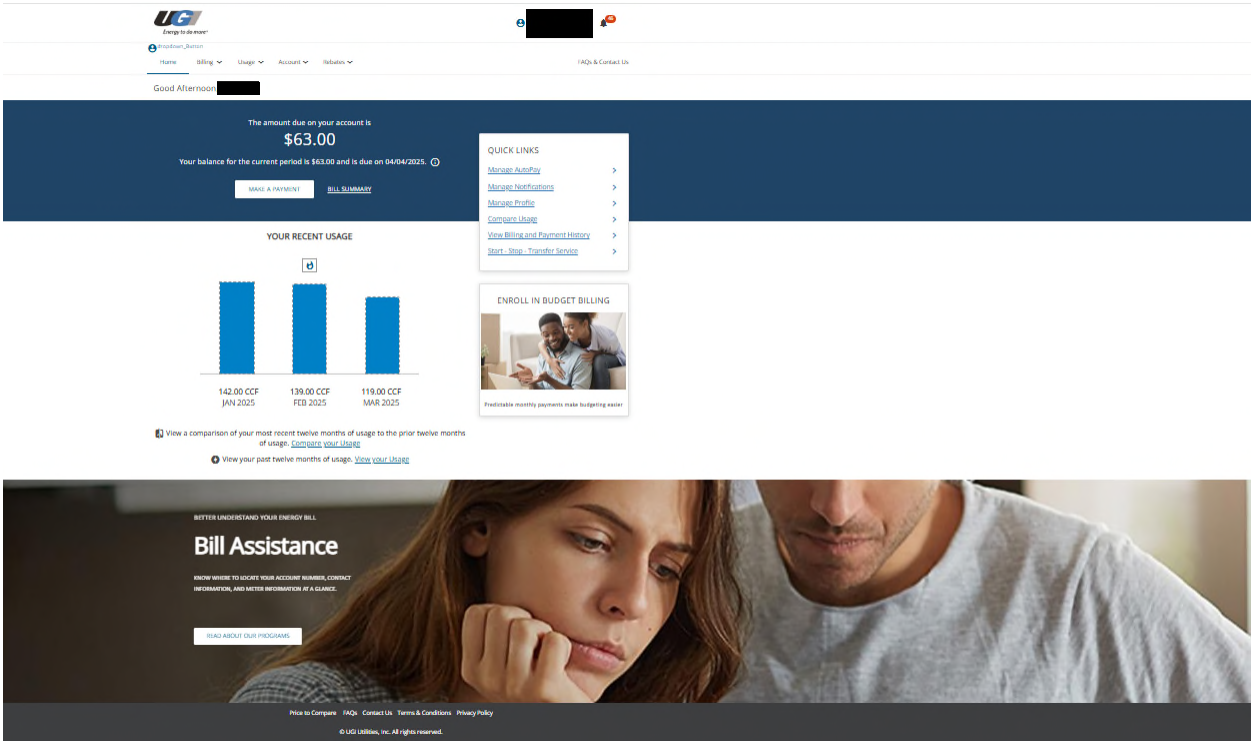
If you know of a UGI customer who could benefit from these programs, please pass along this information.

UGI está comprometida a ayudar a los clientes que hacen un esfuerzo sincero para pagar sus facturas. Nuestros representantes pueden ayudarlo al proporcionar información sobre diversos programas de asistencia energética, haciendo derivaciones a agencias locales, ofreciendo participación en fondos de combustible o estableciendo acuerdos de pago. Hay intérpretes de servicios de idiomas disponibles para ayudar por teléfono. Llame al 800-UGI-WARM u 800-844-9276 para obtener más información.

ASSISTANCE PROGRAMS | UGI IN OUR COMMUNITIES


Thu, Mar 13 at 2:00 PM
UGI Assist: CAP is a program that offers a set monthly payment and bill forgiveness. Visit www.ugi.com/CAP. Msg&data rates may apply. Reply STOP to stop.
Thursday 2:01 PM
UGI Assist: 2025 LIHEAP deadline extended to April 18. Apply now. Visit www.ugi.com/liheap. Msg&data rates may apply. Reply STOP to stop.

- Online Payment Portal: https://onlineaccount.ugi.com/portal/
    - Bill Assistance Programs (link on Online Payment Portal): https://www.ugi.com/assistance-programs/
- After sign in on Payment Portal, rotating ads appear at bottom of overview page (see below, first screen shot) and then on subsequent pages on right navigation, second screen shot)



Energy to do more®

[redacted] 46

Home | Billing | Usage | Account | Rebates | FAQs & Contact Us

Bill Summary

THE AMOUNT DUE ON YOUR ACCOUNT IS

$63.00

Your balance for the current period is $63.00 and is due on 04/04/2025.

MAKE A PAYMENT | ENROLL IN AUTOPAY

Set Your Billing Notification Preferences.

BILLING QUICK LINKS

Explore Customer Assistance Programs
Understand Your UGI Bill
View Billing and Payment History
AutoPay

BILL DETAILS

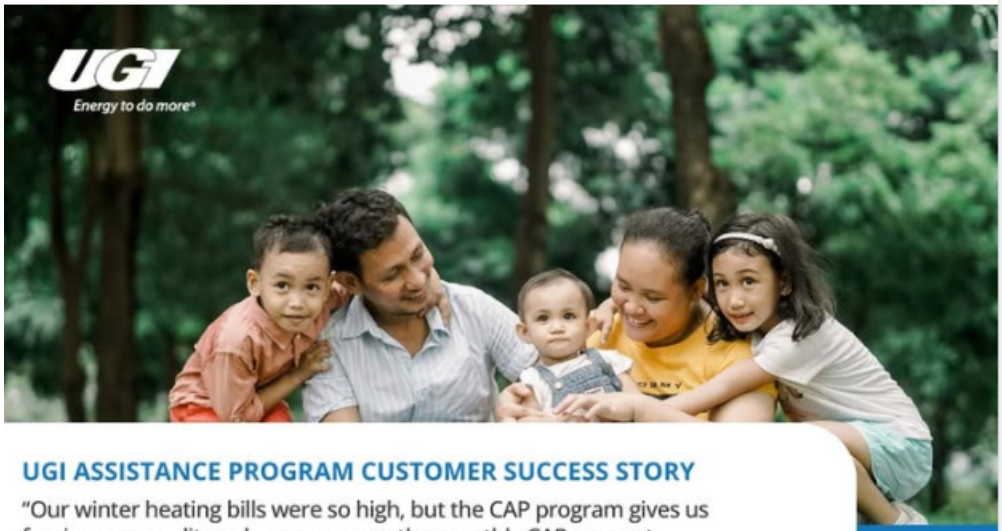
Billing Period	02/11/2025 to 03/13/2025
Past Due Balance (Pay Immediately)	$0.00

UGI Utilities, Inc.
January 9, 2024 ·
Energy to do more
UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY
"With the cost of everything rising I was finding it hard to make my monthly budget payments for my utility bill. My daughter told me about CAP and helped me enroll. My payments dropped from $150/month to only $49/month."
Dorthy S, UGI Customer
For more info, visit ugi.com/assistance

UGI Utilities, Inc.
January 23, 2024 ·

Participants of the Low-Income Usage Reduction Program (LIURP) see an average of 20% savings on their UGI bill after weatherization is complete. Find out if you qualify at https://www.ugi.com/assistance-programs/LIURP

UGI Utilities, Inc.
February 6, 2024 ·



UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"Our winter heating bills were so high, but the CAP program gives us forgiveness credits as long as we pay the monthly CAP amount.

Last month our heating bill was $425.00. Because we are on CAP we only needed to pay $73. UGI gave us the credit between the difference which is $352.00! Talk about saving on your bill! Thanks UGI."

The Westerly Family, UGI Customer

For more info, visit ugi.com/assistance

UGI Utilities, Inc.
February 20, 2024 ·

UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"I had to reduce my working hours when one of my kids got sick. Trying to keep up with all the expenses got tough. I like being on the CAP program because I know what my monthly payments are."

Andi M, UGI Customer

For more info, visit ugi.com/assistance

UGI Utilities, Inc.
March 1, 2024 ·

March is Social Work Month. UGI Utilities partners with Community Based Organizations to help customers enroll in income-based programs. Throughout March we will be highlighting agencies that administer UGI programs like:
*Operation Share – a grant to customers experiencing a hardship;
*CAP – Customer Assistance Program – a monthly payment based on household income;
*LIURP – installs energy saving measures in a home to make it more efficient.

UGI Utilities, Inc.
March 4, 2024 ·

This week, in honor of Social Work month, we want to thank agencies that administer our Customer Assistance Program (CAP). CAP is an income-based payment plan that provides debt forgiveness and account credits for each on-time payment; monthly payments are based on household income:

AGAPE Love From Above To Our Community
Agency for Community Empowerment of NEPA/ACE
The Salvation Army, Allentown Corps ... See more

UGI Utilities, Inc.
March 11, 2024 ·

This week, in honor of Social Work month, we want to thank agencies that assist with providing Operation Share grants to customers experiencing a hardship that prevents them from paying their utility bill:

AGAPE
The Salvation Army, Allentown Corps
Bethlehem Salvation Army... See more

UGI Utilities, Inc.
March 18, 2024 ·

This week, in honor of Social Work month, our focus is on LIURP, the Low Income Usage Reduction Program. LIURP agencies assist customers in obtaining energy saving measures like insulation, caulking, and other improvements to lower utility bills and make homes more comfortable year-round:

Agency for Community Empowerment
Berks Community Action Program
Carbon County Action Committee for Human Services ... See more

UGI Utilities, Inc.
March 25, 2024 ·

As we near the end of March, we want to take one more opportunity to say THANK YOU to all of the people that help us help our customers enroll in programs that provide assistance to those in need. We are proud to partner with agencies that administer UGI programs like:

*Operation Share – a grant to customers experiencing a hardship;

*CAP – Customer Assistance Program – a monthly payment based on household income;

*LIURP – installs energy saving measures in a home to make it more efficient

Program participation is voluntary, and total household income must be at or below federal poverty guidelines for each of the above programs. For additional information about our customer assistance programs, including income requirements for each, visit https://www.ugi.com/assistance-programs.

UGI Utilities, Inc.
April 2, 2024 ·

LIHEAP, the Low Income Home Energy Assistance Program, closes this Friday, April 5, 2024. LIHEAP provides grants to income-eligible residents of Pennsylvania. Learn more at https://www.ugi.com/assistance-programs/LIHEAP

UGI Utilities, Inc.
April 8, 2024 ·

If you are behind on your utility bills, UGI is here to help! Visit https://www.ugi.com/here-to-help to learn more.

UGI Utilities, Inc.
April 10, 2024 ·

UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"My wife and I both have jobs but our income for a family of 5 is under $54,870 which means we (thankfully!) qualified for the UGI Customer Assistance Program (CAP). It has helped us manage our monthly bills better because our monthly bill is based on our income. And - bonus - the past due amount we had when we enrolled will disappear in 3 years!"

DK, UGI Customers

For more info, visit ugi.com/assistance

UGI Utilities, Inc.
April 12, 2024 ·

The PA Homeowner Assistance Fund (PAHAF) reopened March 18, 2024, and new applicants may apply for assistance. Per the PAHAF website, "Funds will be distributed on a first-come, first-served basis to eligible applicants until the remaining monies are exhausted with priority given to homeowners facing an imminent adverse action (IAA) such as a notice of foreclosure, sheriff sale or utility shut-off notice." Learn more at

PAHAF.ORG

Pennsylvania Homeowner Assistance Fund

The Pennsylvania Homeowner Assistance Fund is a housing-related program that...

UGI Utilities, Inc.
April 18, 2024 ·

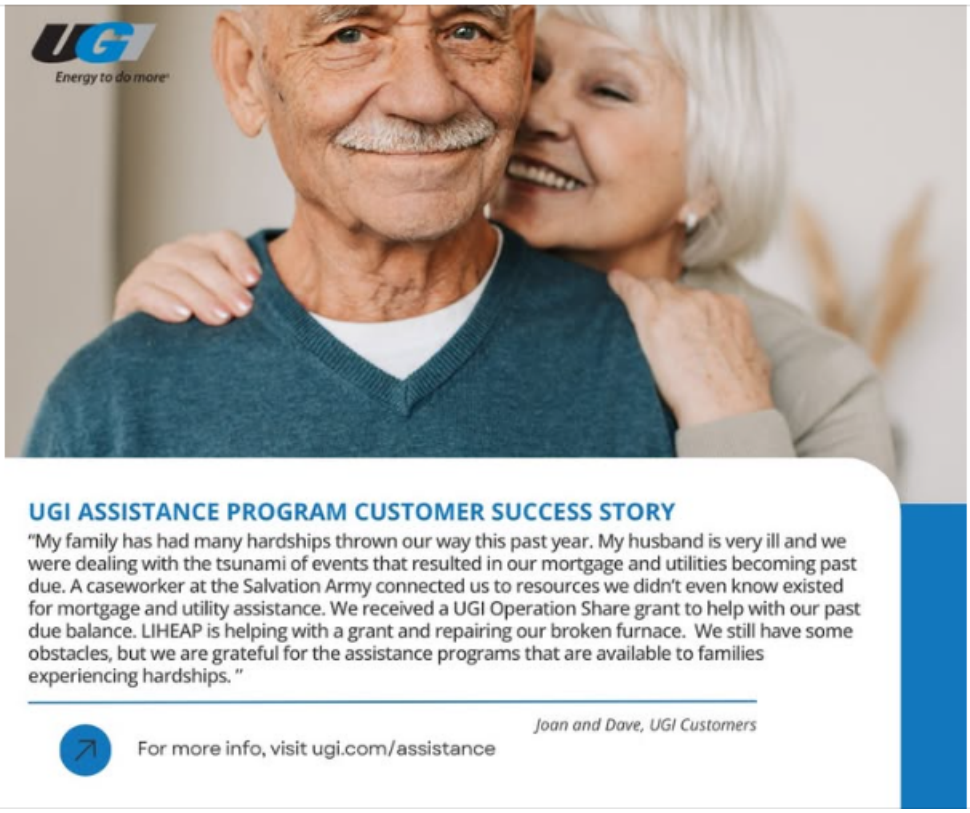
UGI OPERATION SHARE GRANT RECIPIENT

"I want to express my sincere appreciation for granting me this help in paying my natural gas expense for 2023. I expect and am receiving pretty high bills associated with my hip surgery. THIS GRANT PAID BY FRIENDS AND EMPLOYEES is so appreciated.

My heart felt THANKS TO YOU."

R.D., UGI Customer

UGI Utilities, Inc.
April 24, 2024 ·



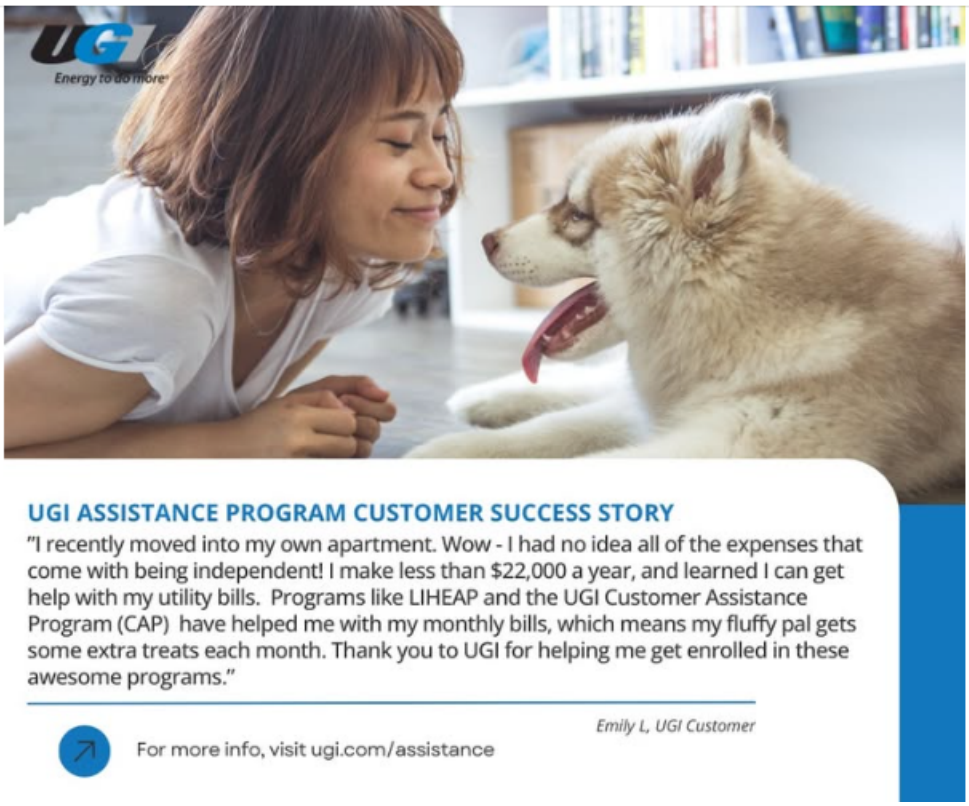
UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"My family has had many hardships thrown our way this past year. My husband is very ill and we were dealing with the tsunami of events that resulted in our mortgage and utilities becoming past due. A caseworker at the Salvation Army connected us to resources we didn't even know existed for mortgage and utility assistance. We received a UGI Operation Share grant to help with our past due balance. LIHEAP is helping with a grant and repairing our broken furnace. We still have some obstacles, but we are grateful for the assistance programs that are available to families experiencing hardships."

Joan and Dave, UGI Customers

For more info, visit ugi.com/assistance

UGI Utilities, Inc.
April 30, 2024 ·



UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"I recently moved into my own apartment. Wow - I had no idea all of the expenses that come with being independent! I make less than $22,000 a year, and learned I can get help with my utility bills. Programs like LIHEAP and the UGI Customer Assistance Program (CAP) have helped me with my monthly bills, which means my fluffy pal gets some extra treats each month. Thank you to UGI for helping me get enrolled in these awesome programs."

Emily L, UGI Customer

For more info, visit ugi.com/assistance

UGI Utilities, Inc.
May 23, 2024 ·

UGI ASSISTANCE PROGRAM CUSTOMER SUCCESS STORY

"We learned about CAP, the UGI Customer Assistance Program, from a neighbor. We went from a two-income family, to a one-income family in the blink of an eye. Enrolling in CAP means our monthly UGI payment went from $200 a month to $75 a month. Talk about a reason for a family high five!"

M.J. Brown, UGI Customer

For more info, visit ugi.com/assistance

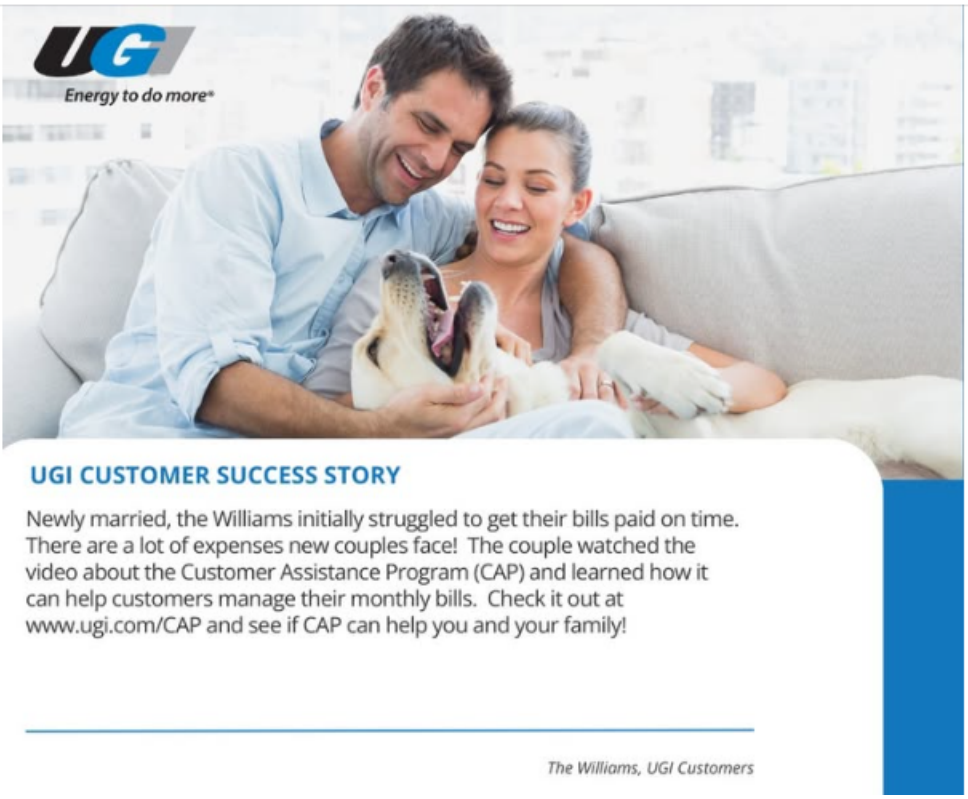
UGI Utilities, Inc.
May 28, 2024 ·

The Customer Assistance Program (CAP) sets you up on an affordable fixed monthly payment, monthly bill credits, and debt forgiveness if you have a past due balance. See if you qualify and download an application at www.UGI.com/CAP

UGI Utilities, Inc.
June 18, 2024 ·

Everybody struggles to pay bills now and then. If you are falling behind on your payments, please check www.ugi.com/assist.

UGI Utilities, Inc.
July 9, 2024 ·



UGI CUSTOMER SUCCESS STORY

Newly married, the Williams initially struggled to get their bills paid on time. There are a lot of expenses new couples face! The couple watched the video about the Customer Assistance Program (CAP) and learned how it can help customers manage their monthly bills. Check it out at www.ugi.com/CAP and see if CAP can help you and your family!

The Williams, UGI Customers

UGI Utilities, Inc.
July 11, 2024 ·

Need help understanding your utility bill? We can break it down for you.
https://www.ugi.com/payments.../your-ugi-bill-explained/

UGI Utilities, Inc.
July 16, 2024 ·

We're all in this together! If you are struggling to pay your UGI bill, we want to help. We have several different assistance options to help our customers. Explore our programs and see what is right for you: https://www.ugi.com/assistance-programs/

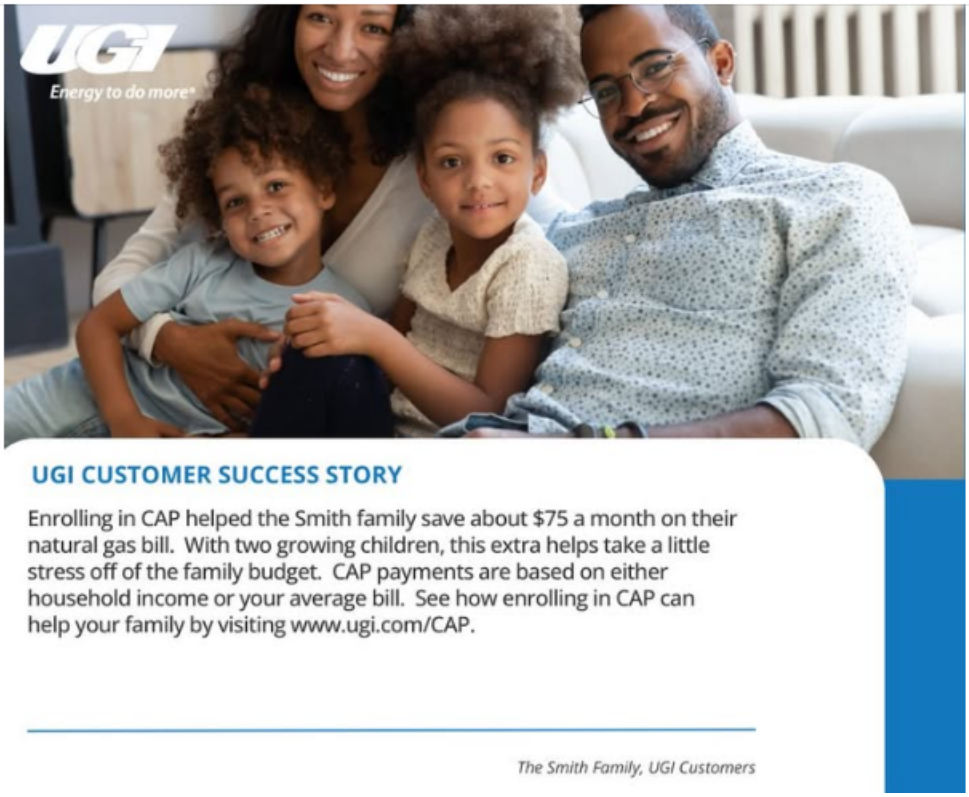
UGI Utilities, Inc.
July 23, 2024 ·

UGI just helped a family save over $100/month on their UGI bill by enrolling in the Customer Assistance Program (CAP). CAP offers an affordable monthly payment and debt forgiveness. Download an application and follow the instructions listed here www.ugi.com/cap

UGI Utilities, Inc.
August 6, 2024 ·

Learn about CAP, the UGI Customer Assistance Program, by watching our short informational video. The video is available in English and Spanish. CAP is an income-based payment plan that provides debt forgiveness and bases your monthly payment on your income or average bill. Learn more by viewing the video at https://www.ugi.com/assistance-programs/CAP/.

UGI Utilities, Inc.
August 9, 2024 ·



UGI CUSTOMER SUCCESS STORY

Enrolling in CAP helped the Smith family save about $75 a month on their natural gas bill. With two growing children, this extra helps take a little stress off of the family budget. CAP payments are based on either household income or your average bill. See how enrolling in CAP can help your family by visiting www.ugi.com/CAP.

The Smith Family, UGI Customers

UGI Utilities, Inc.
July 30, 2024 ·

UGI CUSTOMER SUCCESS STORY

Betty and John had some unexpected medical expenses that caused them to fall behind on their utility bills. They contacted UGI and were able to enroll in CAP. Their monthly payment decreased by $125 a month, and the amount they were behind will be forgiven after they make on-time payments for 36 months.

Betty and John, UGI Customers

UGI Utilities, Inc.
August 6, 2024 ·

Learn about CAP, the UGI Customer Assistance Program, by watching our short informational video. The video is available in English and Spanish. CAP is an income-based payment plan that provides debt forgiveness and bases your monthly payment on your income or average bill. Learn more by viewing the video at https://www.ugi.com/assistance-programs/CAP/.

UGI Utilities, Inc.
August 14, 2024 ·

We all have experienced financial hurdles and sometimes need help getting back on track. If you're struggling to make your monthly utility bill payments, please visit https://www.ugi.com/assistance-programs/. We have programs that may help!

UGI Utilities, Inc.
August 20, 2024 ·

Back to school means cooler weather will be here soon. If you're sweating over how to pay your monthly expenses, check out our Assistance Programs at https://www.ugi.com/assistance-programs/. Learn how programs for income-qualified customers can help you better manage energy bills.

UGI Utilities, Inc.
August 27, 2024 ·

UGI Utilities employees are proud to help local students start the new school year on the right foot! Employees recently helped to stuff backpacks with school supplies in preparation for The Salvation Army, Allentown Corps' Backpack Giveaway & Community Street Fair. Employees also attended the event to distribute school supplies, refreshments, and customer program information to over 1,000 students and their families.

UGI Utilities, Inc.
August 28, 2024 ·

Sometimes life events prevent us from handling routine tasks like paying bills. If you have fallen behind on your UGI bill, don't put off trying to get back on track. We have programs to help, including our income-based Customer Assistance Program for households at, or below, 150% of the Federal Poverty Level. Learn more at https://www.ugi.com/here-to-help

UGI Utilities, Inc.
September 4, 2024 ·

Did you receive a grant from LIHEAP in the last 12 months? Then we've got some GOOD NEWS! You are eligible for UGI's Customer Assistance Program (CAP). CAP is an income-based payment plan that can help you better manage your monthly bills. Visit https://www.ugi.com/assistance-programs/cap/ to learn more about CAP.

UGI Utilities, Inc.
October 8, 2024 ·

CAP is UGI's Customer Assistance Program. It helps residential customers with a set monthly payment based on income, monthly bill credits, and forgiveness on past due balances. Learn more and see if you qualify at https://www.ugi.com/assistance-programs/CAP/

UGI Utilities, Inc.
September 17, 2024 ·

Heating season is around the corner. The Low Income Home Energy Assistance Program will be opening in November. (Even if you received LIHEAP previously, you still need to apply this year to get a grant this heating season.) New on this year's LIHEAP application is a question about if you want DHS to share your data with local utilities. Checking this box makes it even easier to qualify for other utility assistance programs.

UGI Utilities, Inc.
October 16, 2024 ·

The Low Income Home Energy Assistance Program (LIHEAP) will be taking applications soon! Even if you received LIHEAP grants in the past, you need to reapply each year. Learn more at https://www.ugi.com/assistance-programs/LIHEAP. This year, there's a new checkbox on the LIHEAP application. It asks if you want to share information from the application with your utility company. Checking that box means utilities may be able to assist you with enrollment into other programs that can help you each month!

Learn more at https://ugi.reportablenews.com/.../ugi-reminds-eligible...

UGI Utilities, Inc.
October 18, 2024 ·

Winter weather is right around the corner. If you've had your natural gas service shut off, be sure to reach out to restore service before it gets colder. For more information on payment arrangements and customer programs, visit https://www.ugi.com/here-to-help/.

UGI Utilities, Inc.
October 28, 2024 ·

Our Free Energy Assistance Event for UGI Customers in Lancaster, PA is October 29. UGI representatives will be at the Community Action Partnership (CAP), 601 South Queen Street, Lancaster, PA. For more information, including what to bring to the event and dates and locations of future in-person events, visit https://www.ugi.com/energy-assistance-event/

UGI Utilities, Inc.
December 9, 2024 ·

The Customer Assistance Program (CAP) is an income-based payment plan that offers benefits like a fixed monthly payment, monthly bill credits, and debt forgiveness if you have a past due balance. See if you qualify and request an application at www.UGI.com/CAP.

UGI Utilities, Inc.
December 17, 2024 ·

Operation Share is a grant that can help people through a temporary hardship and help keep their family and homes warm all winter. Learn more, including how to apply or donate, at https://www.ugi.com/assistance-programs/operation-share/.

UGI Utilities, Inc.
January 16, 2024 ·

Did you receive a grant from LIHEAP this season? If so, enrolling in UGI's CAP just got easier! Customers who received a LIHEAP grant towards their UGI account can enroll in UGI's CAP program over the phone! Learn about CAP and all the benefits you could receive at www.ugi.com/CAP.

LOW INCOME USAGE REDUCTION PROGRAM (LIURP)

UGI's LIURP offers free weatherization measures to qualified low-income residential heating customers in order to limit heat loss and provide long-term energy savings. These energy savings measures may include window and baseboard caulking, door and window weather-stripping, attic and sidewall insulation, duct and pipe insulation, ventilation, water conservation devices, furnace inspections and energy education.

In addition, non-heating UGI Electric accounts may qualify for measures such as refrigerator replacement and high-efficiency lighting.

LIURP ELIGIBILITY CRITERIA

To be eligible the customer must have: (1) an active UGI gas or electric heating account with twelve (12) or more continuous billing periods for the same account number; (2) higher than average gas or electric heating usage during the twelve month period to meet specified consumption levels for the program; (3) renters can qualify with written permission from landlords; (4) Gross Annual Income must be at or below 150% of the Federal Poverty Level *(see insert for details)*. A percentage of customers who may have extenuating circumstances can be accepted at 200% of Federal Poverty Level.

One additional LIURP program called the UGI Rehabilitation Program is designed to take a proactive approach to install approved energy efficient measures at the time of new construction or rehabilitation. Email **liurpteam@ugi.com** for more information.

CONTINUED ON BACK PANEL

CUSTOMER ASSISTANCE REFERRALS EVALUATION SERVICES (C.A.R.E.S.)

C.A.R.E.S. provides referrals to other helpful programs in your community. UGI will send any customer, regardless of income, a Customer Assistance Guide and energy-related information specifically for your area. In addition to LIHEAP and LIURP, these programs can include budget counseling or Office of Aging programs.

C.A.R.E.S. ELIGIBILITY CRITERIA

Customer must be a residential customer experiencing a temporary personal or financial crisis.

Additional Services offered by UGI:

- **Conservation literature**
- **Gift credits**
- **Third party notification**
- **Online bill pay**
- **Budget billing**
- **Payment arrangements**
- **Extended due date**

Energy to do more®

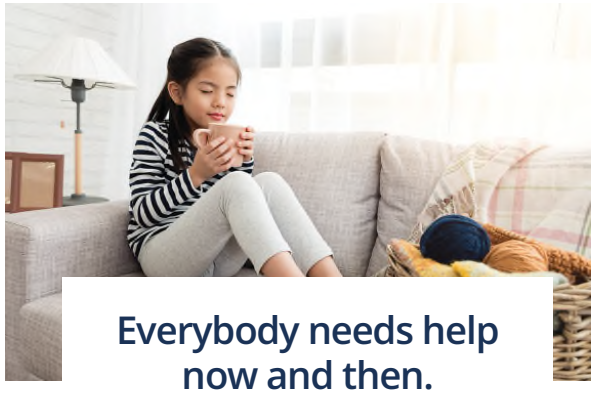
www.ugi.com

Universal Services

PROGRAMS

For more information please call:
800 UGI-WARM
800 844-9276

To learn more or enroll visit www.ugi.com/electrichelp



Everybody needs help now and then.

We want to help guide you through the many programs available to help customers manage their energy bills. Look at the table below and select the option that best describes your situation, then look at the Program you should start with.

Your Current Situation	Start With This Program
You have no heat, or an active termination notice, and limited income. (Note: Enrollment for this program occurs in early November of each year and ends in April the following year.)	Low Income Home Energy Assistance Program (LIHEAP)
You have high debt, and need help managing monthly energy bills. You want "forgiveness" of utility debt as long as you continue to make on-time payments to UGI for 3 years.	Customer Assistance Program (CAP)
You have a temporary hardship (death of wage earner, loss of job, sickness, etc.) that prevents you from paying your utility bills.	Operation Share
Your home is cold and drafty, and keeping the thermostat low doesn't result in lower energy bills.	Low Income Usage Reduction Program (LIURP)

LOW INCOME HOME ENERGY ASSISTANCE PROGRAM (LIHEAP)

LIHEAP (Low Income Home Energy Assistance Program) is a federally funded program administered by each state that helps low income households pay their heating bills through energy assistance grants. There are two components to the LIHEAP program: CASH and CRISIS.

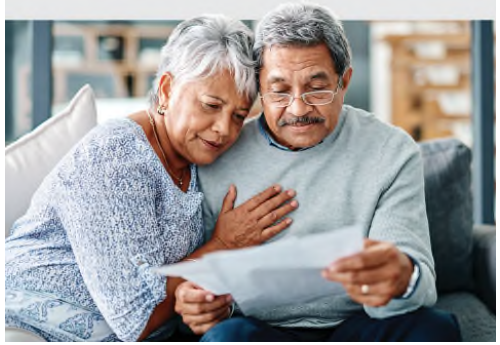
ELIGIBILITY FOR CASH GRANT

A customer must be responsible for home heating costs. CASH grants are applied directly to your account. This is not a loan and the money does not have to be paid back.

ELIGIBILITY FOR CRISIS GRANT

CRISIS grants help families who are in danger of being without heat due to situations like:

- **Utility services shut-off**
- **Active termination notice**
- **Broken heating equipment or leaking fuel lines**



Homeowners or renters whose gross annual income meets the income guidelines (see insert for details) established for the program by the State are eligible.

To apply, a customer must have a recent heating bill, and the names, Social Security numbers, and proof of income for all household members.

For more information regarding this program, customers can contact UGI or their local County Assistance Offices (**www.ugi.com/CAO**).

CUSTOMER ASSISTANCE PROGRAM (CAP)

UGI's Customer Assistance Program (CAP) benefits include:

- **A personalized monthly payment based on income and average bill;**
- **Past due debt forgiveness with on time monthly payments;**
- **The difference between the CAP payment and the actual usage bill may also be forgiven.**

UGI partners with local community agencies to provide this useful program to customers.

CAP ELIGIBILITY CRITERIA

To be eligible, a customer must: (1) have household gross income at or below 150% of Federal Poverty Level; (2) be a residential customer with active energy service. Income Guidelines change annually, see insert for details.

OPERATION SHARE

The Operation Share program provides energy assistance grants to qualified customers who experience difficulty paying their heating bills. This community-based program is funded by voluntary donations from UGI employees, UGI customers, and concerned citizens. In addition, UGI provides a corporate donation to help fund the program.

OPERATION SHARE ELIGIBILITY CRITERIA

To be eligible the customer must: (1) have an active UGI account; (2) have gross income (see insert for details) at or below 200% of Federal Poverty Level; (3) have not received an Operation Share grant within the past twelve (12) month period.

Self-Reported Low income Journey.

Energy to do more®

Dear Raymond Brooks,

Based on information you previously provided to us, you may qualify for enrollment in the UGI Customer Assistance Program (CAP) for account [redacted].

Enrollment in the CAP Program will assist you in managing your monthly energy bill, is free and has no impact on your credit score.

You are eligible for enrollment in CAP if your income is at or below the income guidelines shown below.

Customer Assistance Program (CAP) Income Guidelines

Household Members	Annual Income	Monthly Income	Weekly Income
1	$21,870	$1,823	$421
2	$29,580	$2,465	$569
3	$37,290	$3,108	$717
4	$45,000	$3,750	$865
Additional People	+$7,710/person	+$643/person	+$148/person

If you are eligible and interested, please:

1. Download the CAP application.
2. Print and complete the application.
3. Return application with proof of income to your local Community Based Organization (CBO): [redacted]

We are also mailing an application to you through U.S. Postal Service.

If you do not have a printer, you can visit the CBO listed above and they will provide an application for you.

Enrolling in CAP presents many benefits, including having a set monthly payment based on a percentage of income or the average bill at your property (whichever is lower). The percentage of income is between 4% and 9% for a heating customer. Additional benefits include bill forgiveness and forgiveness of past due balances.

Please note you must pay the CAP-Enrolled Monthly Payment on-time, each month and provide updated income annually in order to remain enrolled in the program. We also encourage CAP customers to apply for LIHEAP each year.

Sincerely,

UGI Customer Assistance Team

ASSISTANCE PROGRAMS | UGI IN OUR COMMUNITIES

This email was sent by: UGI Utilities Inc
PO Box 13009, Reading, PA, 19612-3009 US

Privacy Policy

Update Profile **Manage Subscriptions** **Unsubscribe**

Text Message Campaign

Text ASSISTANCE to 844-84 to receive enrollment reminders and more via text alerts.

Programs like LIHEAP and CAP require customers to reapply or recertify each year. By opting into UGI Assistance text alerts, you'll receive these enrollment

reminders, plus more information and updates on the programs that may be available to you.

Text ASSISTANCE to 844-84 to Sign Up!

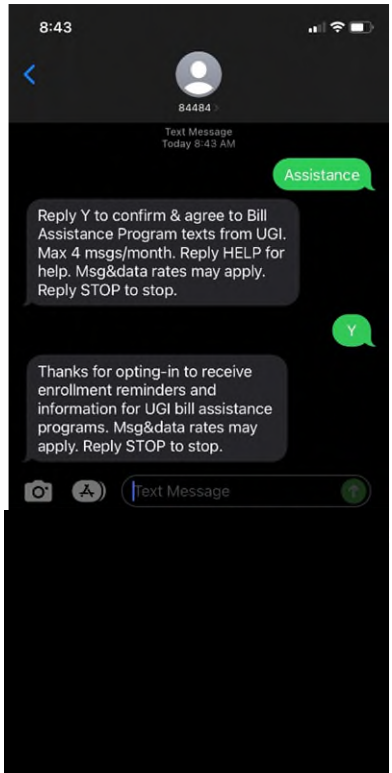
Messages and data rates may apply. Reply HELP for help. Text STOP to stop. Terms and Conditions at https://www.ugi.com/sms-terms-conditions/.

NATURAL GAS SAFETY | ELECTRIC SAFETY

This email was sent by: UGI Utilities Inc
PO Box 13009, Reading, PA, 19612-3009 US

Privacy Policy

Update Profile **Manage Subscriptions** **Unsubscribe**



New CAP Enrollment Journey

To view this email as a web page, go here.

Energy to do more®

Dear [redacted],

Thank you for participating in UGI Utilities Customer Assistance Program (CAP). Your enrollment has been accepted for Account # [redacted].

Here is what you can expect from CAP:

1. Reduced monthly payment
2. Bill forgiveness (difference between your actual monthly bill and what you pay on CAP)
3. Debt forgiveness (portion of past due balance forgiven every month)

Here are few tips to manage your monthly CAP agreement:

1. Make your monthly CAP payments on time
2. Notify your Community Based Organization (CBO) of any changes to your income or household size
3. Watch for a new application and recertify in 11 months

Sincerely,

UGI Customer Assistance Team

ASSISTANCE PROGRAMS | UGI IN OUR COMMUNITIES

This email was sent by: UGI Utilities Inc
PO Box 13009, Reading, PA, 19612-3009 US

Privacy Policy

Energy to do more®

Based on information in our system, your household income may qualify for LIHEAP If you've completed the LIHEAP application for the 2024-2025 season already, great! You're one step closer to receiving $200 (or more*) towards your winter heating bills.

If you haven't completed the form or applied online, we would like to assist you to make this process as simple as possible.

Click the button below to apply through COMPASS, the state website to help you receive LIHEAP funding.

APPLY FOR LIHEAP THROUGH COMPASS

About LIHEAP

The Low Income Home Energy Assistance Program (LIHEAP) is a federally funded program that helps pay heating bills through energy assistance grants*. The grants do not need to be paid back. Grants are applied directly to your utility account. You can apply online through the Pennsylvania state's COMPASS website.

Income Guidelines

Household Members	Annual Income	Monthly Income	Weekly Income
1	$22,590	$1,883	$434
2	$30,660	$2,555	$590
3	$38,730	$3,228	$745
4	$46,800	$3,900	$900

For additional person, add $8,070 per person annual income, $673/person monthly income or $155/weekly income.

*Minimum LIHEAP CASH grant is $200, with $1,000 maximum.

More Savings Could Be Available Through LIURP

Are your energy bills high even though your thermostat is set at a low temperature? The UGI Low Income Usage Reduction Program (LIURP) offers free weatherization measures to qualified low-income residential heating customers in order to limit heat loss and provide long-term energy savings. These energy savings measures may include window and baseboard caulking, door and window weather-stripping, attic and sidewall insulation, duct and pipe insulation, ventilation, water conservation devices, furnace inspections and energy education. Learn More

Have Questions? We're here to help!

If you have questions about any of the Customer Assistance Programs available to UGI customers please contact us Assistance@ugi.com.

Thank you for allowing us the opportunity to serve you!

UGI Customer Service Team

Phone Dialer Script:

- If human voice detected:
  - *Hello this is UGI Utilities, calling to speak with a current adult occupant at [Service Address]. If we have reached a current adult occupant, please press '1' now. If you are not a current adult occupant at [Service Address] please press '2' now. Please press '3' to reply this message.*
    - [IF 1]: *LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Our records indicate that you received a LIHEAP grant during the 2023-24 heating season for account [Account #] with a service address of [Service Address] in [Service City]. You may qualify for additional funds through LIHEAP CRISIS, which is for customers who are in jeopardy of losing their heat. If you would like UGI Utilities to apply for additional funds for you on your behalf, press 1 now. If you do not want UGI Utilities to apply for additional funds, press 2 now. <Repeat 1 time>*
      - [IF 1] *Thank you for our response. UGI Utilities will apply for additional funding on your behalf and you may disregard the upcoming mailing regarding this offer.*
      - [IF 2] *Thank you for our response. UGI Utilities will not apply for additional funding on your behalf. You may also receive an upcoming mailing regarding this offer.*
    - [IF 2]: *Please have an adult occupant call UGI at 1-800-844-9876. Thank you and have a nice day.*
- If machine voice detected:
  - *Hello this is UGI Utilities calling with important information regarding your account. Please call us at 1-800-844-9876 to hear about additional customers programs that you may qualify for. <Repeat 1 time>*

Conservation Packet Contents and Example

- Outside Envelope alerting customers to what's inside
- Adult coloring book (energy saving tips)
- Child "Sparky" coloring book
- Magnet with contact information
- Safety – "Smell Gas" steps
- Energy Saving Tips brochure
- One page contains information about all programs & translated content that help is available and how to get help

Energy to do more®

[redacted]

«Customer_Name»
«Mailing_Address__House__and_Street_Add»

«Mailing_Address__City» «Mailing_Address__State» «Mailing_Address__Zip_Code»

Dear «Customer_Name»,

Based on information you previously provided to us, you may qualify for enrollment in the UGI Customer Assistance Program (CAP) for account «Contract_Account_ID». Enrollment in the CAP Program will assist you in managing your monthly energy bill, is free and has no impact on your credit score.

You are eligible for enrollment in CAP if your income is at or below the income guidelines shown below. If you are eligible and interested in enrolling in the UGI Customer Assistance Program, please complete the attached CAP Application, and return it with proof of income to: [redacted]

Customer Assistance Program (CAP) Income Guidelines 2024

Household Members	Annual Income	Monthly Income	Weekly Income
1	$22,590	$1,883	$434
2	$30,660	$2,555	$590
3	$38,730	$3,228	$745
4	$46,800	$3,900	$900
Additional People	+$8,070 / person	+$673 / person	+$155 / person

If you enroll in CAP you could benefit from having a set monthly payment based on a percentage of income or the average bill at your property (whichever is lower). The percentage of income is between 4% and 9% for a heating customer. Additional benefits include bill forgiveness and forgiveness of past due balances.

Please note you must pay the CAP-Enrolled Monthly Payment on time, each month, and provide updated income annually in order to remain enrolled in the program. We also encourage CAP customers to apply for LIHEAP each year.

Thank you for being a customer of UGI.

UGI Customer Outreach Team

Energy to do more®

UGI Customer Assistance Program
CAP Application

Customer Name: «Customer_Name»

Account Number: «Contract_Account_ID»

Energy provided by UGI: ❑ Gas ❑ Electric ❑ Both Gas & Electric

For Service at: «Service_Address__House__and_Street_Ad» in «Service_Address__City»

Home Phone: _____ **Cell Phone:** _____ **Email:** _____

Household Members and Income — List the people who live with you at this address. Include all children and adults. Indicate all sources of income for each household member (state monthly income)

Name	SS#	Date of Birth	MJF	Income Source(s)	Income Amount(s)
Please attach additional sheets if necessary.				**Total Gross Monthly Income**	**$**

Household Expenses — Indicate all expenses for your household:

Expense	Amount	Expense	Amount
Mortgage/Rent		Food (without food stamps)	
Water/Sewer		Electric	
Transportation		Insurance	
Medical/Prescriptions		Telephone	
Day Care/Support		Trash/Recycling	
Non-Gas/Electric Heating			

Customer Assistance Program (CAP) CONSENT AND RELEASE

I agree and consent to UGI sharing the information contained in my application and all other information relating to my customer account with those employees, representatives, agents, contractors, or subcontractors of UGI utilized to administer CAP and to evaluate my application for acceptance into CAP. Furthermore, I hereby release and hold harmless UGI, its employees, representatives, agents, contractors, and affiliates from and against any and all claims related to my application, my participation in CAP, and the administration and evaluations of UGI CAP.

Customer Assistance Program (CAP) TRUTH OF STATEMENT

The information on this application is true and complete to the best of my knowledge. The employees, representatives, agents, contractors or subcontractors of UGI have the right to verify my income and expenses if necessary. I understand and accept that providing false or incomplete statements on this application will constitute cause for rejecting my application or removing me from CAP.

Signature: _____

Print Name _____Date _____

Permission to Contact

Do we have permission to contact you regarding your account? (Circle all that apply)

Home Phone Cell Phone Email

Application Instructions

- Fill out all required information clearly and completely
- Provide proof of income for the most recent 30 days, 90 days, or 12-month period. Proof includes letters, pay stubs, award, employer statements, etc.
- Provide a valid picture ID
- Make sure you have signed the CAP Consent and Release
- Make sure you have signed the CAP Truth of Statement
- Return the application to: [redacted]

If you told us you have no income or your income is less than the cost of your monthly expenses you may be required to provide additional information. Properties that have higher than average usage will be required to fill out additional forms.

Energy to do more®

[redacted]

Based on information you previously provided to us, you may qualify for enrollment in the UGI Customer Assistance Program (CAP) for account [redacted]. Enrollment in the CAP Program will assist you in managing your monthly energy bill, is free and has no impact on your credit score.

You are eligible for enrollment in CAP if your income is at or below the income guidelines shown below.

Customer Assistance Program (CAP) Income Guidelines

Household Members	Annual Income	Monthly Income	Weekly Income
1	$21,870	$1,823	$421
2	$29,580	$2,465	$569
3	$37,290	$3,108	$717
4	$45,000	$3,750	$865
Additional People	+$7,710 / person	+$643 / person	+$148 / person

If you are eligible and interested, please:

- Download a CAP Application
- Print and complete the application
- Return the application with proof of income to your local Community Based Organization (CBO): [redacted]

If you do not have a printer, you can visit the CBO listed above and they will provide an application for you.

Enrolling in CAP presents many benefits, including having a set monthly payment based on a percentage of income or the average bill at your property (whichever is lower). The percentage of income is between 4% and 9% for a heating customer. Additional benefits include bill forgiveness and forgiveness of past due balances.

Please note you must pay the CAP-Enrolled Monthly Payment on time, each month, and provide updated income annually in order to remain enrolled in the program. We also encourage CAP customers to apply for LIHEAP each year.

Energy to do more®

UGI Utilities, Inc.
225 Morgantown Road
Post Office Box 13009
Reading, PA 19612-3009

November 14, 2023

[redacted]

Customer Number: 4[redacted]

Dear [redacted],

Your CAP recertification is due within 30 days. This process will confirm your continued eligibility to remain on the program. The CAP recertification process includes providing household occupant information, current proof of income for all household members and a valid photo identification.

For your convenience, UGI has enclosed a recertification application. Please mail the completed application and your supporting documents to Harrisburg Salvation Army at 506 S 29th St Harrisburg, PA 17104. If you need assistance in completing this application, please call (717)233-6755.

Failure to recertify and verify your current income within 30 days may result in removal from program and loss of CAP benefits which include:

- Personalized monthly CAP amount (based on income or average bill)
- CAP credits (difference between billed usage and CAP amount)
- Forgiveness of past due debt

If you have any questions about your CAP bill, please call UGI at 1-800-276-2722.

We look forward to your continued participation in CAP.

Sincerely,

UGI Customer Outreach Department

Si necesita ayuda para pagar su factura de UGI o desea obtener más información sobre los programas disponibles que pueden ayudarlo con su factura de servicios públicos, comuníquese con UGI al (800) 276-2722. UGI cuenta con intérpretes disponibles, sin costo adicional.

UGI Utilities, Inc.
225 Morgantown Road
Post Office Box 13009
Reading, PA 19612-3009

November 14, 2023

[redacted]

Customer Number: 4[redacted]

Dear [redacted],

Your CAP recertification is now due. In order to remain enrolled in the program, you must recertify. The CAP recertification process includes providing household occupant information, current proof of income for all household members and a valid photo identification.

For your convenience, UGI has enclosed a recertification application. Please mail the completed application and your supporting documents to Community Action Partnership of Lancaster County at 601 S. Queen Street, Lancaster, PA 17602. If you need assistance in completing this application, please call (717)299-7301.

Failure to recertify and verify your current income within 30 days may result in removal from program and loss of CAP benefits which include:

- Personalized monthly CAP amount (based on income or average bill)
- CAP credits (difference between billed usage and CAP amount)
- Forgiveness of past due debt

If you have any questions about your CAP bill, please call UGI at 1-800-276-2722.

We look forward to your continued participation in CAP.

Sincerely,

UGI Customer Outreach Department

Si necesita ayuda para pagar su factura de UGI o desea obtener más información sobre los programas disponibles que pueden ayudarlo con su factura de servicios públicos, comuníquese con UGI al (800) 276-2722. UGI cuenta con intérpretes disponibles, sin costo adicional.

https://www.youtube.com/watch?v=aIwjDpWaOfA

https://www.youtube.com/watch?v=uuBNEa6toxE

OPERATION SHARE ENERGY FUND

Operation Share Energy Fund provides energy assistance grants to qualified households within the UGI local service area. Funding comes from a UGI Corporate donation, as well as individual donations from UGI employees and customers. 100% of every dollar donated goes directly to a local household in need.

Energy to do more®

Give Warmth.

Donate to Operation Share, a 501(c)3 nonprofit that provides grants towards income-qualified customers who have experienced a hardship.

To help your neighbors, visit **www.UGI.com/Opshare** to learn more.

Get Warmth.

If your monthly income (before taxes) is at or below a certain level, you can apply for an Operation Share grant. Grants do not have to be paid back.

To learn more about the income guidelines, please visit **www.UGI.com/Opshare**.

You can also mail your contribution to: Operation Share Energy Fund, P.O. Box 13009, Reading, PA 19612-3009

Make checks payable to "Operation Share Energy Fund" and please circle the area you want your contribution to go to: **Central** | **Electric** | **North** | **South**

00290875

FUNDACION OPERATION SHARE

Operation Share Energy Fund proporciona ayuda de asistencia energetica a los hogares calificados, dentro del area local de UGI. Los fondos de esta fundacion proviene de donaciones corporativas de UGI, asi como de donaciones individuales de empleados y clientes de UGI. El 100% de cada dollar donado va directamente a un hogar local necesitado.

UGI Energy to do more®

Muestre Empatia.

Haga una donación a Operation Share, una organización sin fines de lucro 501(c)3 que brinda ayuda a clientes con ingresos calificados que han experimentado dificultades.

Para ayudar a sus vecinos, visite **www.UGI.com/Opshare** para mas detalles.

Reciba Empatia.

Si su ingreso mensual (antes de impuestos) es O esta por debajo de un cierto nivel, puede solicitar para la ayuda de fondos de Operación.
Las ayudas recibidas no tiene que ser devuelta.

Para obtener más información sobre las pautas de ingresos, por favor visite para mas detalles **www.UGI.com/Opshare**.

También puedes enviar su contribución por correo a: Operation Share Energy Fund, P.O. Box 13009, Reading, PA 19612-3009

Haga los cheques a nombre de "Operation Share Energy Fund" y por favor circule el área a la que desea que vaya su contribución: **Central** | **Electricidad** | **Norte** | **Sur**

00290875

ASSISTANCE PROGRAMS

www.ugi.com/helpinfo

Your Current Situation	Start With This Program
You have no heat, or an active termination notice, and limited income. (Note: Enrollment for this program occurs in early November of each year and ends in April the following year.)	**Low Income Home Energy Assistance Program (LIHEAP)** Grant. It does not have to be paid back, and is run by the state of PA.
You have high debt and would benefit from fixed monthly payments and bill "forgiveness" of utility debt.	**UGI Customer Assistance Program (CAP)** provides a personalized monthly payment amount based on percentage of income or average bill at the property.
You have a temporary hardship (death of wage earner, loss of job, sickness, etc.) that prevents you from paying your utility bills.	**Operation Share Grant** does not have to be paid back.
Your home is cold and drafty in the winter and keeping the thermostat at a low setting does not help.	**UGI Low Income Usage Reduction Program (LIURP).** This program provides energy-saving measures to your home, at no cost to you.

How to get help:

- Ask the agency that provided this information to you for an application for the program you're interested in – you can benefit from multiple programs.
- Contact UGI at (800) UGI WARM and speak with one of our helpful WARM representatives – they can review information and eligibility with you but in most cases you must provide proof of income to your local Community Based Agency in order to enroll.
- Visit www.ugi.com/helpinfo to learn more about customer assistance programs, appliance rebates, and billing options.
- Call 211 to get connected with a resource specialist for free.

UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives can assist you by providing information on a variety of energy assistance programs, making referrals to local agencies, offering participation in fuel funds or establishing payment arrangements. Call (800) UGI-WARM or (800) 844-9276 to learn more.

Energy to do more®

Spanish (ES-US)	UGI está comprometida a ayudar a los clientes que hacen un esfuerzo sincero para pagar sus facturas. Nuestros representantes pueden ayudarlo al proporcionar información sobre diversos programas de asistencia energética, haciendo derivaciones a agencias locales, ofreciendo participación en fondos de combustible o estableciendo acuerdos de pago. Hay intérpretes de servicios de idiomas disponibles para ayudar por teléfono. Llame al (800) UGI-WARM u (800) 844-9276 para obtener más información.
Ukrainian (UK-UA)	Компанія UGI прагне допомагати клієнтам, які докладають щирих зусиль для оплати рахунків. Наші представники можуть допомогти вам, надаючи інформацію про різноманітні програми енергетичної допомоги, надсилаючи рекомендації до місцевих агентств, пропонуючи участь у паливних фондах або приймаючи умови оплати. Для допомоги у спілкуванні телефоном доступні послуги перекладачів. Зателефонуйте (800) UGI-WARM або (800) 844-9276, щоб дізнатися більше.
Russian (RU-RU)	Компания UGI стремится помогать клиентам, которые прилагают искренние усилия для оплаты счетов. Наши представители могут помочь вам, предоставляя информацию о различных программах энергетической помощи, направляя рекомендации в местные агентства, предлагая участие в топливных фондах или принимая условия оплаты. Для помощи в общении по телефону доступны услуги переводчиков. Позвоните по телефону (800) UGI-WARM или (800) 844-9276, чтобы узнать больше.
Italian (IT-IT)	UGI si impegna ad aiutare i clienti che si sforzano sinceramente di pagare le proprie fatture. I nostri rappresentanti possono assistervi fornendo informazioni su una varietà di programmi di assistenza energetica, indirizzandovi alle agenzie locali, offrendo la partecipazione a fondi per il carburante o stabilendo accordi di pagamento. Gli interpreti del servizio linguistico sono disponibili per fornire assistenza telefonica. Chiamare (800) UGI-WARM o (800) 844-9276 per ulteriori informazioni.
Hindi (HI-IN)	UGI उन ग्राहकों की मदद करने के लिए प्रतिबद्ध है, जो अपने बिलों का भुगतान करने के लिए गंभीरता से प्रयास करते हैं। हमारे प्रतिनिधि विभिन्न ऊर्जा सहायता कार्यक्रमों के बारे में जानकारी प्रदान करके, स्थानीय एजेंसियों को रेफ़रल बनाकर, ईंधन कोषों में भागीदारी की पेशकश करके या भुगतान व्यवस्था स्थापित करके आपकी सहायता कर सकते हैं। फोन पर सहायता के लिए भाषा सेवा दुभाषिए उपलब्ध हैं। अधिक जानने के लिए (800) UGI-WARM या (800) 844-9276 पर कॉल करें।
French (FR-FR)	UGI s'engage à aider les clients qui font réellement de leur mieux pour payer leurs factures. Nos représentants peuvent vous aider en vous fournissant des informations sur divers programmes d'aide énergétique, en vous orientant vers des agences locales, en vous invitant à participer à des programmes de financement du carburant ou encore en vous proposant des modalités de paiement alternatives. Un service d'interprétariat par téléphone est mis à votre disposition. Appelez le (800) UGI-WARM ou le (800) 844-9276 pour en savoir plus.
German (DE-DE)	UGI ist bestrebt, Kunden zu helfen, die sich aufrichtig bemühen, ihre Rechnungen zu bezahlen. Unsere Vertreter können Ihnen helfen, indem sie Sie über eine Vielzahl von Energiehilfeprogrammen informieren, Sie an lokale Behörden verweisen, Ihnen die Teilnahme an Brennstofffonds anbieten oder Zahlungsvereinbarungen treffen. Dolmetscher des Sprachdienstes stehen Ihnen telefonisch zur Verfügung. Rufen Sie uns an unter (800) UGI-WARM oder (800) 844-9276, um mehr zu erfahren.
Arabic (AR)	تلتزم شركة UGI بمساعدة العملاء الذين يبذلون قصارى جهدهم لتسديد فواتيرهم. يستطيع ممثلونا مساعدتكم من خلال تقديم معلومات عن مجموعة متنوعة من برامج المساعدة في مجال الطاقة، أو إجراء إحالات إلى الوكالات المحلية، أو إتاحة المشاركة في صناديق الوقود، أو إنشاء ترتيبات للسداد. يتوفر مترجمون فوريون كجزء من الخدمات اللغوية لمساعدتكم عبر الهاتف. يُرجى الاتصال على الرقم (800 UGI-WARM) أو الرقم (800 844-9276) لمعرفة المزيد.
Japanese (JA-JP)	UGIでは、料金のお支払いに努力されているお客様をサポートするために、様々な取り組みをしております。弊社社員が、種々のエネルギー支援プログラムに関する情報の提供、最寄りの代理店への紹介、燃料基金への参加の案内、支払手続きの手配などを通じてお客様をサポートします。お電話では通訳サービスをご利用いただけます。詳しくは(800) UGI-WARM または(800) 844-9276 までお電話ください。
Simplified Chinese (ZH-CN)	UGI 致力于帮助真诚尽力支付账单的客户。我们的代表可以通过提供有关各种能源援助计划的信息、推荐给当地机构、参与燃料基金或建立付款安排来为您提供帮助。可通过电话获得语言服务口译服务。请致电 (800) UGI-WARM 或 (800) 844-9276 了解更多信息。

Energy to do more®

Need Help Paying Your UGI Bill? Join UGI WARM Representatives for one of our Energy Assistance Events

When: **Tomorrow - February 11, 2025**

Hours: **10 AM to 2:30 PM**

We will stop accepting applications 15 minutes prior to the close of the event.

Where: **Harrisburg Salvation Army**

506 S 29th St, Harrisburg, PA 17104

Please bring with you:

- ☑ Proof of Identification
- ☑ Proof of Income and Income Sources for All Members of Your Household
- ☑ UGI Bill or UGI Account Number*
- ☑ List of Monthly Expenses (utility bills, rent/mortgage, etc.)

Our representatives will be available to provide information to you about programs available to help you manage your UGI bills.

If you currently have a shut off notice, or are shut off, please call 800-276-2722 prior to attending an event. You will receive information about what is needed to restore service and to bring that information with you to the event.

These events are free for UGI customers.

**If you are currently purchasing your natural gas from a Supplier, enrollment into the UGI Customer Assistance Program is currently not available. You may contact us to discuss your options for future enrollment at 800-276-2722.*

Can't make these events or looking for a closer one?

VIEW FULL LIST OF EVENTS

IMPORTANT NOTE FOR UGI CUSTOMER ASSISTANCE PROGRAM (CAP) CUSTOMERS:

If you are enrolled in CAP and need to recertify, bring the documents above to this event and we will help you with the recertification process.

BILL PAY OPTIONS | ASSISTANCE PROGRAMS

Energy to do more®

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Hours: 10 AM to 2:30 PM

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VIEW FULL LIST OF EVENTS

IMPORTANT NOTE FOR UGI CUSTOMER ASSISTANCE PROGRAM (CAP) CUSTOMERS:

If you are enrolled in CAP and need to recertify, bring the documents above to this event and we will help you with the recertification process.

BILL PAY OPTIONS | ASSISTANCE PROGRAMS

UGI Utilities, Inc.
February 10 at 10:01 AM ·

Our Free Energy Assistance Event for UGI Customers in Harrisburg, PA, is February 11 from 10 a.m.-2:30 p.m. UGI representatives will be at the Harrisburg Salvation Army, 506 South 29th Street, Harrisburg, PA. For more information, including what to bring to the event and dates and locations of future in-person events, visit https://www.ugi.com/energy-assistance-event/.

Energy to do more*
CONTACT US
Get Help With Your Energy Bills
Struggling to pay your utility bills? The UGI Utilities Customer Assistance Program (CAP) can help you. Complete the short form below to check your eligibility; if you are eligible, UGI will provide you with more information on how to enroll.
First Name*
Jane
Last Name*
Doe
Email*
jane.doe@example.com
Zip Code*
17111
Does the Household receive monthly income for minors?*
Yes
No
Number of Household Members*
Select
Monthly Income for All Adults in Household*
1000
CHECK MY ELIGIBILITY

Manage Energy Bills Better with Assistance through UGI

There are many reasons that you or someone you know may need help with their energy bills. The UGI Utilities Customer Assistance Program (CAP) is here to help. CAP is tailored to provide financial assistance through personalized monthly payments based on your income or average bill.

Program Benefits include:

- A personalized monthly payment based on income or average bill.
- Past due debt forgiveness with on-time monthly payments.
- The potential for additional forgiveness while in the program, including the difference between your CAP payment and the actual usage bill.

CAP can empower you to not only lower your monthly energy bills but also create a more stable financial future.

We invite you to check your eligibility for CAP and discover how you can benefit from reduced payments and debt forgiveness. It's all part of our commitment to support our community and provide assistance to those who need it most.

UGI Gas Exhibit BJM-6R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

CAUSE-PA RESPONSE TO UGI INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION – SET I

REQUEST:

3) Reference CAUSE-PA Statement No. 1, page 20, lines 6-7:

   a. Is it Mr. Cicero's belief that the Commission should change the utilization of the Federal Poverty Income Guidelines ("FPIG") to the Self-Sufficiency Standard for Universal Service Program enrollment criteria? If so, please explain why.

   b. Does Mr. Cicero agree that the FPIG is a widely utilized and effective benchmark for measuring income status in the utility industry? If not, please explain why.

RESPONSE:

a. The term "belief" is not defined and unclear. Mr. Cicero has not taken the position in this case that the Commission should change its universal service program financial eligibility criteria. As stated by Mr. Cicero in this testimony, "[t]he Self Sufficiency Standard helps illuminate the full scope of utility insecurity and the need for utility rates and rate design to not exacerbate the precarious financial position of those UGI customers who, while not considered low income by the Commission nevertheless struggle to make ends meet each month." CAUSE-PA Statement No 1 at 21:5-8.

b. Mr. Cicero agrees that the federal poverty level is a widely used benchmark for measuring income status in the utility industry. Mr. Cicero does not agree that it is an effective benchmark for measuring need because it does not account for differences in geography or family composition (i.e., ages of children).

Response Prepared by or under the supervision of Patrick M. Cicero.
Dated: April 27, 2026

UGI Gas Exhibit BJM-7R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 6 (1-17)
Delivered on April 2, 2026

CAUSE-PA-6-17

Request:

Reference UGI St. 12 at 16:17-21.

A. Please describe in detail the methodology used by Experian that resulted in an estimated low income count of 98,785.

B. Does UGI have demographic income data for every one of its residential customers?

C. If the answer to subpart b. above is anything other than an unequivocal yes, please describe why UGI believes that the Experian data accurately counts the number of estimated low income customers within its service territory.

Response:

A. Please see HIGHLY CONFIDENTIAL Attachment CAUSE-PA-1-11 for Experian's January 2026 data assessment and methodology which includes estimated low income counts of 96,137. The methodology used to derive this number is consistent with the methodology used to derive the 2023 figure of 98,785 reported in the Direct Testimony of Brian J. Meilinger, UGI Gas Statement No. 12, at 16:17-21.

B. No.

C. Experian accurately counts the number of estimated low-income customers because their process utilizes insights on actual UGI Gas customers. For the January 2026 data assessment, there was a 90% match rate on name and address. This is in comparison to the methodology of calculating estimated low-income customers reported annually to the Bureau of Consumer Services which is derived by using the United States Census Bureau's American Community Survey 5-year poverty level estimates by county, multiplied by the number of UGI Gas customers in that county.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 6 (1-17)
Delivered on April 2, 2026

CAUSE-PA-6-17 (Continued)

Prepared by or under the supervision of: Brian J. Meilinger

UGI Gas Exhibit BJM-8R

UGI Gas

2018	2026	CAGR
18,068	25,346	4.95%

Year	Avg CAP Enrollment
2018	18,068
2019	19,742
2020	23,855
2021	23,730
2022	20,134
2023	22,844
2024	24,491
2025	25,346

UGI Gas Exhibit BJM-9R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

CAUSE-PA RESPONSE TO UGI INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION – SET I

REQUEST:

8) Reference CAUSE-PA Statement No. 1, page 73, lines 1-10. Mr. Cicero proposes that the Company routinely screen customers for household income level on any non-emergency calls.

   a. Has Mr. Cicero performed any analysis on a customer's willingness to provide income information on calls when income information is not required to address the UGI Gas customer's inquiry? If so, please provide a copy of such analysis.

   b. Has Mr. Cicero performed any analysis to assess the potential impact to UGI Gas's customer satisfaction that might result from asking customers for income information on any non-emergency calls, even if the topic is not related to billing or credit? If so, please provide a copy of such analysis.

   c. Has Mr. Cicero performed any analysis related to the potential impact to the Company's call center department's average handle time to "routinely screen existing customers for household income level on any non-emergency calls – and inquire whether there have been any updates to household income in-formation already noted on accounts"? If so, please provide a copy of such analysis.

   d. Has Mr. Cicero performed any analysis related to cost impacts that may arise due to increased call center average handle time to perform income screening? If so, please provide a copy of such analysis.

   e. Has Mr. Cicero performed any analysis related to the IT costs to enhance the UGI online account portal to perform routine income screening? If so, please provide a copy of such analysis.

   f. Is it Mr. Cicero's belief that UGI Gas customers are willing to provide their utility company with income information for calls that do not require income verification?

RESPONSE:

a.-e. No.

f. The term "belief" is not defined and unclear. By way of further answer, it is Mr. Cicero's position, based on his experience, that when a customer is informed that they may be eligible for a lower rate customers are often willing to provide their demographic information, including their income, in order to determine whether they qualify for a lower rate.

Response Prepared by or under the supervision of Patrick M. Cicero.
Dated: April 27, 2026

UGI Gas Exhibit BJM-10R

Income Ask Survey

Energy to do more®

Summary

Objective: Quantify customer attitudes on concept of asking household income on incoming telephone calls to improve participation in income-based assistance programs

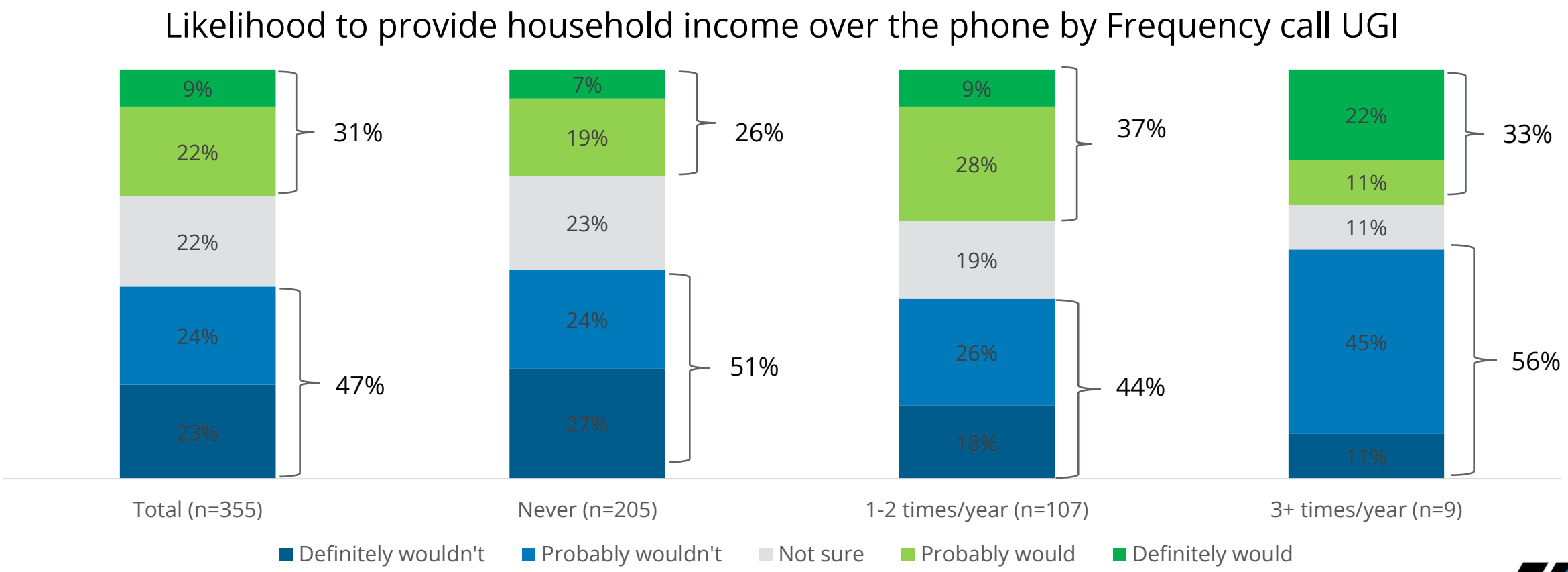
Target Audience: Randomly selected active residential natural gas customers with email address in PA service territory (excluding employees)

Data Collection: Electronic survey; 4,736 survey invites sent; 355 completes for margin-of-error ± 5%

Key Findings:

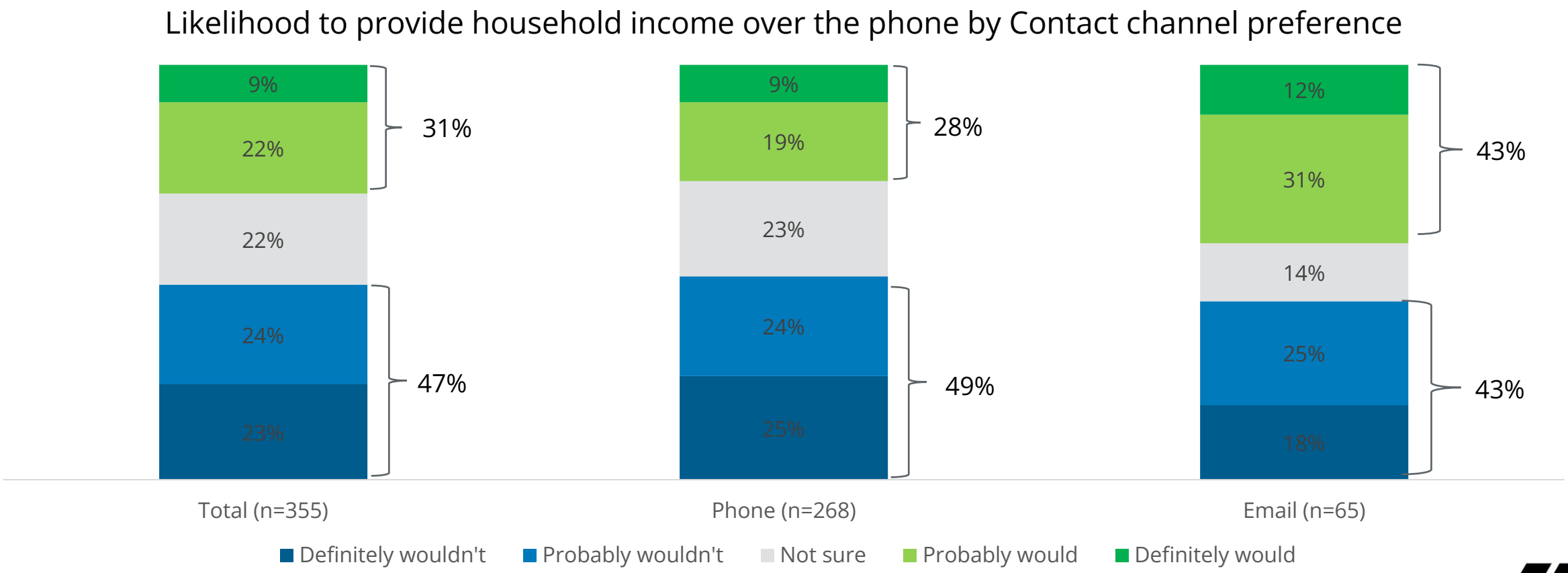
- Roughly half of all respondents stated they would not provide their household income to UGI and one-third stated they would (22% not sure)
  - Only 26% of respondents said they would have no concerns providing their income to UGI
  - Other respondents cited concerns that income data is confidential or they already know they wouldn't qualify for income-based assistance programs
- Still, 60% of respondents expressed some level of interest in learning more about income-based assistance program

Likelihood to Provide Income Data



Energy to do more®

Likelihood to Provide Income Data



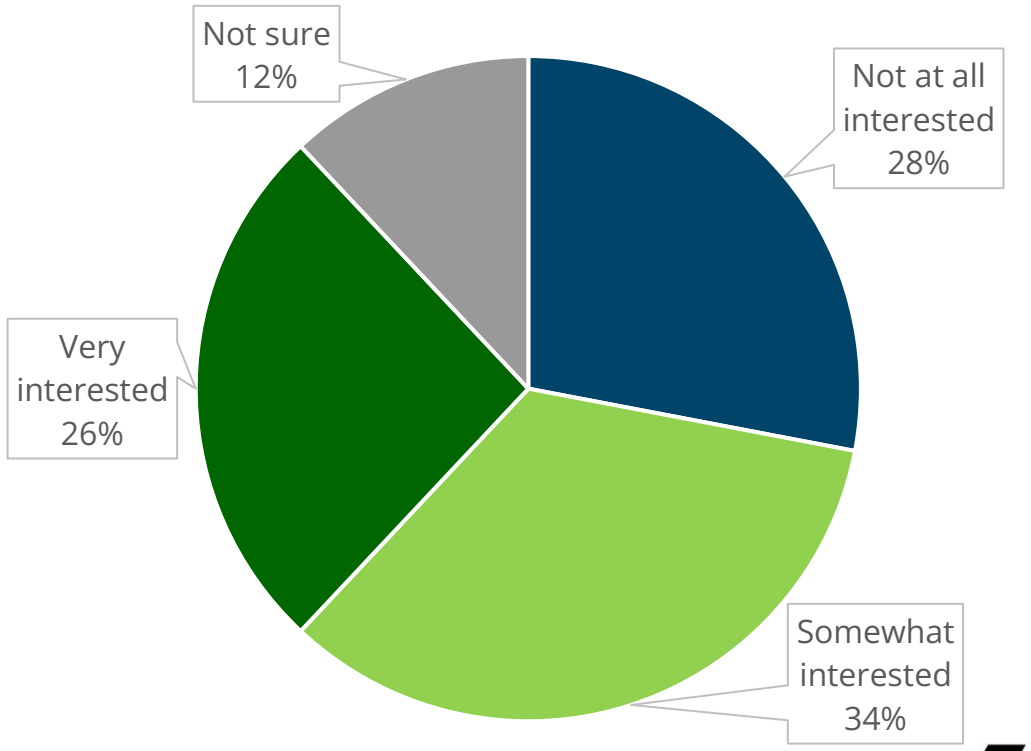
Energy to do more®

Concerns and Interest in Programs

Concerns about Sharing Income

- 37% • That information is confidential
- 31% • Already know I wouldn't qualify for programs
- 16% • Don't need income-based assistance programs
- 8% • Spending extra time on phone unrelated to reason for call
- 3% • Fraud/privacy/misuse of info
- 26% • I would not have any concerns sharing my household income

Interest in Learning about Income-based Assistance Programs



Energy to do more®

UGI Gas Exhibit BJM-11R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET I

17) Reference OCA Statement 6, page 51, lines 16-18, where Mr. Colton testifies, "the Company does a poor job of enrolling its Confirmed Low Income Customers into CAP. UGI Gas data documents that consistently more than 40,000 Confirmed Low Income Customers are not enrolled in CAP."

a) Of the 40,000 customers, is Mr. Colton aware of how many of these customers actually qualify for enrollment in CAP? If so, please provide that number.

b) Of the 40,000 customers, is Mr. Colton aware of how many of these customers have been provided marketing materials to apply for enrollment in CAP? If so, please provide that number.

c) Of the 40,000 customers, is Mr. Colton aware of how many of these customers have been provided materials to apply for enrollment in CAP and have returned a completed CAP application? If so, please provide that number.

d) Of the 40,000 customers, is Mr. Colton aware of how many of these customers that have been provided materials to apply for enrollment in CAP, have returned a completed CAP application, and have been affirmatively denied for CAP because they did not qualify for participation in the program? If so, please provide that number.

Response:

a) No.
b) No.
c) No.
d) No.

Sponsored by: Roger D. Colton

Dated: April 27, 2026.

UGI Gas Exhibit BJM-12R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET III

1. Reference Witness Colton's response to UGI to OCA, Set I-20, stating that SNAP's income limits are consistent with the Federal Poverty Income Guidelines ("FPIG").

   a. Does SNAP eligibility extend to 200% of the Federal Poverty Level ("FPL")? If no, what is the maximum FPL percentage for eligibility?

   b. Are these guidelines consistent with the 150% of the FPL for enrollment in the Customer Assistance Program?

Response:

a. Not necessarily. Households are not eligible for SNAP if they have gross countable income at *or below* the following as of October 2025:

	Max Monthly SNAP Income	Months in Year	Max Annual SNAP Income	100% FPL	Max Annual SNAP as FPL pct
1	$2,610	12	$31,320	$15,960	196%
2	$3,526	12	$42,312	$21,640	196%
3	$4,442	12	$53,304	$27,320	195%
4	$5,360	12	$64,320	$33,000	195%
5	$6,276	12	$75,312	$38,680	195%
6	$7,192	12	$86,304	$44,360	195%
7	$8,110	12	$97,320	$50,040	194%
8	$9,026	12	$108,312	$55,720	194%

https://www.pa.gov/agencies/dhs/resources/snap/snap-income-limits

Contrary to what is asserted in the question, however, having gross countable income below the maximum dollar amounts does not necessarily make a household income eligible for SNAP. SNAP income eligibility, of course, is not based exclusively on gross income as a percent of Poverty Level as asserted in the question. In addition, a household's net income must be less than 100% of Poverty Level. Households must meet both gross and net income limits to income-qualify for SNAP. The closer gross countable income comes to 200% of the Federal Poverty Level, the less likely it is that net income will fall below the additional income-qualifying guideline.

b. Yes. The *maximum* income limits presented above, however, do not demonstrate whether or not demonstrating Food Stamp income participation is "consistent with" the income

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET III

eligibility requirements for CAP. The Table below shows the distribution of Pennsylvania SNAP recipients by Federal Poverty Level in Pennsylvania for the three most recent years available (USDA, Characteristics of Supplemental Nutrition Assistance Program Households):

Distribution of SNAP participating households by gross countable income as percent of poverty status: Pennsylvania				
	Zero gross income	1% to 50% FPL	51% to 100% FPL	101% or more FPL
2020	16.1%	10.2%	48.6%	25.0%
2021***	Not Published			
2022	17.4%	11.3%	39.9%	31.4%
2023###	16.9%	9.4%	37.7%	36.0%

***Due to a lack of data collection caused by the COVID health pandemic, no 2021 data was published.
###Most recent year available (published April 2025).

While USDA does not disaggregate SNAP recipient households into Poverty ranges of 100% to 150% and 150% or more, the disaggregation nonetheless documents that any reasonable distribution of SNAP recipients with income 100% or more would demonstrate the consistency of Food Stamp eligibility with CAP eligibility.

Even the distribution presented above does not fully document the extent to which Food Stamp income eligibility is consistent with CAP income eligibility. The Table below shows the *average* Poverty Level of Food Stamp recipients in Pennsylvania by year for the years 2020 through 2023 (USDA, Characteristics of Supplemental Nutrition Assistance Program Households).

Gross Countable Income as Average Percent of Poverty Level of SNAP Recipient Households: Pennsylvania	
2020	74.8%
2021	***
2022	78.4%
2023###	85.9%

***Due to a lack of data collection caused by the COVID health pandemic, no 2021 data was published.
###Most recent year available (published April 2025).

Sponsoring Witness: Roger Colton
Date: May 11, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division
:

VERIFICATION

I, Roger Colton, hereby state that the facts above set forth in my Answers to UGI-Gas Interrogatories to OCA, Set 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 11, 2026

Signature: /s/ *Roger Colton*
Roger Colton

Address: Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

UGI Gas Exhibit BJM-13R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET I

16) Reference OCA Statement 6, page 4, lines 14-20. Please provide sample content that Mr. Colton is recommending as part of his plain language notice informing customers of their right to enroll in the Customer Assistance Program ("CAP").

Response:

Mr. Colton did not recommend specific language informing customers of their right to enroll in the Customer Assistance Program (along with arrearage forgiveness) as an alternative to entering into a payment arrangement through which customers would pay a non-discounted bill for current service plus a monthly installment toward their pre-existing arrears. No "sample content" has been prepared.

Sponsored by: Roger D. Colton

Dated: April 27, 2026.

UGI Gas Exhibit BJM-14R
(No Public Version Available)

UGI Gas Exhibit BJM-15R

UGI UTILITIES, GAS DIVISON
SAMPLE OF DUNNING NOTICE
FEBRUARY 2026

Attachment OCA-6-8.1
D. V. Adamo
Page 1 of 2

UGI Utilities, Inc.
PO Box 13009
Reading, PA 19612-3009
(800) 276-2722

Energy to do more®

February 03, 2026

[redacted]

Regarding: [redacted]
Service Address: [redacted]

Hello,

Our records indicate that you have a past due balance of $115.41 on the UGI account listed above. Please arrange for payment of this amount as soon as possible. If this amount has already been paid, you may disregard this notice.

If you need help with your utility bill, you may be eligible for the UGI Customer Assistance Program (CAP). CAP offers a personalized monthly payment and provides bill and debt forgiveness with on-time payments. To apply for CAP, you will need to provide proof of household income and identification. To see if you are eligible, and to complete an application, visit ugi.com/CAP or call us at 800-UGI-WARM.

If you have any other questions regarding this bill or to make payment, please visit UGI online at ugi.com or call us at 800-276-2722, Monday through Friday 8 am to 5 pm.

Thank You,

UGI Utilities

Energy to do more®

If you pay at a payment agent, please take your entire bill. Make check payable to UGI.
Keep this part for your records. **Important information is on the back of this bill.**

UGI Utilities, Inc.
PO Box 15503
Wilmington, DE 19850-5503

Account Number [redacted]

Please pay by the due date to avoid the late charge. Please return this portion with your payment.

Amount Due
115.41

[redacted]

[redacted]

UGI UTILITIES, GAS DIVISON
SAMPLE OF DUNNING NOTICE
FEBRUARY 2026

Attachment OCA-6-8.1
D. V. Adamo
Page 2 of 2

Z110

UGI Gas Exhibit BJM-16R

UGI UTILITIES - GAS DIVISION
SAMPLE TEN DAY SHUT OFF NOTICE
FEBRUARY 2026

Attachment OCA-6-8.2
D. V. Adamo
Page 1 of 2

10 DAY SHUT-OFF NOTICE
ADVISO DE SUSPENSION DE SERVICO

February 16, 2026

Your GAS Service May Be Shut Off!
Because your bill is past due, we will shut off the service to [redacted] on or after 8:00 a.m. on **03-02-2026**. **We may act on this notice for up to 60 days.** Your service may be protected from termination through 03-31-26. Refer to the "Winter Notice Provisions" section on the back of this notice.

We will NOT shut off your service if you do ONE of the following:
- Call us at (800) 276-2722 to arrange to pay your past due bill of **$1,033.00**.
- Show us a paid receipt for the past due amount.
- Call **(800) 276-2722 right away** if you dispute this bill.

If we shut off your service, you may have to pay all of the following before we can turn your service on:

Amount Due	$	1,033.00
Security Deposit	$	222.00
Turn-on Charge	$	73.00
Total	**$**	**1,328.00**

MEDICAL EMERGENCY NOTICE
Let us know if someone living in your home is seriously ill or has a medical condition. **WE WILL NOT SHUT OFF YOUR SERVICE provided you:**
1. Have your licensed physician or nurse practitioner certify in writing that such an illness exists and that it may be aggravated if your service is shut off; **AND**
2. Make some equitable arrangements to pay the company your current bills for service.

IMPORTANT TO KNOW
Before we shut off your utility service please read the back of this notice. You may be eligible for certain protections from shut off.
¡Atención! Esto es un mensaje muy importante. Si usted no lo entiende, por favor llame at (800) 276-2722.

To make a payment by phone or to discuss your bill, please call (800) 276-2722. Thank You

If you pay in person please bring your entire bill. Make check payable to UGI.
Keep this part for your records. **Important information is on the back of this bill.**

Energy to do more®

UGI Utilities, Inc.
PO Box 15503
Wilmington, DE 19850-5503

Account Number [redacted]

Amount Due
1,033.00

[redacted]

[redacted]

UGI UTILITIES - GAS DIVISION
SAMPLE TEN DAY SHUT OFF NOTICE
FEBRUARY 2026

Attachment OCA-6-8.2
D. V. Adamo
Page 2 of 2

Z111

IMPORTANT TO KNOW - BEFORE WE SHUT OFF YOUR UTILITY SERVICE

- If you have questions or need more information, please call us today at (800) 276-2722. After you talk with us, if you are not satisfied, you may file a complaint with the Public Utility Commission (PUC). The PUC may delay the shut off if you file the complaint before the shut-off date. To contact them call 1-800-692-7380 or write to: Pennsylvania Public Utility Commission, Box 3265, Harrisburg, PA 17105-3265.
- **If we shut off your service during the winter months (between Dec.1 - Mar. 31)** we will restore your service within 24 hours of your meeting all requirements/conditions to have service reconnected. Where street digging is required it may take up to 7 days.
- If you currently have a valid protection from Abuse order from a court your service cannot be terminated during the winter without PUC permission. There are some additional protections available to you. **Call us immediately at (800) 276-2722**. (You will be required to provide us with a copy of the order.)
- You may be eligible for a payment agreement or special assistance programs such as the UGI Customer Assistance Program (CAP). CAP offers a personalized monthly payment and provides bill and debt forgiveness with on-time payments. To apply for CAP, you will need to provide proof of household income and identification. To see if you are eligible, visit ugi.com/CAP or call us at (800) 276-2722.
- You may be eligible to pay the full past due amount on the most recent payment agreement.
- If your landlord pays your utility bill: You have certain legal protections. Call us at (800) 276-2722.
- If you have trouble understanding or speaking English or have a disability call us at (800) 276-2722 for free interpretation.
- If your service is shut off, you may be required to pay more than the amount listed on the front of this notice to have your service turned back on. You may have to pay any additional bills that have become past due.
- All adult occupants of the premise whose names are on the mortgage, deed, or lease are considered the "customer" and are responsible for payment of this bill.
- If service is shut off, ANY adult occupant who has been living at the premise may have to pay all or portions of this bill to have service restored.
- If your service is shut off, you must contact us after your payment has been made to be sure you have met all conditions to have the service turned back on and to arrange access to your premises.
- After all conditions have been met to have the service turned back on, it may take up to seven days to have your service restored. Please contact us to discuss the details.

WINTER NOTICE PROVISIONS (between December 1 - March 31)

- **Contact us BEFORE the shut off date** to give us household income & occupant information to see if you qualify for any assistance programs.
- **If your income is at or below 250% of the federal poverty guidelines, we must first ask the PUC for permission to shut off your service.** Add together the monthly income of the adults in your household. If that number is the same or less than the amount listed in the chart below for your household size, call us immediately at (800) 276-2722. You may need to provide us with proof of your income.

Monthly Income at 250% of Federal Poverty Level:2026					
Household Size	1	2	3	4	Add $1,183 for each additional household member.
Monthly Income	$ 3,325	$ 4,508	$ 5,692	$ 6,875	

¡Atención! Esto es un mensaje muy importante. Si usted no lo entiende, por favor llame at (800) 276-2722.

UGI Gas Exhibit BJM-17R

UGI UTILITIES - GAS DIVISION
SAMPLE SHUT OFF NOTICE DOORHANGER
FEBRUARY 2026

Attachment OCA-6-8.3
D. V. Adamo
Page 1 of 2

Energy to do more

To ALL Adult OCCUPANTS

Date _____ Meter #_____

SHUT-OFF NOTICE

AVISO DE SUSPENCION DE SERVICIO

Order # _____

Customer # _____

Name _____

YOUR GAS/ELECTRIC SERVICE MAY BE SHUT OFF!

Because your bill is past due, we will shut off the service to

_____

on or after 8:00 a.m. on _____

We may act on this notice for up to 60 days.

The Service is being shut off because:

_____ You did not pay your past due bill.
_____ You did not pay your security deposit.
_____ You have not given UGI access to our meter.
_____ You need to complete an application/establish credit.
_____ Rejected payment.
_____ Safety Check.

We will NOT shut off your service if you do ONE of the following:

- Call us at **1-800-276-2722** to:
  - Show us a paid receipt for the past due amount
  - Arrange to pay your past due bill.
  - Pay the amount you owe on your payment plan.
  - Give UGI access to read our meter.
  - Complete the credit/application process.
- Call **1-800-276-2722 right away** if you dispute this bill or to provide us with household income and occupant information. You may be eligible for a payment agreement or special assistance programs.

If we shut off your service, you may have to pay all of the following before we can turn your service on:

Overdue Amount	$ _____
Security Deposit	$ _____
Turn-on Charge	$ _____
Total	**$ _____**

- **Please call our office at 1-800-276-2722.**

MEDICAL EMERGENCY NOTICE

Let us know if someone living in your home is seriously ill or has a medical condition. **WE WILL NOT SHUT OFF YOUR SERVICE provided you:**

1.Have your licensed physician or nurse practitioner certify in writing that such an illness exists and that it may be aggravated if your service is shut off; **AND**

2.Make some equitable arrangement to pay the company your current bills for service.

IMPORTANT TO KNOW

Before we shut off your utility service please read the back of this notice. You may be eligible for certain protections from shut off.

Atencion!

Este es en mensaje muy importante. Si usted no lo entiende, favor de llama a 1-800-276-2722.

UGI UTILITIES - GAS DIVISION
SAMPLE SHUT OFF NOTICE DOORHANGER
FEBRUARY 2026

Attachment OCA-6-8.3
D. V. Adamo
Page 2 of 2

Energy to do more

IMPORTANT TO KNOW – BEFORE WE SHUT OFF YOUR UTILITY SERVICE

- If you have questions or need more information, please call us today at 1-800-276-2722. After you talk with us, if you are not satisfied, you may file a complaint with the Public Utility Commission (PUC). The PUC may delay the shut off if you file the complaint before the shut-off date. To contact them call 1-800-692-7380 or write to: Pennsylvania Public Utility Commission, Box 3265, Harrisburg, PA 17105-3265.
- **If we shut off your service during the winter months (between Dec.1 – Mar. 31)** we will restore your service within 24 hours of your meeting all requirements/conditions to have service reconnected. Where street digging is required it may take up to 7 days.
- If you currently have a valid Protection From Abuse order from a court your service cannot be terminated during the winter without PUC permission. There are some additional protections available to you. **Call us immediately at 1-800-276-2722.** (You will be required to provide us with a copy of the order.)
- You may be eligible for a payment agreement or special assistance programs such as the UGI Customer Assistance Program (CAP). CAP offers a personalized monthly payment and provides bill and debt forgiveness with on-time payments. To apply for CAP, you will need to provide proof of household income and identification. To see if you are eligible, **visit ugi.com/CAP or call us at 1-800- 276-2722.**
- You may be eligible to pay the full past due amount on the most recent payment agreement.
- If your landlord pays your utility bill: You have certain legal protections. Call us at 1-800-276-2722.
- If you have trouble understanding or speaking English or have a disability call us at 1-800-276-2722 for free interpretation.
- If your service is shut off, you may be required to pay more than the amount listed on the front of this notice to have your service turned back on. You may have to pay any additional bills that have become past due.
- All adult occupants of the premise whose names are on the mortgage, deed, or lease are considered the "customer" and are responsible for payment of this bill.
- If service is shut off, ANY adult occupant who has been living at the premise may have to pay all or portions of this bill to have service restored.
- If your service is shut off, you must contact us after your payment has been made to be sure you have met all conditions to have the service turned back on and to arrange access to your premises.
- After all conditions have been met to have the service turned back on, it may take up to seven days to have your service restored. Please contact us to discuss the details.

WINTER NOTICE PROVISIONS (between December 1 – March 31)

- **Contact us BEFORE the shut off date** to give us household income & occupant information to see if you qualify for any assistance programs.
- **If your income is at or below 250% of the federal poverty guidelines, we must first ask the PUC for permission to shut off your service.** Add together the monthly income of the adults in your household. If that number is the same or less than the amount listed in the chart below for your household size, call us immediately at 1-800-276-2722. You may need to provide us with proof of your income.

Monthly Income at 250% of Federal Poverty Level: 2025					
Household Size	1	2	3	4	Add $1,146 for each additional household member.
Monthly Income	$3,260	$4,406	$5,552	$6,698	

Atención! Este es en mensaje muy importante. Si usted no lo entiende, favor de llamar al 1-800-276-2722.

0-01-094 Rev 2/25

UGI Gas Exhibit BJM-18R

UGI UTILITIES - GAS DIVISION Attachment OCA-6-8.4
SAMPLE 48-HOUR SHUT OFF NOTICE DOORHANGER D. V. Adamo
FEBRUARY 2026 Page 1 of 2

Energy to do more

To ALL Adult OCCUPANTS

Date _____ Meter #_____

48-HOUR SHUT-OFF NOTICE

AVISO DE SUSPENCION DE SERVICIO

Order # _____

Customer # _____

Name_____

YOUR GAS/ELECTRIC SERVICE MAY BE SHUT OFF!

Because your bill is past due, we will shut off the service to

_____

on or after 8:00 a.m. on
without further notice.

The Service is being shut off because:

_____ You did not pay your past due bill.
_____ You did not pay your security deposit.
_____ You have not given UGI access to our meter.
_____ You need to complete an application/establish credit.
_____ Rejected payment.
_____ Safety Check.

We will NOT shut off your service if you do ONE of the following:

- Call us at **1-800-276-2722** to:
  - Show us a paid receipt for the past due amount.
  - Arrange to pay your past due bill.
  - Pay the amount you owe on your payment plan.
  - Give UGI access to read our meter.
  - Complete the credit/application process.
- Call **1-800-276-2722 right away** if you dispute this bill or to provide us with household income and occupant information. You may be eligible for a payment agreement or special assistance programs.

If we shut off your service, you may have to pay all of the following before we can turn your service on:

Overdue Amount	$ _____
Security Deposit	$ _____
Turn-on Charge	$ _____
Total	**$**_____

- **Please call our office at 1-800-276-2722.**

MEDICAL EMERGENCY NOTICE

Let us know if someone living in your home is seriously ill or has a medical condition. **WE WILL NOT SHUT OFF YOUR SERVICE provided you:**

1. Have your licensed physician or nurse practitioner certify in writing that such an illness exists and that it may be aggravated if your service is shut off; **AND**
2. Make some equitable arrangement to pay the company your current bills for service.

IMPORTANT TO KNOW

Before we shut off your utility service please read the back of this notice. You may be eligible for certain protections from shut off.

Atencion!

Este es en mensaje muy importante. Si usted no lo entiende, favor de llama a 1-800-276-2722.

UGI UTILITIES - GAS DIVISION
SAMPLE 48-HOUR SHUT OFF NOTICE DOORHANGER
FEBRUARY 2026

Attachment OCA-6-8.4
D. V. Adamo
Page 2 of 2

IMPORTANT TO KNOW – BEFORE WE SHUT OFF YOUR UTILITY SERVICE

- If you have questions or need more information, please call us today at 1-800-276-2722. After you talk with us, if you are not satisfied, you may file a complaint with the Public Utility Commission (PUC). The PUC may delay the shut off if you file the complaint before the shut-off date. To contact them call 1-800-692-7380 or write to: Pennsylvania Public Utility Commission, Box 3265, Harrisburg, PA 17105-3265.
- **If we shut off your service during the winter months (between Dec.1 – Mar. 31)** we will restore your service within 24 hours of your meeting all requirements/conditions to have service reconnected. Where street digging is required it may take up to 7 days.
- If you currently have a valid Protection From Abuse order from a court your service cannot be terminated during the winter without PUC permission. There are some additional protections available to you. **Call us immediately at 1-800-276-2722.** (You will be required to provide us with a copy of the order.)
- You may be eligible for a payment agreement or special assistance programs such as the UGI Customer Assistance Program (CAP). CAP offers a personalized monthly payment and provides bill and debt forgiveness with on-time payments. To apply for CAP, you will need to provide proof of household income and identification. To see if you are eligible, visit **ugi.com/CAP or call us at 1-800- 276-2722.**
- You may be eligible to pay the full past due amount on the most recent payment agreement.
- If your landlord pays your utility bill: You have certain legal protections. Call us at 1-800-276-2722.
- If you have trouble understanding or speaking English or have a disability call us at 1-800-276-2722 for free interpretation.
- If your service is shut off, you may be required to pay more than the amount listed on the front of this notice to have your service turned back on. You may have to pay any additional bills that have become past due.
- All adult occupants of the premise whose names are on the mortgage, deed, or lease are considered the "customer" and are responsible for payment of this bill.
- If service is shut off, ANY adult occupant who has been living at the premise may have to pay all or portions of this bill to have service restored.
- If your service is shut off, you must contact us after your payment has been made to be sure you have met all conditions to have the service turned back on and to arrange access to your premises.
- After all conditions have been met to have the service turned back on, it may take up to seven days to have your service restored. Please contact us to discuss the details.

WINTER NOTICE PROVISIONS (between December 1 – March 31)

- **Contact us BEFORE the shut off date** to give us household income & occupant information to see if you qualify for any assistance programs.
- **If your income is at or below 250% of the federal poverty guidelines, we must first ask the PUC for permission to shut off your service.** Add together the monthly income of the adults in your household. If that number is the same or less than the amount listed in the chart below for your household size, call us immediately at 1-800-276-2722. You may need to provide us with proof of your

Monthly Income at 250% of Federal Poverty Level: 2025					
Household Size	1	2	3	4	Add $1,146 for each additional household member.
Monthly Income	$3,260	$4,406	$5,552	$6,698	

Atención! Este es en mensaje muy importante. Si usted no lo entiende, favor de llamar al 1-800-276-2722.

0-01-095 Rev. 2/25

UGI Gas Exhibit BJM-19R

UGI UTILITIES - GAS DIVISION
SAMPLE SHUT OFF DOORHANGER
FEBRUARY 2026

Attachment OCA-6-8.5
D. V. Adamo
Page 1 of 2

Energy to do more

To ALL Adult OCCUPANTS

Date _____ Meter #_____

YOUR GAS/ELECTRICITY HAS BEEN SHUT OFF

AVISO DE SUSPENCION DE SERVICIO

Order #_____

Customer # _____

Name _____

Service Address

_____

We shut off your service because:

_____ You did not pay your past due bill.
_____ You did not pay your security deposit.
_____You have not given UGI access to our meter.
You did not meet the requirements and/or complete the application for service process.
_____ Theft of Service or Tampering with utility equipment.
_____ Rejected payment.
_____Safety Check.

TO HAVE YOUR SERVICE TURNED BACK ON YOU MUST DO ALL OF THE FOLLOWING.

- **Please call our office at 1-800-276-2722 to arrange to pay your:**

Past Due Bill	$ _____
Security Deposit	$ _____
Turn-on Charge	$ _____
Total	**$** _____

- **Give us access to our meter.**
- **Resolve the items noted above.**
- **You must contact us after your payment has been made to be sure you've met all conditions to have the service turned back on and arrange access to your premises.**
- **If someone in your home is seriously ill, read the MEDICAL EMERGENCY NOTICE on the back of this notice.**

MEDICAL EMERGENCY NOTICE

Let us know if someone living in your home is seriously ill or has a medical condition. **WE WILL RESTORE YOUR SERVICE provided you:**

1. Have your licensed physician or nurse practitioner certify in writing that such an illness exists and that it may be aggravated if your service is not restored; AND
2. Make some equitable arrangement to pay the company your current bills for service.

IMPORTANT

PLEASE READ THE BACK OF THIS NOTICE.

Atencion!

Este es en mensaje muy importante. Si usted no lo entiende, favor de llama a 1-800-276-2722.

UGI UTILITIES - GAS DIVISION
SAMPLE SHUT OFF DOORHANGER
FEBRUARY 2026

Attachment OCA-6-8.5
D. V. Adamo
Page 2 of 2

If you have questions or need more information, please call us today at 1-800-276-2722. After you talk with us, if you are not satisfied, you may file a complaint with the Public Utility Commission (PUC). The PUC will attempt to help you with your problem. To contact them call (800) 692-7380 or write to: Pennsylvania Public Utility Commission, Box 3265, Harrisburg, PA 17105-3265.

WINTER NOTICE PROVISIONS (between December 1 – March 31)

- **If your income is at or below 250% of the federal poverty guidelines you may qualify for special protections from termination.** Add together the monthly income of the adults in your household. If that number is the same or less than the amount listed in the chart below for your household size, call us immediately at 1-800-276-2722. You may need to provide us with proof of your income.

Monthly Income at 250% of Federal Poverty Level: 2025					
Household Size	1	2	3	4	Add $1,146 for each additional household member.
Monthly Income	$3,260	$4,406	$5,552	$6,698	

- **If we shut off your service during the winter months (between Dec.1 – Mar. 31)** we will restore your service within 24 hours of your meeting all requirements/conditions to have service reconnected. Where street digging is required it may take up to 7 days.

IMPORTANT INFORMATION

- If you currently have a valid Protection From Abuse order from a court your service cannot be terminated during the winter without PUC permission. There are some additional protections available to you. **Call us immediately at 1-800-276-2722.** (You will be required to provide us with a copy of the order.)
- You may be required to pay more than the amount listed on the front of this notice to have your service turned back on. You may have to pay any additional bills that have become past due.
- You may be eligible for a payment agreement or special assistance programs such as the UGI Customer Assistance Program (CAP). CAP offers a personalized monthly payment and provides bill and debt forgiveness with on-time payments. To apply for CAP, you will need to provide proof of household income and identification. To see if you are eligible, **visit ugi.com/CAP or call us at 1-800- 276-2722.**
- You may be eligible to pay the full past due amount on the most recent payment agreement.
- If your landlord pays your utility bill: You have certain legal protections. Please call us at 1-800-276-2722.
- If you have trouble understanding or speaking English or have a disability please call us at 1-800-276-2722 for free interpretation.
- Termination of service may result in extensive property damage. You are responsible for taking all steps necessary to protect the property and the occupants. You may want to turn off your water so that the pipes do not freeze. If you do not own the property, you are responsible for notifying your landlord that the service is turned off.
- All adult occupants of the premise whose names are on the mortgage, deed, or lease are considered the 'customer' and are responsible for payment to restore service.
- ANY adult occupant who has been living at the premise may have to pay all or portions of the bill to have service restored.

IMPORTANT SAFETY INFORMATION

- For heating purposes use only equipment that is made for home heating. Use all types of heaters carefully and follow all directions for safe use. NEVER use your oven, grill or clothes dryer to heat your home. This could cause a fire or dangerous carbon monoxide gas.
- Please be aware that using candles, portable heaters, or generators may also be dangerous.

Atención ! Este es en mensaje muy importante. Si usted no lo entiende, favor de llamar al 1-800-276-2722.

0-01-096 Rev 2/25

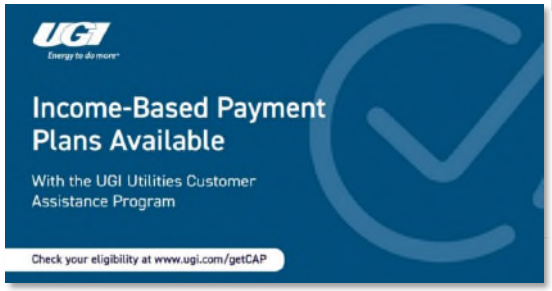
UGI Gas Exhibit BJM-20R

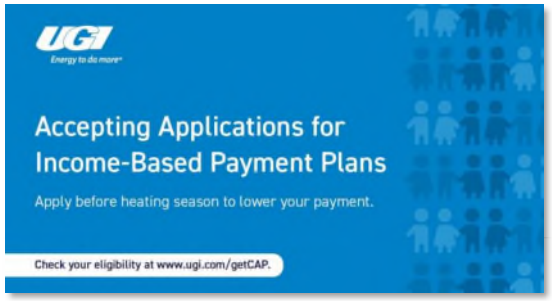
Direct Mail

A three-part 6” x 11” direct mail postcard series will focus on a clear, compelling message regarding CAP program benefits and how a recipient can quickly and easily determine their eligibility.

Will be sent to approximately 40-45k customers on Experian list targeting customer households in zip codes with high low-income saturation.

Call-to-Action:
Direct customers to visit the CAP Eligibility Landing Page to confirm their eligibility for enrollment.





Energy to do more®

UGI Gas Exhibit BJM-21R

UGI Utilities, Inc. – Gas Division Docket No. R-2025-3059523

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON OCA – SET I

29) Reference OCA Statement 6, page 58, lines 15-17. If Mr. Colton was unable to attend the USAC meeting on December 4, 2025, is he aware that Office of Consumer Advocate was present at that meeting?

Response:

Mr. Colton is aware that Christy Appleby attended the USAC meeting on December 4, 2025.

Sponsored by: Roger D. Colton

Dated: April 27, 2026

UGI Gas Exhibit BJM-22R
(No Public Version Available)

UGI Gas Exhibit BJM-23R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 6 (1-17)
Delivered on April 2, 2026

CAUSE-PA-6-1

Request:

Please specifically describe all instances where UGI informs low income customers about the availability of the exemption from security deposit collection and ability to receive a refund of their security deposit.

Response:

UGI Gas informs low-income customers about the availability of the security deposit exemption and the ability to receive a refund of their security deposit through several touchpoints. When a customer is identified as verified low-income through enrollment in a qualifying program, the customer's account is automatically updated and any held security deposit is released at that time. Customers are notified of this action via their account statement reflecting the deposit return.

Additionally, information regarding security deposit exemptions for low-income customers is made available through UGI Gas's CCRs. For self-reported low income customers, customers are advised that they will be sent a CAP application/waiver letter. Please see CAUSE-PA-6-9.1 (waiver letter) and CAUSE-PA-6-9.2 (email confirmation).

Please reference CONFIDENTIAL Attachment OCA-3-2.4, page 70, for additional procedures related to security deposit exemptions.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Gas Exhibit BJM-24R

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 6 (1-17)
Delivered on April 2, 2026

CAUSE-PA-6-2

Request:

Please provide a copy of any and all current written policies, training materials, and/ or other documents which describe UGI Gas's process of assessing, collecting, and refunding security deposits.

Response:

Please see CONFIDENTIAL Attachment OCA-3-2.4, pages 68-71, for training materials related to the Company's process of assessing, collecting, and refunding security deposits.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Gas Exhibit BJM-25R

UGI UTILITIES, INC. - GAS DIVISION
AVERAGE OPERATION SHARE GRANT
JANUARY 2023 - JANUARY 2026

Attachment CAUSE-PA-2-17(A)
B. J. Meilinger
Page 1 of 1

AVERAGE OPERATION SHARE GRANT				
Calendar Year	**2023**	**2024**	**2025**	**2026 YTD**
January	$ 354.24	$ 313.79	$ 338.06	$ 364.90
February	$ 312.71	$ 367.27	$ 398.92	
March	$ 446.93	$ 390.19	$ 402.72	
April	$ 400.97	$ 385.10	$ 386.85	
May	$ 403.82	$ 431.71	$ 407.74	
June	$ 413.79	$ 387.34	$ 388.17	
July	$ 390.91	$ 367.56	$ 388.99	
August	$ 365.36	$ 383.52	$ 404.89	
September	$ 397.32	$ 345.02	$ 388.61	
October	$ 338.66	$ 313.53	$ 356.64	
November	$ 355.22	$ 351.24	$ 248.72	
December	$ 351.02	$ 307.82	$ 340.02	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 13-R

Rebuttal Testimony of
Daniel V. Adamo

Topics Addressed:	**Compliance with 2025 Rate Case Settlement** **Customer Service** **Credit and Collection Expense**

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI"), as Vice President – Customer Relations. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. In this position, I am responsible for managing all marketing, sales, community relations, communications, and the customer information center for UGI, as well as the customer accounting, credit and collections, customer outreach, and compliance departments. In this role, I oversee regulatory compliance with Chapter 14 of the Public Utility Code, 66 Pa. C.S. § 1401, *et seq.*, related consumer regulations, including Chapter 56 of the Pennsylvania Public Utility Code, 52 Pa. Code § 56.1, *et seq.*, and compliance with generally applicable consumer protection, collection, consumer bankruptcy regulations, and the administration of all Universal Service Programs.

Q. What is your educational and professional background?

A. I graduated from Lehigh University in 1998 with a B.S. in Mechanical Engineering. I started my employment with UGI in 1998. My full resume is attached as UGI Gas Exhibit DVA-1R.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of UGI Gas.

Q. Have you been involved in other proceedings before the Commission?

A. Yes. I testified on behalf of UGI Gas in its purchased gas cost filings in 2008 and 2009 as well as the Company's petition for approval of the Growth Extension Tariff ("GET Gas") Program in 2013. I also testified on behalf of UGI Gas in its 2019 Base Rate Case proceeding at Docket No. R-2018-3006814, in its 2020 Base Rate Case proceeding at Docket No. R-2019-3015162, in its 2022 Base Rate Case proceeding at Docket No. R-2021-3030218, and in its 2025 Base Rate Case proceeding at Docket No. R-2024-3052716. Further, I testified on behalf of UGI Electric in its 2021 Base Rate Case proceeding at Docket No. R-2021-3023618 and in its 2023 Base Rate Case proceeding at Docket No. R-2022-3037368. Please see UGI Gas Exhibit DVA-1R for a complete listing of the proceedings in which I testified and their docket numbers.

Q. Have you previously submitted testimony in this proceeding on behalf of UGI Gas?

A. No, I have not.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to certain portions of the direct testimony submitted by Office of Consumer Advocate ("OCA") Witnesses Jennifer Rogers (OCA St. 2), Barbara Alexander (OCA St. 5), Roger Colton (OCA St. 6), and Zach Teti (OCA St. 7) and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Witness Patrick Cicero (CAUSE-PA St. No. 1). Additionally, I will also respond to Office of the Small Business Advocate ("OSBA") Witness Mark Ewen (OSBA St. No. 1). In particular, my rebuttal testimony will address allegations and recommendations concerning the Company's compliance with its 2025 Rate Case Settlement, UGI Gas's customer service, and the Company's credit and collection expenses.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits DVA-1R through DVA-5R.

II. <u>COMPLIANCE WITH 2025 RATE CASE SETTLEMENT</u>

Q. OCA Witness Barbara Alexander summarizes the Company's compliance under the 2025 Rate Case Settlement related to customer service and consumer protections and then alleges that the Company has failed to comply with various provisions, that she cannot evaluate compliance due to timing, or that some of the deadlines for commitments had not yet come to pass when the case was filed. OCA St. 5, at pp. 9-19. Before responding to her specific claims, is there any question that UGI Gas has complied with these commitments under the 2025 Rate Case Settlement?

A. No. Please see UGI Gas Exhibit DVA-2R, which is the internal tracking project management tool that the Company has utilized to maintain compliance with all the

customer service related items required by the UGI Gas 2025 Rate Case Settlement. To date, the Company has completed all required items on time. On pages 9-11 in Witness Alexander's testimony, she questions UGI Gas's compliance on these settlement items. She focuses on the Company's performance compared to other utilities, but per the UGI Gas 2025 Rate Case Settlement, there is no question that the Company met its call center metrics when comparing 2024 to 2025. See UGI Gas Exhibit DVA-3R for a comparison of the results in 2024 and 2025. In addition, in 2024, UGI Gas had very similar results to Peoples Natural Gas Company LLC ("Peoples"). Peoples is the closest size utility in terms of number of customers served with respect to Grade of Service ("GOS"), which is the percentage of calls answered within 30 seconds and abandonment rate.

Q. Could you please respond to Witness Alexander's claims regarding the Company's call center performance, including her concern about the alleged variability in call abandonment rates from month to month and her assertion that the Company has not complied with its "soft" obligation to continue its 2024 call center performance results? OCA St. 5, at pp. 12-13.

A. Witness Alexander's position should be rejected. Although there may be month to month variability in performance, Witness Alexander apparently overlooks how UGI Gas staffs accordingly to reduce customer impact during high call volume times but not to be over staffed during periods where call volumes are lower. Traditional months where increased call volumes are experienced are in October/November, due to customers' efforts to retain gas service before the winter moratorium, and March/April, to prevent shut off for non-payment after the winter moratorium. Witness Alexander calls out three months of

abandonment rate data and then compares those numbers to the 12-month average in 2024. However, when you properly compare the month to month variance from 2024 to 2025, the Company actually outperformed 2024's statistics in 2 of the 3 months. Table 1 below provides a comparative abandonment rate analysis, which also includes the Fiscal Year 2026 results thatAdditionally, the 4.4% abandonment rate experienced in 2024, which is the 2025 Rate Case Settlement target for comparison in 2025, resulted in a 4.7% abandonment rate. Based on comparing the 12 months of data for 2024 versus 2025 using a paired t-test,[1] the abandonment rate has not meaningfully changed year-over-year. Further, the actual year-over-year variance amounts to less than one call per hour difference.

Table 1 – Abandonment Rate Selected Months for 2024 - 2026

Month/Year	Abandonment Rate (%) FY24	Abandonment Rate (%) FY25	Abandonment Rate (%) FY26
October	12%	7.8%	9.6%
November	14.6%	4.6%	7.5%
February	3.8%	6.1%	4.9%
Full Calendar Year Rate	4.4%	4.7%	n/a

[1] "Paired T-Test": A paired t-test is widely-used statistical method to compare the averages of two related groups to determine if the variance is real due to some underlying factor and not due to random chance.

Q. Witness Alexander also states that the Company has "not yet" complied with its Universal Service Advisory Committee ("USAC") reporting requirements under the 2025 Rate Case Settlement. OCA St. 5, at p. 14. Do you have anything to add?

A. The Company recently completed its submission for the Commission's annual Customer Service Performance Report at the end of March. The Company has subsequently submitted the year over year comparison report to OCA, OSBA, CAUSE-PA, and the Commission's Bureau of Investigation and Enforcement ("I&E") at the end of April 2026, which should be a reasonable period of time after the data's submission to the Commission. As Witness Alexander notes in her testimony, the Company does plan to review the results in the next USAC meeting tentatively scheduled for June 2026. Therefore, while it may be true for her to say that the Company has "not yet" complied with its USAC reporting requirement, UGI Gas is on track to do so on time.

Q. Do you have any comment on Witness Alexander's testimony regarding the Company's commitment to complete a root cause analysis for certain complaints? OCA St. 5, at pp. 16-17.

A. Yes. As demonstrated in the Company's response to discovery request OCA-9-16, material progress has been made towards this commitment. Since August 2025, a cross-functional team has: (1) worked to document the end-to-end complaint handling process and addressed process gaps; (2) aggregated and analyzed historical data to optimize record categorization and trend tracking; (3) developed a dashboard for monitoring; and (4) drafted preliminary Apparent Cause Analysis ("ACA") and Root Cause Analysis ("RCA") forms to be tested against identified scenarios. The Company is on track to deliver a report

to CAUSE-PA, the Commission on Economic Opportunity ("CEO"), I&E, OCA, and OSBA describing UGI Gas' progress and the results of its review and implementation of the RCA and/or ACA process on or before October 1, 2026.

Q. Witness Alexander acknowledges that the Company has developed a written confirmation of a payment arrangement but nonetheless asserts that the document is "defective in that it does not include any notice of customer rights and should be revised to do so, including the right to dispute the terms of the payment arrangement with UGI Gas and, if not satisfied, how to file an informal complaint to the Commission." OCA St. 5, at p. 17. Do you agree?

A. No. Paragraph 87 of the Settlement states the following: "UGI Gas agrees to develop and implement a written communication to confirm the terms of initial and substantially modified payment agreements upon conclusion of a customer's oral agreement to terms. This will be implemented by April 1, 2026." It says nothing about including a notice of customer rights in the written communication. Therefore, the Company has complied with the actual terms of the 2025 Rate Case Settlement.

Q. Please respond to Witness Alexander's testimony about the Company's revised customer communications and training materials related to the Weather Normalization Adjustment ("WNA"). OCA St. 5, at pp. 17-18.

A. Witness Alexander states that "[a] significant omission in these communications is a presentation of the historical incremental charges and/or credits imposed on customers as a result of this program." However, Paragraph 58 of the UGI Gas 2025 Rate Case

Settlement required all parties to review and provide input on the letter prior to it being programmed and implemented within UGI Gas's Customer Information System ("CIS"). OCA provided feedback on the letter, which UGI Gas largely accepted. None of the concerns being raised by Witness Alexander now were provided in OCA's comments. Due to the complexity of the inputs and changes in the customer letter, the Company's Information Technology ("IT") team is currently working through the required system changes. Implementation is targeted to coincide with the first bill that will contain WNA in the Fall of 2026, and Customer Service Representative ("CSR") training will be completed prior to the letter being available to send via the Company's CIS.

Q. Although Witness Alexander acknowledges that the Company has moved the presentation of the Price to Compare ("PTC") to the front of the bill, she asserts that the terms used to describe the "natural gas Price to Compare" and the supplier's "commodity charge" should "be the same so that the customer can more directly relate the PTC to the NGS's charges on the customer bill." OCA St. 5, at pp. 18-19. Do you agree?

A. No. First, Witness Alexander admits that the Company complied with Paragraph 66 of the 2025 Rate Case Settlement to move the PTC from the back of the bill to the front. Second, I disagree with Witness Alexander's request that the Company change PTC or the supplier's "commodity charge." The PTC is a well-established and widely utilized term in the Commonwealth that is consistently used by the Commission and other utilities, and understood by customers. Additionally, the definitions of Commodity Charge, Purchased Gas Adjustment and PTC are on the back of the customer's bill under Explanation of Terms

so that any customer that is not familiar with these terms has immediate access to the explanation.

Q. Please address Witness Alexander's testimony about UGI Gas's implementation of alternative methods for bill payment, including her claim that the Company failed to implement the ability to pay by Venmo or Apple Pay by the September 30, 2025 deadline. OCA St. 5, at p. 19.

A. The Company has complied with Paragraph 68 of the UGI Gas 2025 Rate Case Settlement. Witness Alexander bases her position entirely on the Company's "public website" purportedly not "mention[ing] the ability to pay via Venmo or ApplePay [sic]." In actuality, the Company implemented Apple Pay on July 16, 2025, and Venmo on September 11, 2025, both of which pre-dated the September 30, 2025 deadline under the Settlement. Customers could use these payment options when making a one-time payment beginning on those respective dates. Please see Table 2 below for customers that made payments via Apple Pay and Venmo once the methods were available. Additionally, the website shown in UGI Gas Exhibit DVA-4R is a copy of the Company's webpage showing the current payment options.

Table 2 – Customer Payments made via Apple Pay and Venmo

Month	Apple Pay	Venmo
July 2025	188	n/a
August 2025	340	n/a
September 2025	446	19
October 2025	504	16
November 2025	504	12
December 2025	525	18
January 2026	564	22
February 2026	603	26
March 2026	842	21
Total	4,516	134

The remaining payment options – PayPal, and PayPal Credit, were implemented in May 2026. Google Pay is currently on track to be moved to production for customers to use it by the end of May to early June of 2026. The Company's payment vendor no longer supports Amazon Pay, so that service cannot be implemented. Once the remaining three payment options are implemented fully, the Company will be using all options provided by its payment vendor. The Company will continue to add more options as the vendor makes more available. I note that there was no specified implementation date for the other payment options, specifically, Google Pay, PayPal, and PayPal Credit, under Paragraph 68 of the UGI Gas 2025 Rate Case Settlement. The Settlement only specifies that they would be implemented "on a phased-in approach to allow time for proper testing of each option."

As such, Witness Alexander's testimony on page 19 that "it is not clear if the required date for implementation was met for all these new payment options" does not accurately describe the Settlement.

Q. Do you have any final observations about Witness Alexander's testimony on these subjects?

A. I do. My testimony clearly shows that the Company has complied to date with all customer service-related items in the UGI Gas 2025 Rate Case settlement and is on track to continue meeting obligations as agreed upon. I would again refer to UGI Gas Exhibits DVA-2R and DVA-3R highlighting those commitments and the actions taken by UGI Gas to comply with the Settlement. Moreover, on page 20, lines 1-14 of her direct testimony, where Witness Alexander states UGI Gas is not meeting the 2025 Rate Case Settlement commitments, she is advocating for new proposals that were not part of the commitments made in the 2025 Rate Case Settlement. UGI Gas cannot be expected to comply with terms that were not included in the Settlement and reflect an expansion on the specific wording of the terms. As such, it is incorrect to suggest that the Company failed to comply. Therefore, Witness Alexander's positions and recommendations should all be rejected.

III. CUSTOMER SERVICE

A. CALL CENTER PERFORMANCE

Q. In addition to her testimony about the Company's call center performance related to the 2025 Rate Case Settlement, OCA Witness Alexander recommends "that the current internal UGI performance metrics for call centers that [she] ha[s] identified be formally adopted and required by the Commission to ensure that UGI Gas'

internal performance requirements are maintained and not allowed to deteriorate." OCA St. 5, at p. 22. Please respond.

A. The Company already submits customer service performance metrics on an annual basis to demonstrate compliance against a standard. While the Company is pleased that Witness Alexander positively recognizes and supports the Company's efforts, these are internal performance metrics to measure management quality, which is already evaluated through the periodic Management Efficiency Audits in which the Company participates. As such, her proposal is not necessary.

B. SHOPPING CUSTOMERS

Q. OCA Witness Alexander recommends that the Company "adopt additional and more targeted customer communications to assist customers in ensuring affordability for basic natural gas service due to high NGS charges that appear on the customer bill that UGI collects under threat of termination of service." OCA St. 5, at p. 9. What recommendations does she make specifically?

A. Witness Alexander recommends that UGI Gas: (1) "eliminate [its] prominent statement in the bill insert materials that retail choice may have the potential to 'save'"; (2) "include information in its FAQs and customer bill inserts about the right to choose and explain that the risk of higher prices is documented and how to avoid higher prices and bills"; (3) "explain how to shop and compare NGS prices during the entire term of the contracts and alter customers to the potential for a change in the NGS price after any initial promotional price and how NGS variable rates can reflect volatile changes in the wholesale market"; and (4) "develop targeted communication to customers with NGS charges that increase significantly over the PTC to alert them to compare that price to the PTC and include a

calculation that documents this difference in the customer's recent bill(s)." OCA St. 5, at p. 25.

Q. What is the Company's position on these recommendations?

A. The Company complies with the Commission's bill format regulations and has moved the price to compare section of the bill from the second page to the first page to make it more prominent for customers to view. UGI Gas also has call scripts to respond to customer's questions on choice and, as shown in the attached UGI Gas Exhibit DVA-5R, has a dedicated website page educating customers on the ability to shop and providing additional resources, such as PA Gas Switch. Lastly, concerning Witness Alexander's recommendation that UGI Gas "develop targeted communication to customers with NGS charges that increase significantly over the PTC to alert them to compare that price to the PTC and include a calculation that documents this difference in the customer's recent bill(s),"[2] there would be costs associated with programming a system alert and communications to be sent to customers when their supplier cost is above the current PTC. The Company estimates that the IT costs to program a price to compare alert versus the customer's current choice supplier rate would be approximately $150,000.

[2] OCA St. 5, at p. 25.

C. SOCIAL SECURITY NUMBERS

Q. Could you please provide an overview of OCA Witness Colton's claims regarding the Company's use of Social Security Numbers ("SSNs")?

A. Witness Colton asserts that the Company should refrain from or be prohibited from the future collection of SSNs from its customers due to the rise in identity theft. OCA St. 6, at p. 65. Among other things, Witness Colton argues that SSNs are not good authenticators for the purpose of reducing fraud and points to guidance from the Office of Management and Budget ("OMB"), the Federal Trade Commission ("FTC"), and the Task Force on Identity Theft as support for reducing the use of SSNs. OCA St. 6, at pp. 65-70, 75. He also claims that the Company lacks information about best practices regarding SSNs and that UGI Gas does not inform or notify customers about the intended retention and use of SSNs at the time the SSNs are requested. OCA St. 6, at pp. 70-74. Additionally, Witness Colton raises concerns about the sharing of customer data within the UGI corporate structure beyond UGI Gas. OCA St. 6, at pp. 74-75. Therefore, he recommends that the Commission direct UGI Gas to "report to the Commission, within 12 months of a final decision in this docket, its plan to eliminate the collection and retention of customer Social Security Numbers" and that "[t]his plan should include a plan for elimination of the SSNs currently retained in Company information technology." OCA St. 6, at pp. 75-76.

Q. What is your response?

A. To clarify, the Company asks for a new customer's SSN when they apply for service so that an Experian check can be run to verify their identity. If a customer does not wish to provide their SSN, they are able to provide their driver's license number as an alternative. Regarding enrollment for the Company's Universal Service Programs, SSN was previously

requested. However, pursuant to Paragraph 59(a) of the 2025 Rate Case Settlement, the Company agreed to implement the Commission's Common Application Form and is utilizing it for its Customer Assistance Program ("CAP") and Operation Share as of December 2025. This form does not include a request for SSN. Additionally, an SSN is requested, but not required, on the Low Income Usage Reduction Program ("LIURP") application. This information is used for validation in the event the Company finds that the same household members are listed in applications for separate properties. Further, Witness Colton raises concerns about the sharing of customer data within the UGI corporate structure beyond UGI Gas. OCA St. 6, at pp. 74-75. The Company does not share customers' SSNs with affiliates or corporate entities. The standards and policy programs for safeguarding customer personal information are what is shared across business units. Finally, Witness Colton provides no specific recommendations about what should replace the use of SSNs. Thus, his recommendation is incomplete and does not require Commission action.

D. TERMINATION OF SERVICE

Q. CAUSE-PA Witness Cicero recommends that the Company amend Rule 9 of its retail tariff governing termination and disconnection of service, such that the Company provide at least 10 days' written notice of termination (as opposed to "reasonable notice"). CAUSE-PA St. No. 1, at p. 92. Does the Company agree with this recommendation?

A. Yes.

Q. Witness Cicero also proposes that the Company be required to remove "violation of tariff Rules and Regulations" as a ground for termination with notice, asserting that such provision is "overly broad" and is "not authorized by existing PUC regulations of the Public Utility Code." CAUSE-PA St. No. 1, at pp. 92-93. Please respond.

A. I am advised by counsel that this issue will be further addressed in the Company's briefs. However, UGI Gas maintains that its existing, Commission-approved tariff is lawful. Counsel advises me that the Commission's regulations do not function as an absolute limit on the grounds for which UGI Gas can terminate customers' service with notice. Additionally, other utilities' Commission-approved tariffs contain similar language. For example, Peoples's tariff states that it can terminate gas service for "failure to comply with or violation of Tariff Rules and Regulations." Peoples Tariff Rule 5, Supp. No. 2 to Gas – Pa. PUC No. 48, First Revised Page No. 24. Likewise, PECO Energy Company – Gas Division's ("PECO Gas") tariff provides that it can terminate service "for other violation of these Rules and/or applicable Commission rules in accordance with the Pennsylvania Public Utility Code or the Commission's regulations." PECO Gas Tariff Rule 17.2, Gas-Pa. P.U.C. No. 6, Original Page No. 27. Some examples where termination of service is required without notice or with limited notice include the following: customers that are in violation of the Company's tariff and create a safety risk for the customer, others, and/or the Company's property; tampering of meter and Company equipment; theft of service; and not allowing access to inspect the Company's facilities as required by regulations.

E. SMALL BUSINESS PAYMENT PLANS AND OTHER OSBA RECOMMENDATIONS

Q. Have you reviewed OSBA Witness Ewen's testimony?

A. Yes.

Q. What recommendations does Witness Ewen make?

A. Witness Ewen notes that UGI Gas offers small business customers payment plans for up to 6 months. OSBA St. No. 1, at p. 3. He recommends that the Company implement a formal mechanism to track interactions in which small business customers report financial difficulties (e.g., trouble paying heating bills on time), including both participation in the Company's existing late payment plan and more informal complaints or inquiries. OSBA St. No. 1, at p. 3. Witness Ewen notes that these interactions should be tracked annually and categorized by the customer's respective rate class (Rate N, Rate DS, etc.). OSBA St. No. 1, at p. 3. He also recommends that UGI Gas provide the OSBA's contact information and a description of the services the OSBA offers on the Company's website. OSBA St. No. 1, at p. 3.

Q. Do you have any response to these recommendations?

A. The Company currently complies with all regulatory filing requirements with the Commission for customer-related data and performance and, therefore, does not believe additional metrics should be required. However, the Company does agree with the proposal to include OSBA's contact information and a description of OSBA's services on the Company's website.

IV. CREDIT AND COLLECTION EXPENSES

Q. Does OCA Witness Colton make any proposals with respect to UGI Gas's credit and collection expenses?

A. Yes. Witness Colton recommends that "there be a fifty-fifty sharing of the credit and collection expenses which UGI Gas proposes to include in its cost of service." OCA St. 6, at p. 4.

Q. What are the purported reasons for Witness Colton's recommendation?

A. Witness Colton points to Section 523 of the Public Utility Code as support for adjusting the Company's claimed cost of service based on alleged "inefficiency and ineffectiveness of the UGI Gas expenditures" in this area. OCA St. 6, at p. 50. According to Witness Colton, UGI Gas's current credit and collection techniques and efforts are ineffective because the Company: (1) does a poor job of responding to unaffordability issues faced by low-income customers; (2) allows customers to fall into debt; (3) fails to reconnect service; and (4) writes off a higher percentage of revenue. *See* OCA St. 6, at pp. 41-47. Witness Colton also claims that UGI Gas relies on "unrealistic agreements" instead of identifying low-income customers and enrolling them in CAP. OCA St. 6, at pp. 47-50.

Q. Do you agree with Witness Colton?

A. Absolutely not. Witness Colton asserts that "[w]hatever collection activity UGI Gas is directing toward Confirmed Low-Income customers is evidently not working." OCA St. 6, at p. 44. The Company has repeatedly explained that collection practices are consistent with the requirements of 52 Pa. Code § 56.93–56.100. These practices include numerous

attempts by mail, phone calls and in-person field visits. Further, aside from suspending terminations for nonpayment from December 1 through March 31 for confirmed low-income customers, no separate or differentiated collection activities are conducted across customer types. Witness Colton also implies that the Company resorts to termination more frequently than it should for confirmed low-income customers, when less than 10% of the 114,129 notices sent in 2025 to customers eligible for termination due to nonpayment resulted in the disconnection of service of that customer population. Further, the Company worked with those customers to restore service and, through those efforts, was able to restore service to 99.6% of those customers. As described in the testimony provided by UGI Gas Witness Meilinger, the Company has been diligent and successful in its attempts to provide outreach to vulnerable customers, expanding its tactics and programming each year.

Q. Based on Witness Colton's recommendation, OCA Witness Rogers proposes to decrease the Company's credit and collection expenses by $3.097 million, claiming that UGI Gas could not provide the exact dollar amount for the expense and, as a result, 2025 should be used as a proxy for purposes of calculating the 50% reduction in the credit and collection expenses. OCA St. 2, at pp. 15-16. Do you agree with this proposal?

A. No. The Company did not say that it was unable to provide an exact dollar amount in its response to OCA-15-5; rather, UGI Gas explained why collection expenses calculated for annual compliance reporting are not comparable to its cost-of-service study, as requested. The Company did provide an exact dollar amount and an itemized listing of the credit and

collection expenses in Attachment OCA-15-7. The Company takes a comprehensive approach to compiling these expenditures annually, pursuant to 52 Pa. Code § 62.5, and includes company wages and labor across front and back office functions and dispatching and field operations; costs associated with all required notices and communication; third party collection agency and bankruptcy costs; and expenses associated with winter survey, as prescribed in the regulation. Further, OCA's proposed disallowance would simply ignore costs substantiated by record evidence and legitimately incurred by UGI Gas to undertake necessary functions on an incorrect premise. As such, OCA's proposal should not be adopted.

V. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit DVA-1R

Daniel V. Adamo
Vice President Customer Relations

Work Experience

UGI Utilities, Inc., Reading, PA

August 2021 – Current	Vice President Customer Relations
August 2018 – July 2021	Director Customer Service
January – August 2018	Senior Manager Billing & Compliance
2016 – 2018	Functional Lead – UNITE Project
2015 – 2016	Manager Operations
2013 – 2015	Director Marketing (Programs and Strategy)
2011 – 2013	Business Development Director
2009 – 2011	Regional Marketing Manager
2007 - 2009	Manager Rates
2005 - 2007	Project Engineer Gas Supply
2004 – 2005	Project Engineer Key Accounts
2001 – 2004	Staff Engineer New Business
2000 – 2001	Customer Service Supervisor
1998-2000	Engineer 1

Previous Testimony

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2008-2039284 2009

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2009-2105904 2009

UGI Central Penn Gas Purchased Gas Cost Filing: Docket No. R-2009-2105909 2009

UGI Utilities – Gas Division Purchased Gas Cost Filing: Docket No. R-2009-2105911

UGI Growth Extension Tariff Pilot Programs Filing: Docket No. P-2013-2356232

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2018-3006814

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2019-3015162

UGI Utilities, Inc. Electric Division Base Rate Increase Filing: Docket No. R-2021-3023618

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2021-3030218

UGI Utilities, Inc. Electric Division Base Rate Increase Filing: Docket No. R-2022-3037368

UGI Utilities, Inc. Gas Division Base Rate Increase Filing Docket No. R-2024-3052716

Education

B.S. in Mechanical Engineering from Lehigh University, 1998

UGI Gas Exhibit DVA-2R

	2025 Base Rate Case Settlement Paragraph	Customer Service 2025 Base Rate Case Settlement Mandates and Tasks (Language from Settlement Document Shown in Note)	USAC Input/ Meeting	Deadline Gray font indicates internal deadline	Status (Not Started / On Track / At Risk / Completed / Overdue)
Customer Assistance					
USP		**Common Application**			
	59a/66c	Adopt PUC Common Application, including a checkbox to indicate pursuing returning to default service		12/10/2025	
		Produce ADA Compliant Version of form, including a checkbox to indicate pursuing returning to default service		12/10/2025	
		Replace CAP application on the website with the new common application		12/10/2025	
		Replace CAP application in Security Deposit Waiver US Mail with Common Application		12/10/2025	
		Develop Terms and Conditions/Form Instructions, which include returning to default service if on CHOICE		12/10/2025	
		SAP CRB Enhancement to suspend collections for 45 days for customers leaving Choice to enroll in CAP.		12/10/2025	
		Develop business process and script for CAP referrals on Choice		12/10/2025	
		Introduce Common Application as a replacement for the current CAP Application		12/10/2025	
		DHS Data Sharing Opt-In			
	59b	Auto-recertification CAP customers who receive LIHEAP AND/OR consents to data sharing		10/28/2025	
		Develop process to automatically recertify customers for CAP if customer consents to data sharing		10/28/2025	
		Test/evaluate the communication being sent to the auto recertified customers to ensure compliance with data sharing order		10/28/2025	
	59c	Update procedures to waive income-verification for enrollment in CAP, LIURP and/or Op Share with DHS data sharing OR LIHEAP in prior season		10/28/2025	
CAP		**Enrollment Rules**			
	59d	Quantify impact to Company if auto-enrollment in CAP is mandated		Quarterly in 2026	
		Schedule quarterly working group meetings	X	Quarterly in 2026	
		Program Marketing			
	61a	Develop marketing plan to spend $120K	X	11/1/2025	
		Presentation for USAC Meeting, incorporate any stakeholder feedback	X	11/1/2025	
		Review current CAP webpage for content consistency across all materials		11/1/2025	
	61b/c	Plan and execute additional WARM events, including 6 in Lancaster, 3 in Williamsport and 4 in Wilkes-Barre	X	Ongoing in 2026	
		Create WARM event intake form to track attendees, materials distributed at each event		1/1/2026	
	61c	Outreach to Mayor Offices Specified		12/31/2026	
		Develop cover letter to offer meetings and share WARM events + new brochure		12/31/2025	
		Develop slide deck that can be used to present at meetings and events		12/31/2025	
		Letter Updates			
	66b	COS Enhancment to update CAP removal letter to remove the first bullet and amend CHOICE bullet	X	Unspecified	
	--	Generate standard denial letter which reflects changes mandated in 66b	X	Unspecified	
	--	Revise CAP application, welcome, renewal letters to be more customer friendly and mention application changes		Unspecified	
LIURP		**Spending**			
	60a/b/c/d/e	Develop plan to increase budget by $1MM, including contigency to rollover into 6 months of following year		12/31/2025	
Op Share		**Spending**			
	62a/b	Develop plan to increase budget by $500K, including contigency to rollover into 6 months of following year		9/30/2025	
Billing					
Billing Components		**WNA**			
	58a	Enhance customer communications for WNA		Unspecified	
		Revise WNA SAP Ad Hoc letter to be customer and billing-period specific - Input provided by OCA, I&E, CAUSE-PA, OSBA	X	12/31/2025	
		Revise website language to be more customer-friendly	X	12/31/2025	
		Update call center scripts and training materials to reflect no WNA charges to May and affected CLI CAP		10/31/2025	
	58c	Remove WNA charges from CLI CAP customers on a % of income bill		10/31/2025	
	58b	WNA will no longer be applied to May Bills		10/31/2025	
		Reconnect Fees			
	64	SAP CRB Enhancement to reverse reconnection fees upon income-verification of 150% FPL		10/31/2025	
		Update Security Deposit Waiver letter to include reconnection fee language. Improve language to be plain text.		10/31/2025	
		Update Denial of Service letter to include reconnection fee language.		10/31/2025	
		Update Fiori Move-In Auto Email to include this language		10/31/2025	
		Create new BPEM Case for reversal failures, include "Get Work" button		10/31/2025	
		Create job aid for new BPEM case for Billing		10/31/2025	
		Update scripts to specify time period alloted to verify income - Gas Only		10/31/2025	
		Propose tariff language for time period alloted to verify income		10/31/2025	
		Security Deposits			
	65a	SAP CRB enhancement to refund security deposits to income-verified below 150% customers in form of check or ACH		10/31/2025	
		Update Call Center Scripts to reflect security deposit changes		10/31/2025	
	65b	Develop procedure to reverse security deposit refund check if returned as undeliverable and apply bill credit.		10/31/2025	
		Price to Compare			
	66a	SAP CRB Enhancement to move PTC from end of bill to Page 1		3/30/2026	
		Review external-facing communications that have a bill sample and coordinate update		5/30/2026	
Payments		**Payment Options**			
	68	Offer additional electronic payment options			
		Implement ApplePay		9/30/2025	
		Implement Venmo		9/30/2025	
		Implement PayPal and PayPal Credit		Phased in Implementation	
		Implement Google Pay		Phased in Implementation	
		Implement Amazon Pay		Phased in Implementation	
	69	Coordinate UGI absorbing authorized walk-in site fees		3/30/2026	
		Review and revise FISERV contract		9/30/2025	
		Update website and scripts to remove reference to fees		3/30/2026	
		Payment Arrangements			
	70	SAP CRB enhancement for 6 month Rate N/NT payment arrangement		10/28/2025	
		Update call center scripts for offering Rate N/NT payment arrangements (budget billing should be addressed)		10/28/2025	
		Update ad hoc report for incorrect IPs to include NR installment plan type		10/28/2025	
	87	SAP CRB enhancement to send written payment arrangement terms		4/1/2026	
Customer Service					
Call Center		**Performance**			
	67d + others	Schedule USAC Meetings to review progress	X	Various	
	82	Track and report on annual Quality of Service Stats vs 2024	X	Ongoing	
	83	Prepare YoY reporting for stakeholders	X	5/1/2026	
		Scripts and Training Changes			
		Change in Income/Circumstance training materials to create SME ticket for Level 1 (Outreach to update ZLOWCE)			
	67c	Review existing dunning communications to inform customers of option to enroll in CAP and details		10/28/2025	
		Coordinate update of doorhangers with Print Shop		10/28/2025	
	67c	Update call center scripts to inform customers of option to enroll in CAP and details		10/28/2025	
	67e	Update call center scripts to educated customers on USP (roll out upon USAC approval)	X	10/28/2025	
	84	Create new training materials for field representatives regarding personal contact with customers prior to disconnection		3/31/2026	
Compliance		**Dispute Tracking**			
	86	Create, document and implement PUC Complaint tracking, analysis and reporting plan		9/30/2026	
		Document current processing customer disputes and PUC Complaints		8/22/2025	
		Develop future state for processing customer disputes and PUC Complaints		3/1/2026	
		Review existing report SAP BOBJ for accuracy and request any needed changes		1/1/2026	
		SAP CRB enhancement to collect new data for tracking		4/1/2026	
		Develop apparent cause evaluations process		6/1/2026	
		Draft annual report describing progress and results		10/1/2026	
Low Income Reporting		**Definition**			
	67a	SAP Enhancement to change ZLOWCE indicator to exclude >150% FPL	X	12/31/2025	
		Data cleanup to update ZLOWCE when > 150% FPL		12/31/2025	
		Data cleanup to scrub stale LOW_INCOME_LVL, both live tables and BW/BI Reporting		12/31/2025	
		Update call center scripts to update "confirmed low income" reference to "income verified"		12/31/2025	
		Tracking			
	61di	Track and report on number of nonpayment disconnections of PUC CLI		Unspecified	
	61dii	Track and report on number of payment troubled PUC CLI customers		Unspecified	
	61diii	Update CWIP reporting to include number of PUC CLI customers		Unspecified	
	61d	Reduction plan to reduce payment troubled and disconnected CLI	X	Unspecified	
Website		**HomeServe**			
	85a	Update website language to advise customers that HomeServe products are optional and not endorsed by UGI		Unspecified	

UGI Gas Exhibit DVA-3R

UGI UTILITIES - GAS DIVISION
CUSTOMER SERVICE ANNUAL PERFORMANCE REPORT
CALENDAR YEARS 2024 AND 2025

COMPANY-REPORTED PERFORMANCE

A. Telephone Access	UGI GAS 2024	UGI GAS 2025	Columbia 2024	NFG 2024	Peoples 2024	PGW 2024
	%	%	%	%	%	%
1. Busy-Out Rate	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%
2. Call Abandonment Rate	4.0%	4.7%	2%	1%	4%	2%
3. Percent of Calls Answered within 30 seconds	86%	86%	83%	91%	86%	97%

B. Billing	UGI GAS 2024		UGI GAS 2025		Columbia 2024		NFG 2024		Peoples 2024		PGW 2024	
	Count	%	Count	%	Count	%	Count	%	Count	%	Count	%
1. Number/Percent Residential Bills Not Rendered Once Every Billing Period	1	0.00%	0	0.00%	0	0.00%	0	0.00%	17,427	3.10%	3	0.00%
2. Number/Percent Bills to Small Business Customers Not Rendered Once Every Billing Period	1	0.01%	0	0.00%	0	0.00%	0	0.00%	1,328	3.20%	0	0.00%

C. Meter Reading	UGI GAS 2024		UGI GAS 2025		Columbia 2024		NFG 2024		Peoples 2024		PGW 2024	
	Count	%	Count	%	Count	%	Count	%	Count	%	Count	%
1. Number/Percent Residential Meters Not Read by Company or Customer in Six Months	36	0.01%	25	0.00%	6	0.00%	1,037	0.93%	4	0.00%	208	0.04%
2. Number/Percent Residential Meters Not Read in 12 Months	8	0.00%	4	0.00%	1	0.00%	200	0.18%	4	0.00%	71	0.02%
3. Number/Percent Residential Remote Meters Not Read in Five Years	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%

D. Response to Disputes	UGI GAS 2024	UGI GAS 2025	Columbia 2024	NFG 2024	Peoples 2024	PGW 2024
	Count	Count	Count	Count	Count	Count
1. Number of Residential Disputes That Did Not Receive a Response within 30 Days	3	17	0	5	0	21

CUSTOMER TRANSACTION SURVEY

A. Reaching the Company	UGI GAS 2024 (a)	UGI GAS 2025 (b)	Columbia 2024 (c)	NFG 2024 (d)	Peoples 2024 (e)	PGW 2024 (f)	Inudstry Average
Q3: Satisfaction with ease of reaching the Company	86% [f]	84%	86% [f]	85%	86% [f]	82%	85%

B. Automated Phone System	UGI GAS 2024 (a)	UGI GAS 2025 (b)	Columbia 2024 (c)	NFG 2024 (d)	Peoples 2024 (e)	PGW 2024 (f)	Inudstry Average
Q5: Ease of using automated telephone system	76%	77%	80%	NA	76%	80%	78%
Q6: Satisfaction with automated telephone system choices	74%	76%	78%	NA	74%	77%	76%
Q7: Overall satisfaction with automated telephone system	74%	77%	78%	NA	76%	77%	76%
Q9: Satisfaction with time to speak with a representative	81%	83% [c]	78%	83% [c]	79%	82%	81%

C. Company Representatives	UGI GAS 2024 (a)	UGI GAS 2025 (b)	Columbia 2024 (c)	NFG 2024 (d)	Peoples 2024 (e)	PGW 2024 (f)	Inudstry Average
Q10: CSR – Courteous	95%	94%	94%	93%	94%	93%	94%
Q11: CSR – Knowledgeable	91%	90%	92%	90%	92%	92%	91%
Q12: CSR – Overall handling of contact	91%	90%	91%	90%	90%	90%	90%
Q15: Satisfaction – Work completed timely (field)	87%	91%	94%	90%	92%	85%	90%
Q17: Satisfaction – Field rep response time	86%	87%	93% [d]	77%	85%	86%	84%
Q18: Field rep – Courteous	98%	99%	97%	95%	98%	97%	97%
Q19: Field rep – Knowledgeable	92%	93%	92%	92%	96%	96%	94%
Q20: Field rep – Respectful of property	97% [d]	98% [de]	97% [de]	85%	91%	97% [d]	92%
Q21: Field rep – Overall handling	95% [d]	99% [cde]	91%	84%	92%	94% [d]	90%

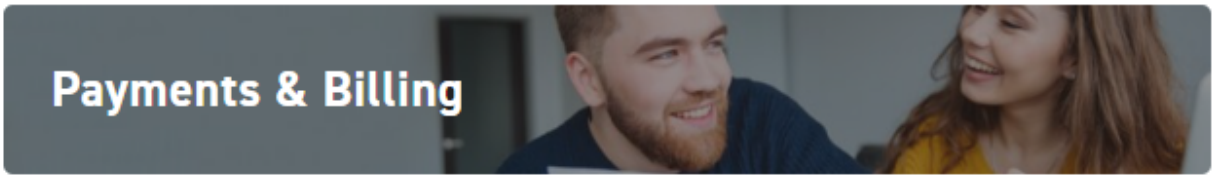
D. Overall Satisfaction	UGI GAS 2024 (a)	UGI GAS 2025 (b)	Columbia 2024 (c)	NFG 2024 (d)	Peoples 2024 (e)	PGW 2024 (f)	Inudstry Average
Q22: Overall satisfaction with quality of service provided	88%	86%	89%	87%	88%	86%	87%

Notes: Survey metric = percent of respondents rating 'Satisfied' or 'Very Satisfied' (Top-4-Box on a 1–10 scale). Peer and industry data for 2025 not yet published by PA PUC.
A letter indicates score is statistically higher than score of company denoted with that letter.

UGI Gas Exhibit DVA-4R

Energy to do more+

Account & Billing | Choose Gas | Safety | Ways to Save | News & Community | Emergency | Translate | Search | Log In



PAYMENTS & BILLING

Pay Your Bill Online

Pay in Online Account Center – Log in to your profile and pay your bill online. Save payment information for faster future payments. Register your account here.

QUICK PAY WITH BANK ACCOUNT - NO SERVICE CHARGE

Pay with Your Bank Account – You will need your UGI account number, zip code, and your routing and account number for your checking or savings account.

QUICK PAY WITH CARD - NO SERVICE CHARGE

Pay with Your Credit or Debit Card – You will need your UGI account number, card number, expiration date, and security code.

QUICK PAY WITH DIGITAL WALLET - NO SERVICE CHARGE

Pay with Apple Pay or Venmo – You will need your UGI account number, zip code and authorized access to your digital wallet.

Other Payment Options

Pay in Person at Authorized Pay Site

You may pay your UGI bill in person at one of the authorized CheckFreePay locations. Be sure to designate UGI as the "biller" when looking up payment options. You will also need your UGI account number. **Paying at an unauthorized payment agent may cause delays in your payment reaching UGI.***

Pay by Phone

Call 800-276-2722 to pay your bill through an automated phone system. You will need your UGI account number during the call.

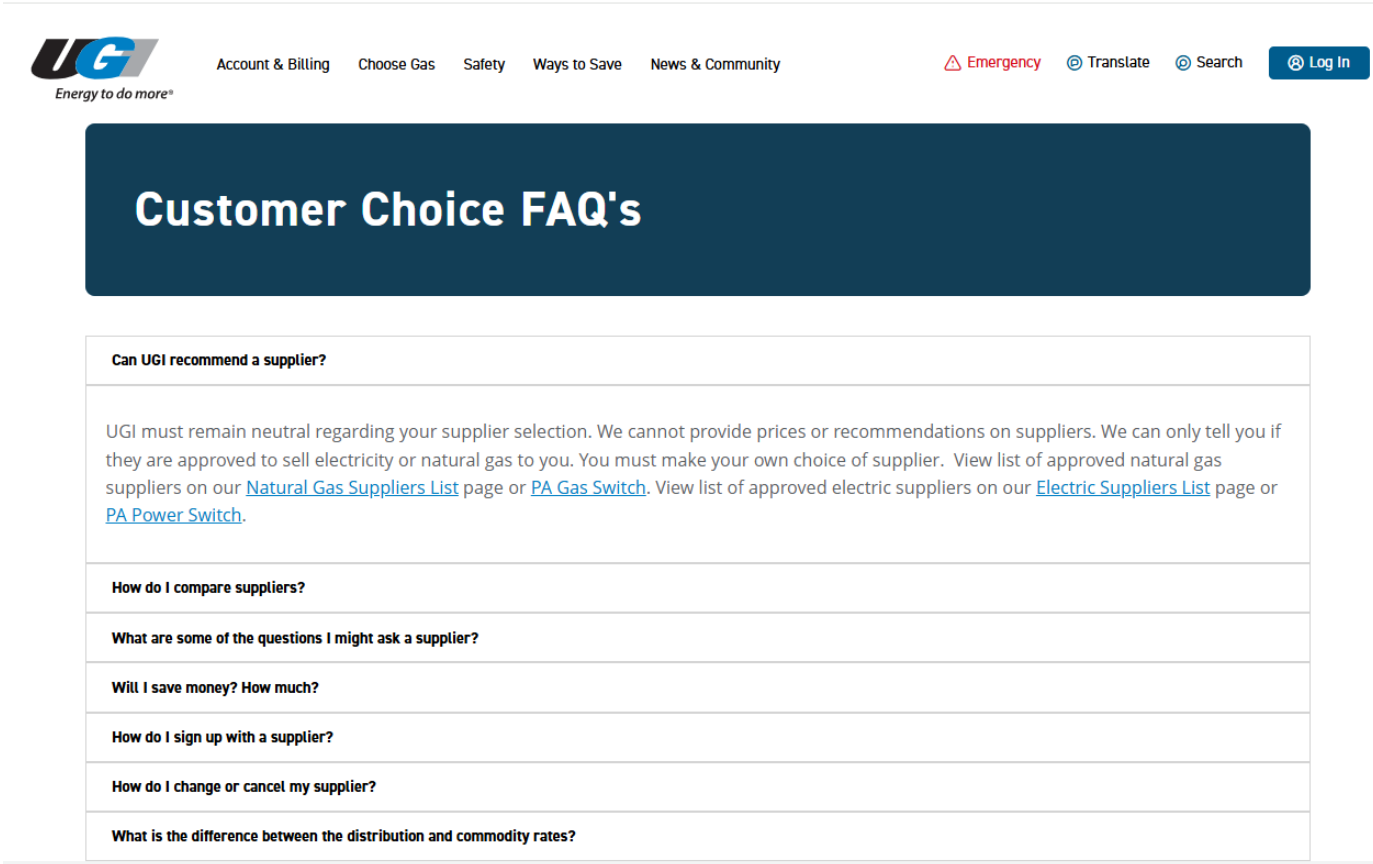
To pay with a credit or debit card, select options 3, 1, 3, 2 after selecting your language preference.

To pay from a bank account Monday-Friday 8AM – 5PM, select options 3, 1, 3, 1 after selecting your language preference.

Pay by Mail

Mail payment with your UGI account number to:
UGI Utilities, Inc.
P.O. Box 15503, Wilmington, DE 19850-5503

UGI Gas Exhibit DVA-5R


Energy to do more®
Account & Billing
Choose Gas
Safety
Ways to Save
News & Community
Emergency
Translate
Search
Log In
Customer Choice FAQ's
Can UGI recommend a supplier?
UGI must remain neutral regarding your supplier selection. We cannot provide prices or recommendations on suppliers. We can only tell you if they are approved to sell electricity or natural gas to you. You must make your own choice of supplier. View list of approved natural gas suppliers on our Natural Gas Suppliers List page or PA Gas Switch. View list of approved electric suppliers on our Electric Suppliers List page or PA Power Switch.
How do I compare suppliers?
What are some of the questions I might ask a supplier?
Will I save money? How much?
How do I sign up with a supplier?
How do I change or cancel my supplier?
What is the difference between the distribution and commodity rates?

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 14-R

Rebuttal Testimony of
Timothy Angstadt

Topics Addressed:
Supplier Notifications
Imbalance Trading and Penalties
Force Majeure
Standards of Conduct

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy J. Angstadt. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to the direct testimony of Christopher Reyes on behalf of the Retail Energy Supply Association ("RESA").

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. Please see UGI Gas Exhibit TJA-1.

II. RESPONSE TO RESA WITNESS REYES

A. SUPPLIER NOTIFICATIONS

Q. Does UGI Gas provide suppliers with notification of pipeline cuts and customer interruptions?

A. Yes, UGI Gas provides suppliers with notification of pipeline cuts and customer interruptions. Customer interruption tiers are posted on the Energy Management Website (EMW) as Operational Notices. If interruptions are deemed necessary, Operational Notices

are posted daily with a 5-day forecast. Notification of pipeline cuts and mismatches over weekends and holidays follow NAESB cycles of Timely, Evening, Intra-Day 1 and Intra-Day 2. Pipeline scheduled quantities are compared to quantities nominated on the Energy Management Website by all NGSs for each NAESB cycle. If contracts are identified to have mismatched quantities, NGSs are emailed, and a posting is made to the Energy Management Website until such time that the issue has been resolved.

Q. Mr. Reyes claims that UGI did not meet its obligation to provide notifications of cuts and interruptions on weekends and holidays for the months of December and January. How do you respond?

A. With respect to notifications of pipeline cuts, I do not agree with the claims of Mr. Reyes. Mr. Reyes provides no evidence to support these claims. UGI Gas is fully compliant with terms to provide notifications of cuts on weekends and holidays as outlined in Paragraph 91 of the Settlement at Docket Nos. R-2024-3052716, et al., which stated:

> 89. Interruption Notification. UGI Gas will provide direct notification of interruptions to customers and their licensed natural gas suppliers ("NGSs") in parallel, inclusive of notice of permitted volumes, if any. UGI Gas will use commercially reasonable efforts to provide direct notification to customers and NGSs as close together as circumstances allow, recognizing emergency situations may impact this notice unpredictably.
>
> …
>
> 91. Weekend/Holiday Cuts/Mismatches. Within 6 months of the issuance of a final order in this proceeding, UGI Gas will implement a "manual or non-permanent" solution to notify NGSs when UGI Gas identifies nomination cuts/mismatches over weekends and holidays via posting to the Energy Management Website, which will trigger email distribution to all NGSs for the NAESB cycles of Timely, Evening, Intra-Day 1 and Intra-Day 2. This email distribution will identify the contracts affected by the subject nomination cuts/mismatches. The Company will utilize commercially reasonable efforts to maintain this manual process for the specified times. UGI Gas will continue to review and evaluate permanent or automated

solutions for such notifications and will continue to operate under this manual process until a permanent solution is implemented.

On the matter of customer interruption notifications, UGI Gas recognized an error in the manual process used to notify NGSs of customer-specific interruptions in January 2026 and promptly corrected this issue. Since that time UGI Gas remains compliant with Paragraph 89 above.

Q. Mr. Reyes recommends that the Commission monitor UGI Gas's compliance with the settlement requirement that it provide notification of cuts and interruptions on NGSs on weekends and holidays in the same manner it does for weekdays. What is your response to this recommendation?

A. I do not agree with the recommendation of Mr. Reyes. UGI Gas has addressed the timely notification of both pipeline cuts and customer interruptions to NGSs, and remains compliant with terms to provide notifications of interruptions and cuts on weekends and holidays as outlined in Paragraph 89 and Paragraph 91 of the Settlement at Docket Nos. R-2024-3052716, *et al*. His request should be rejected.

B. DAILY IMBALANCE TRADING AND PENALTIES

Q. What happens if a supplier is not within their required delivery tolerance?

A. After final usage and supply deliveries are determined, identification of any NGS exceedance of their daily delivery tolerance occurs. At such point, penalties are assessed in accordance with the level of restriction (i.e., Critical Day, OFO, etc.) in effect on the gas day.

Q. Why is it necessary for UGI Gas to issue penalties for noncompliance?

A. UGI Gas has a statuary obligation under the Public Utility Code, 66 Pa.C.S. §§ 1501, 1318, to provide safe, reliable, and least cost natural gas service to its customers. UGI Gas issues penalties as a deterrent for under or over deliveries to the distribution system that could potentially cause financial harm or physical disruptions of natural gas service to UGI Gas customers. Suppliers that do not match deliveries with expected customer usage create additional operational challenges for UGI Gas to balance overall positions with interconnecting interstate pipelines and may cause UGI Gas to incur penalties from interstate pipelines. In addition, NGSs that fail to deliver the supply necessary to serve their customers during peak winter events create the risk of a supply shortfall that, without utility intervention, could impact the ability to serve all customers.

Q. What concerns does Mr. Reyes raise with regard to imbalances and penalties?

A. Mr. Reyes indicates that imbalances are the number one reason penalties are imposed, and notes suppliers should be provided with the opportunity to engage in imbalance trading to ensure system balance and minimize penalties.

Q. What is daily imbalance trading?

A. Daily imbalance trading allows NGS's to "trade" an imbalance position with another NGS if their imbalance position is in the opposite direction, in essence netting the imbalance between both parties.

Q. Does UGI offer daily imbalance trading?

A. No. The Company does not offer daily imbalance trading.

Q. Mr. Reyes claims that other utilities allow imbalance trading and that UGI Gas should also be required to implement daily imbalance trading. Do you agree?

A. No, I do not. UGI Gas operates its distribution system independently of other utility companies, with its own unique and complex mix of pipeline interconnects, supply contracts, and limitations on system flexibility. Specifically, UGI Gas has a geographically large and disconnected system, where a shortfall or long position in one region or system would not operationally, or contractually, offset the opposite position in another region or system within the service territory to achieve a net zero impact to UGI Gas.

Q. Mr. Reyes claims that if UGI Gas were to implement daily imbalance trading, it would result in lower costs to customers on the system while having no impact to physical operations. Is this an accurate assumption?

A. No, it is not. It is prudent for UGI Gas to deter any supplier behavior that could result in daily fluctuations between supply and demand, as even minor deliveries beyond daily tolerances could result in additional costs for customers. In addition, the UGI Gas (EMW) is not configured for daily imbalance trading, as nearly all billing and reconciliation functions operate at the monthly aggregated level. System and programming modifications for daily imbalance trading would result in significant costs for UGI Gas customers.

Q. Mr. Reyes claims that the Company's imbalance penalties are disproportionate because there is no proof of supplier arbitrage. What is your response?

A. UGI Gas does not need proof of past supplier arbitrage in order to prevent future occurrences. Suppliers can take advantage of low penalties to achieve flexibility with obtaining/diverting gas supply and transportation capacity to maximize profits (or minimize penalty exposure) based on differences in the spot market price of gas across locational delivery areas. Even in situations where a supplier is not "short" supply, but market conditions create large profit opportunities, finding a way to maximize profits by overrunning contract entitlements, redirecting supplies or making affirmative decisions to incur a lower cost penalty can all be means by which resulting supply shortfalls can impact UGI Gas.

Moreover, arbitrage may involve situations where UGI Gas, as the supplier of last resort ("SOLR"), must then replace the diverted gas supplies and potentially have to engage in a bidding war to divert other supplies or even the same supplies back to its own system, further perpetuating the impacts of arbitrage. Moreover, UGI Gas's system has distinct characteristics that also necessitate strong penalties to ensure reliability and safeguard against arbitrage:

1. UGI Gas serves many customers in geographically diverse and often rural areas, with portions of the system that have limited supply options and redundancy;
2. The Company has experienced significant challenges during past extreme weather events, where supply shortfalls can have serious consequences for system reliability and customer safety;
3. UGI Gas has more dispersed gate stations and a more complex supply portfolio than many other Pennsylvania NGDCs, which increases the operational challenges associated with supply imbalances.

4. As SOLR, UGI Gas has a regulatory mandate to ensure that its system integrity is protected against arbitrage scenarios.

These factors justify UGI Gas's penalty structure, which proactively seeks to deter activities that threaten reliable and affordable service, as just and reasonable.

Q. Mr. Reyes recommends that UGI Gas be required to submit a new tariff with penalties at rates no higher than 20% more than the average penalties of all Pennsylvania natural gas distribution companies. Do you agree with this recommendation?

A. No, I do not agree with this recommendation for the above-stated reasons. Additionally, there is no "one-size-fits-all" approach to penalty structures that would be appropriate for all NGDCs in Pennsylvania. Each utility's penalty structure should reflect the specific characteristics of its system, the surrounding utility systems, the relevant supply sources within the market area, and the particular challenges for maintaining reliability. The Company's focus is on prevention rather than on assessing penalties and/or damages after a failure to deliver has occurred, potentially with disastrous consequences to life and property. UGI Gas's penalty structure provides clear incentives for suppliers to take all reasonable measures to meet their obligations and support continuous reliability.

C. FORCE MAJEURE

Q. Does UGI Gas currently have a documented policy regarding force majeure for its suppliers?

A. No, UGI Gas does not currently have a documented policy regarding force majeure for its suppliers, and reviews supplier force majeure claims on a case-by-case basis.

Q. What are UGI Gas's concerns with the evaluation and resolution of supplier force majeure claims?

A. For UGI Gas to consider a force majeure claim, suppliers would need to provide timely evidence of upstream force majeure, and documentation of all reasonable actions taken by the supplier to maintain deliveries of gas supply to UGI Gas. Additionally, UGI Gas may incur penalties, or deploy additional assets to avoid penalties, often at additional expense, to address shortfalls associated with upstream force majeure events.

Q. What is UGI Gas's experience with suppliers claiming force majeure?

A. In the past, suppliers have typically emailed UGI Gas to notify of their non-delivery because of claimed force majeure, often with little detail and well after the shortfall occurred, and without evidence of efforts to arrange for the timely delivery of alternate supply. This leaves UGI Gas with little information, notice, or ability to balance for non-deliveries. Additionally, outside of exceptional events such as winter storm Elliott, UGI Gas rarely receives force majeure claims, with many years of zero requests received.

Q. Mr. Reyes recommends that UGI Gas be required to implement a tariffed policy that provides for force majeure protections. Is his recommendation necessary?

A. No it is not. As stated above, UGI Gas must provide safe and reliable natural gas service to customers, even where a supplier fails to deliver on the claimed basis of a force majeure

event. For this reason, it is important for UGI Gas to protect the interest of its customers and to limit the circumstances where UGI Gas accepts a supplier's failure to deliver.

D. STANDARDS OF CONDUCT

Q. Does UGI Gas require all employees to follow the Standards of Conduct?

A. Yes. UGI Gas expects all of its employees to follow the Standards of Conduct, and provides annual training to its employees on the Standards of Conduct to support a culture of compliance. This training is mandatory for employees that may engage with suppliers, undertake market activities, or have access to competitively sensitive data. UGI Gas monitors employee participation in this training to ensure that all such Company employees are trained on the Standards of Conduct.

Q. Mr. Reyes recommends that the Commission review UGI Gas's compliance with the Standards of Conduct as it relates to affiliated natural gas suppliers as part of its next audit. Do you wish to comment on this recommendation?

A. UGI Gas is currently undergoing a Commission Management Efficiency Audit, which includes a review of Affiliated Interests and Cost Allocations. While the results of this audit are expected later this year, the Commission follow-up performed in a 2023 Management Efficiency Investigation did not indicate any Affiliate Code of Conduct concerns. Therefore, Mr. Reyes' recommendation is unnecessary because the Commission can, and already does, review UGI Gas's compliance with the Standards of Conduct and will recommend corrective action to the extent any issue is identified.

Q. Mr. Reyes recommends that the Commission direct UGI Gas to periodically conduct an internal audit that is designed to review compliance with the Standards of Conduct and report the results to the Commission's Office of Competitive Market Oversight ("OCMO"). Do you agree?

A. No. The Commission already reviews affiliate interactions in its periodic management efficiency audits and investigations. Further, Mr. Reyes does not make any specific, fact-based allegations in his testimony that relate to the Standards of Conduct. He only offers speculation. UGI Gas is fully compliant with the Standards of Conduct and is already subject to the Commission's oversight for Standards of Conduct compliance (e.g., Bureau of Audits, Office of Competitive Market Oversight ("OCMO") and Office of Administrative Law Judge). As previously mentioned, UGI Gas leadership supports a culture of compliance through the required annual training process for those employees that may engage with suppliers, undertake market activities, or have access to competitively sensitive data. There is simply no action required by the Commission as a result of Mr. Reyes's testimony. Moreover, no supplier, customer, or Commission department has raised any allegations against UGI Gas through the Commission's dispute resolution process set forth in 62 Pa. Code § 62.142(b).

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit TJA-1

TIMOTHY J. ANGSTADT

UGI UTILITIES, INC.
VICE PRESIDENT – ENERGY SUPPLY & MEASUREMENT

Summary

Energy Supply, Engineering, and Operations executive with over 26 years of broad experience in natural gas transmission and distribution activities, including operations and maintenance, engineering, regulatory compliance, capital budgeting and construction, project management, technology implementation, energy procurement and portfolio management, and business process transformation.

As Vice President – Energy Supply & Measurement:

- Leads a multi-functional team responsible for the procurement and portfolio management of approximately $500 million in natural gas and electricity supplies annually.
- Leads measurement, telemetry, revenue protection, and claims activities associated with the operation of over 12,000 miles of natural gas transmission and distribution pipelines and related assets, serving over 700,000 customers in Pennsylvania and Maryland.

Prior Positions with UGI Utilities, Inc.

Vice President – Energy Supply & Measurement (Denver, Pa.)	August 2023 – Present
Vice President – Operations (Denver, Pa.)	February 2019 – August 2023
Program Director – UNITE (UGI's Next Info. Technology Enterprise) (Reading, Pa.)	February 2016 – February 2019
Director – Operations, South Region (Reading, Pa.)	June 2012 – February 2016
Operations Manager – West Region (Harrisburg/Middletown, Pa.)	July 2008 – June 2012
Manager – Operational Support (Reading, Pa.)	December 2007 – July 2008
Manager – UGI/Penn Natural Gas Integration (Wilkes-Barre/Reading, Pa.)	November 2006 – December 2007
Engineer – Customer Service and Performance Systems (Reading, Pa.)	June 2005 – November 2006
Operations/Construction and Maintenance Superintendent (Reading, Pa.)	September 2003 – June 2005
Engineer II – Gas Utility Headquarters (Reading, Pa.)	January 2003 – September 2003
Engineer I/II – Reading Area (Reading, Pa.)	January 2000-January 2003
Engineering Assistant – Reading Area (Reading, Pa.)	June 1999 – August 1999

Education

MiF, The Pennsylvania State University, Malvern, Pa.
MBA, The Pennsylvania State University, Malvern, Pa.
BS, Mechanical Engineering, The Pennsylvania State University, State College, Pa.

Prior testimony provided to the Pennsylvania Public Utility Commission:

Docket No. R-2021-3030218	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding
Docket No. R-2019-3015162	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 15-R

Rebuttal Testimony of
Jessica R. Rogers

Topics Addressed:

Overview of Rebuttal
Affordability Concerns
Ratemaking and Policy Considerations
Purchase of Receivables
Public Input Hearing Testimony

Dated: May 13, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jessica R. Rogers. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI") as its Vice President, Rates and Regulatory Affairs. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President, Rates and Regulatory Affairs, I am responsible for all rate and regulatory filings for UGI Gas and UGI Electric before the Pennsylvania Public Utility Commission, the Maryland Public Service Commission, and the Federal Energy Regulatory Commission.

Q. What is your educational and professional background?

A. Please see my resume, UGI Gas Exhibit JRR-1R, which is attached to my testimony.

Q. Have you testified previously before any public utility commission?

A. Yes. UGI Gas Exhibit JRR-1R contains a list of those proceedings.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Gas?

A. No, I did not.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony has five primary purposes. First, I explain that I will be addressing certain topics originally addressed by UGI Gas Witness Mr. Hans G. Bell in his direct testimony (UGI Gas Statement No. 1). While I am not adopting his direct testimony or any of his discovery responses as my own, I will be taking over as the Company's witness for the topics identified from this stage forward. Second, I provide an overview of the Company's rebuttal case in this proceeding. Third, my testimony responds to certain portions of the following direct testimony submitted by the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), and the Coalition for Affordable Utility Service and Energy Efficiency in Pennsylvania ("CAUSE-PA") related to affordability and ratemaking policy issues. Specifically, I provide rebuttal testimony in response to: OCA Witnesses Michael Deupree (OCA St. 1), Barbara R. Alexander (OCA St. No. 5), and Zachary Teti (OCA St. 7 and 7S); OSBA Witness Mark D. Ewen (OSBA St. No. 1); and CAUSE-PA Witness Patrick Cicero (CAUSE-PA St. No. 1). Fourth, I respond to certain testimony offered by OCA and CAUSE-PA related to the Company's purchase of receivables program. Finally, I address certain public input hearing testimony.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. In addition to UGI Gas Exhibit JRR-1R, which is a copy of my resume, I am also sponsoring UGI Gas Exhibits JRR-2R through JRR-4R, as described later in my testimony.

Q. Do you have any further introductory comments?

A. Yes. While I am a licensed attorney in Pennsylvania, having practiced in Pennsylvania and before this Commission for more than a decade as an attorney representing public utilities, my testimony is not intended to offer legal opinions or conclusions. Rather, my testimony will respond to the policy concerns, and associated topics raised by the other parties' witnesses.

II. ROLE IN THE CASE

Q. Have you had an opportunity to review UGI Gas Statement No. 1, the direct testimony of Hans G. Bell, as well as Mr. Bell's discovery responses?

A. Yes, I have.

Q. Please explain your role in this proceeding in light of Mr. Bell's testimony and responses to discovery.

A. Mr. Bell should continue to be understood as the witness responsible for UGI Gas Statement No. 1 and all responses to discovery where he is indicated as the sponsor up to this point. However, with the submission of my rebuttal testimony, I will assume the role of UGI Gas's overview witness.

III. OVERVIEW OF THE COMPANY'S REBUTTAL CASE

Q. Please introduce the Company witnesses that will be providing rebuttal testimony in this matter, and provide a brief description of the subject matter of their rebuttal testimony.

A. The Company's rebuttal testimony is comprised of 14 witnesses, including many of the witnesses that submitted direct testimony as well as certain new witnesses that are offering rebuttal testimony to respond to specific issues raised by other parties in this proceeding. In addition to myself, the Company's rebuttal witnesses are:

- **Tracy A. Hazenstab** (UGI Gas Statement No. 2-R) updates several Operation and Maintenance ("O&M") adjustments and revenue components of UGI Gas's initial filing that required updating, but rebuts the PUC's Bureau of Investigation and Enforcement ("I&E") and OCA's adjustments to the Company's revenue requirement, to rate case expense, energy efficiency and conservation expense, cash working capital, and income tax expense (for interest synchronization).

- **Jill E. Walter** (UGI Gas Statement No. 3-R) responds to testimony regarding pipeline replacement costs, the Company's methane detection pilot, training protocols, and responds to certain claims regarding testimony at the public input hearing.

- **Vivian K. Ressler** (UGI Gas Statement No. 4-R) accepts the vacancy rate proposed by I&E and OCA, rebuts I&E's proposed adjustments to the Company's incentive compensation claim, I&E and OCA's reduction to employee activity expense, I&E's adjustment to membership due expenses, and OCA's adjustment to the PUC Assessment charge.

- **Amy M. Keller** (UGI Gas Statement No. 5-R) corrects an error regarding inclusion of the amortization of the regulatory liability for the past over-recovery of post-retirement welfare plan expense. She rebuts OCA's adjustments to accumulated depreciation and Accumulated Deferred Income Tax and I&E's recommendations regarding PUC annual report data.

- **John F. Wiedmayer** (UGI Gas Statement No. 6-R) responds to the parties' testimony regarding depreciation.

- **Vicky A. Schappell** (UGI Gas Statement No. 7-R) accepts I&E's reporting requirements related to plant in service for the Future Test Year ("FTY") and Fully Projected Future Test Year ("FPFTY").

- **Dylan W. D'Ascendis** (UGI Gas Statement No. 8-R) responds to the parties' testimony regarding capital structure and return on equity ("ROE"), and overall rate of return.

- **Sherry A. Epler** (UGI Gas Statement No. 10-R) accepts I&E's position regarding test year sales and revenues, as well as CAUSE-PA's proposal to make certain tariff corrections. She rebuts the Retail Energy Supply Association's ("RESA") testimony regarding Rate NNS.

- **John D. Taylor** (UGI Gas Statement No. 11-R) rebuts testimony from the other parties' regarding the Company's proposed revenue apportionment, the Allocated Cost of Service Study, customer charges, and the weather normalization adjustment ("WNA").

- **Brian J. Meilinger** (UGI Gas Statement No. 12-R) rebuts the testimony of OCA and CAUSE-PA related to affordability and the impact of the rate increase on low-income customers as well as identification and screening of low-income customers, compliance with the 2025 Gas Rate Case Settlement ("Settlement"), and these parties' testimony regarding the Company's Universal Service Programs.

- **Daniel V. Adamo** (UGI Gas Statement No. 13-R) rebuts the testimony of OCA, CAUSE-PA, and the OSBA related to compliance with the Settlement, customer service issues, and the Company's credit and collection expenses.

- **Timothy J. Angstadt** (UGI Gas Statement No. 14-R) rebuts certain of the RESA testimony and issues raised therein.

- **Cyndee Fang** (UGI Gas Statement No. 16-R) rebuts the other parties' testimony on general macroeconomic concerns around affordability.

Q. Based on your review of the testimony submitted in this proceeding, what are the major issues in this case?

A. The major issues in this case are: (1) overall revenue requirement, including limited adjustments to the Company's claimed O&M expenses; (2) cost of common equity and capital structure; (3) depreciation methodology; (4) cost allocation; (5) rate design, including the Company's proposal to continue its WNA Pilot in a modified form; and (6) affordability concerns. While these are not exhaustive of the issues raised, these are the

most impactful from a revenue and affordability perspective. As explained below and in more detail in the Company's rebuttal testimony, the Commission should adopt the Company's position on each of these issues and reject the unsound and unsupported proposals set forth in the other parties' direct testimony. As identified in the summary above, the Company has made adjustments in its rebuttal case to align with the positions taken by other parties where it was reasonable and appropriate to do so.

Q. Is the Company revising its initially requested revenue requirement?

A. Yes. UGI Gas initially requested a $99.368 million increase in annual operating revenues. However, the Company's most recent data and updates within rebuttal, including the voluntary adoption of certain adjustments proposed by other parties, now justifies an increase of $98.693 million.

Q. Please summarize the other parties' positions on the Company's overall revenue requirement, and the Company's rebuttal testimony on this issue.

A. The other parties' positions can be captured in two categories: adjustments proposed based on a detailed analysis of the Company's cost of service using the Commission's standard approach to ratemaking, and general proposals that are not grounded in cost of service principles. Specifically, I&E and OCA both undertake a cost-of-service analysis to produce recommended revenue requirements and to identify adjustments to certain expenses. I&E St. No. 1, at pp. 4-5; OCA St. 1, at pp. 39-54. However, OCA and CAUSE-PA, as primary positions, recommend that no rate increase should be allowed in light of macroeconomic circumstances and general affordability concerns. OCA St. 1, at pp. 3-4;

CAUSE-PA St. No. 1, at pp. 5-6. Similarly, OSBA provides no detailed revenue analysis or specific disallowances/adjustments, but makes general comments, encouraging the Commission to "carefully consider ratepayers' interest, affordability concerns, and the risk reduction benefits of a low-risk regulatory environment" in making its determination in this proceeding. OSBA St. No. 1, at p. 2.

To the extent the other parties provided a detailed analysis and specific adjustments, appropriate witnesses for the Company respond to the merits and facts regarding such adjustments. However, OCA and CAUSE-PA advance proposals that encourage the Commission to supplant its detailed analytic process for evaluating the need for and level of various costs incurred to serve customers with a generic rejection of the proposed rate increase based on macroeconomic conditions. The Commission should reject these arguments as they are contrary to long-standing Commission precedent and the Commission's required detailed analytic process, and reflect bad policy that may cause long-term harm to consumers, as described later in my testimony.

Q. Are the revenue requirement amounts proposed by I&E and OCA reasonable?

A. No. I&E's and OCA's proposals simply do not reflect the facts or sound application of fundamental ratemaking principles. Further, the specific revenue requirements offered by I&E and OCA would hinder the Company's ability to continue modernizing its system in order to provide safe and reliable service to customers. OCA's proposed revenue decrease, in particular, could substantially undermine the ability of UGI Gas to continue its accelerated pipe replacement program at its current pace, halt the Company's ability to make incremental progress on customer service quality and key programs to assist low-

income customers, and could cause a downgrade and financial market impacts that would increase the cost of capital.

This case is driven by capital investments. UGI Gas will invest approximately $468 million during the FPFTY in infrastructure and business systems to ensure that its service is safe, reliable, and customer-focused. The positions offered by I&E and OCA would frustrate the sustained pace of safety investments identified by the Company at a reasonable cost – investments that no party has disputed are necessary or proper for safely and reliably serving customers. Furthermore, the investments made possible by the rate increase reflected in this case will sustain thousands of good paying jobs and provide many other positive economic impacts directly to the communities where UGI Gas operates.

Q. How did the parties reach their lower revenue requirement recommendations?

A. There are very few areas of dispute in this case, and the vast majority of the difference in the revenue requirements are found in four primary areas: (1) unreasonable adjustments to the return on equity; (2) unprecedented use of a hypothetical capital structure where the Company's proposed capital structure is within the range presented by the proxy group; (3) depreciation adjustments that have been repeatedly rejected by the Commission; and (4) improper adjustments to projected operating expenses. Many of the witnesses' recommendations are founded on significant deviations from the standard ratemaking principles historically applied by the Commission, as described later in my testimony. All of the I&E and OCA recommendations that the Company has not accepted are fully addressed by the Company's witnesses in their rebuttal testimony.

Other parties' (I&E, OCA, and OSBA) equity return proposals are misaligned with the Commission's calculation of market based equity returns of the natural gas barometer group included in the Commission's recently published Quarterly Earnings Report for Q3 of 2025.[1] Moreover, the extensive evidence of risk characteristics of UGI Gas detailed by UGI Gas witness Dylan D'Ascendis fully supports the Company's 10.75% cost of equity claim.

Q. Why is it important for UGI Gas to earn a reasonable rate of return?

A. As I noted previously, this case is overwhelmingly about the Company's plans to invest in infrastructure work that will allow it to safely and reliably serve its customers, increase the number of Pennsylvanians who have access to natural gas service, and provide its customers with a quality customer service experience. Cost-effectively making these investments requires substantial and sustained access to capital. As explained in the rebuttal testimony of UGI Gas Witness D'Ascendis, the return on equity proposals advanced by the other parties are insufficient. First, as noted by Witness D'Ascendis, both OCA and CAUSE-PA argue that no increase should be approved, which based on the Company's planned costs reflected in this case would produce an effective return of 7.70% - well below the Commission's published Quarterly Earnings Report. Further, OCA's proposed return on equity, in particular, would be lower than any return authorized by the Commission in the last four decades. Further, OCA and CAUSE-PA both advance capital structure proposals that do not align with the long-standing Commission practice of using

[1] *Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2025*, Docket No. M-2025-3059329, https://www.puc.pa.gov/pcdocs/1922794.pdf (last visited May 12, 2026),

the Company's actual capital structure. The Company must be able to attract capital at a reasonable cost in order to undertake the investments necessary to provide safe and reliable service. These positions advanced by OCA and CAUSE-PA could frustrate the Company's ability to do so.

Q. What is the Company's overall position regarding the direct testimony of the other parties in this matter, and the Company's proposed base rate increase?

A. The Company's rebuttal testimony summarized above responds to each of the individual issues raised by the opposing parties, as well as the places where the Company has aligned its case to either accept or not oppose certain positions. However, for the most part, UGI Gas does not accept the other parties' adjustments, for the reasons identified in the Company's rebuttal testimony.

UGI Gas asks the Commission to evaluate its case based on the traditional ratemaking principles it has developed over decades of experience. Importantly, no party has challenged any of the Company's planned capital investments reflected in this proceeding. Stated differently, not a single dollar of the $468 million identified for essential and important infrastructure investments projected to be made during the FPFTY was challenged on the basis that it is unnecessary, unjustified, unreasonable, or would not be used to serve the public. The magnitude of these important capital investments, alone, clearly indicates that rate relief is necessary. The Commission should approve the requested increase with the modifications and conditions reflected in the Company's rebuttal position, and authorize a rate increase of $98.693 million.

IV. AFFORDABILITY AND RATEMAKING

A. REBUTTAL TO AFFORDABILITY CONCERNS

Q. Witnesses for OCA[2] and CAUSE-PA[3], and various Public Input Hearing witnesses[4] presented testimony regarding affordability concerns, both with respect to broader economic trends, utility bills generally, and UGI Gas's proposed rate increase specifically. Please respond.

A. The Company recognizes and understands the need to balance the completion of the important work it undertakes in order to provide safe and reliable service by continuing to make sound investments to improve its distribution system on the one hand, and providing that safe and reliable service at affordable rates on the other hand. The Company's focus on affordability is shown in how it operates and in the choices it affirmatively made in this case. As I and other witnesses will address in detail in rebuttal testimony:

- UGI Gas has managed its operating costs effectively over time such that these costs have increased at a pace lower than general inflation during the same period;
- This winter, the Company's use of WNA returned more than $27 million to customers in the form of bill credits;
- The Company has proposed to continue modifications to its WNA that will exclude low-income customers on the Company's Customer Assistance Program ("CAP"), and has made adjustments in this proceeding that are expected to make its operation more balanced over time;
- UGI Gas is seeking a return on equity in this proceeding that is below the mid-point of its peer group;
- The Company is not seeking a management effectiveness adjustment to its ROE in this case, despite providing evidence regarding the effectiveness of its management in its execution of safety related projects including achieving the removal of all known cast iron pipe, strong customer service performance, and the effective management of operating costs. Based on proposals in past cases for an incremental adjustment for

[2] *See* OCA St. 1, at pp. 10-20; OCA St. 5, at pp. 8-9; OCA St. 6, at pp. 5-41; and OCA St. 7, at pp. 4-9.
[3] *See* CAUSE-PA St. No. 1, at pp. 15-34.
[4] *See* Tr.118, 120-121, 128, 158.

management effectiveness, not including this adjustment reduced the Company's claim by more than $6 million;

- Over the past five years, UGI Gas has donated more than $4.35 million to Operation Share to support payment troubled customers, and has indicated in testimony in this proceeding that it will increase its annual donation up to $1 million for the next three years;

- The Company has proposed to expand the application of the Universal Service Plan ("USP") Rider to provide UGI Gas with the ability to negotiate contracts that include a contribution by Rate XD customers that would lower the cost of the USP Rider to residential customers while obtaining contributions from UGI Gas's largest industrial customers;

- The Company continues to evolve and expand programs targeted at supporting energy efficiency and affordability. In FY2025, UGI Gas's total support provided to payment troubled customers across its programs was approximately $31.9 million, excluding Operation Share;

These are the activities reflected in, and central to, this case. The revenue reflected in this case supports 1,528 UGI Gas jobs, as well as additional jobs at UGI Corporation, headquartered in King of Prussia that support service to UGI Gas's ratepayers. The capital investment program also supports up to approximately 500 additional contractor jobs, many of those being union jobs. In 2025 alone, the Company invested over $320 million in Pennsylvania infrastructure, the overwhelming majority of which was spent with in-state vendors and contractors.

Further, UGI undertakes a substantial amount of activity to benefit local communities that is not rate recoverable. Since October 1, 2021, UGI has donated more than $7,000,000 from non-ratepayer funds, as well as thousands of hours of volunteer time and hundreds of thousands of dollars in individual employee donations organized through Company-run campaigns, to serve and support organizations located in the communities it operates in. These donations are in addition to the Corporate donations to Operation Share, which over the same period totaled over $4,000,000. In short, the revenue generated by

customer rates established in this proceeding is overwhelmingly being reinvested into Pennsylvania both directly and indirectly.

Q. Please respond to OCA Witness Deupree's general recommendations regarding the actions that OCA believes the Commission should take in this matter. OCA St. 1, at pp. 3-7.

A. Witness Deupree encourages the Commission to take an approach that would evaluate utility rate relief entirely on the macroeconomic circumstances at the time rate relief is requested, rather than on the operating circumstances that are traditionally used to determine whether (1) costs are necessary or appropriate for service to the public and prudently incurred, and (2) the overall rates and rate design are just and reasonable. Essentially, Witness Deupree asks the Commission to depart from its statutory requirements, its precedent, and the fundamental concept of cost-of-service ratemaking. His approach, if adopted, would require a complete departure from more than a century of utility ratemaking in Pennsylvania.

Q. Do any other witnesses take positions similar to Witness Deupree?

A. Yes. CAUSE-PA Witness Cicero takes positions similar to the one advanced by Witness Deupree. Mr. Cicero proposes that no rate increase be granted in this proceeding, pointing to general economic concerns, affordability challenges for low income customers, and his general disagreement with the Commission's methodology and precedent. CAUSE-PA St. No. 1, at pp. 5-6. Mr. Cicero conducts no analysis of the Company's cost of service for the FPFTY before he concludes that the Commission should reject the rate increase as a

whole. CAUSE-PA St. No. 1, at pp. 5-6, 47-48. Indeed, he makes clear he offers no cost of service based recommendation when he indicates he does not have a recommendation about the amount of a rate increase should the PUC reject his proposal to deny any rate increase. CAUSE-PA St. No. 1, at p. 42.

Q. Both OCA and CAUSE-PA advance positions focused on the current macroeconomic situation, and the regulatory compact and zone of reasonableness principles. OCA St. 1, at pp. 7-9; CAUSE-PA St. No. 1, pp. 8-14. Are there any flaws with these arguments?

A. Yes. There are a number of issues with Witness Deupree's testimony. First, as previously noted, Witness Deupree's testimony fails to conform to statutory and regulatory requirements that have been acknowledged by the Commission over more than a century of rate cases. Critically, Witness Deupree cites to no instance where the Commission rejected cost of service ratemaking in favor of an evaluation of macroeconomic circumstances. As recently as 2020, during the COVID-19 shutdown – which resulted from a global pandemic – the Commission relied upon cost of service ratemaking to ensure that utilities maintained safe and reliable service to the public. Witness Deupree points to the conflict in the Persian Gulf to support his approach, OCA St. 1, at p. 4, yet there have been past conflicts (including in the Persian Gulf) and these did not cause the Commission to reject cost of service ratemaking.

Both Witness Deupree and Witness Cicero speak to the regulatory compact as establishing the bedrock principle that in exchange for monopoly authority, a utility submits to rate and service regulation where the Commission must permit the utility to

recover its costs plus a reasonable opportunity to earn a return on its investment. Witness Deupree also speaks to the zone of reasonableness in his testimony. But ultimately both Witness Deupree and Witness Cicero ignore the very processes used to ensure that rates are reasonable and not confiscatory, and instead both support no increase as their primary position. Witness Deupree also supports a secondary position of a rate decrease. These positions are very clearly unreasonable and confiscatory. This is particularly true given that neither Witness. Cicero nor any OCA witness opposes the ongoing work or the vast majority of the costs reflected in the Company's filing. In fact, OCA's revenue position relies primarily upon an unreasonably low ROE, a hypothetical capital structure, and a modified approach to depreciation – all of which are unprecedented in Pennsylvania utility history. Adopting any one of these proposals alone would be unprecedented and have wide-ranging and adverse consequences for UGI Gas and its ability to continue improving safe and reliable service. Witness Cicero similarly proposes a hypothetical capital structure that is not consistent with Commission precedent.

Q. Are there any contradictions in the positions Witness Deupree takes?

A. Yes. In my experience and based on my review and understanding of testimony in other base rate proceedings, OCA has long-opposed the use of general inflationary factors or other generic economic data as a basis for supporting the increase to any portion of the Company's individual cost claims. Yet, Witness Deupree now looks at general economic conditions, and specifically the impact of universal cost increases (i.e., general inflationary pressures) on what he presumes to be indicative of customer affordability. It would be both unreasonable and unfair to disallow general-inflation-based adjustments to aspects of

the cost of service for the utility, but to allow general-inflation-based concerns unrelated to the cost of service to be the basis upon which a rate increase is denied or reduced. And while I certainly do not dispute that inflationary impacts are affecting customers, those inflationary impacts are not "historic" or unusual compared to those previously seen by this Commission.

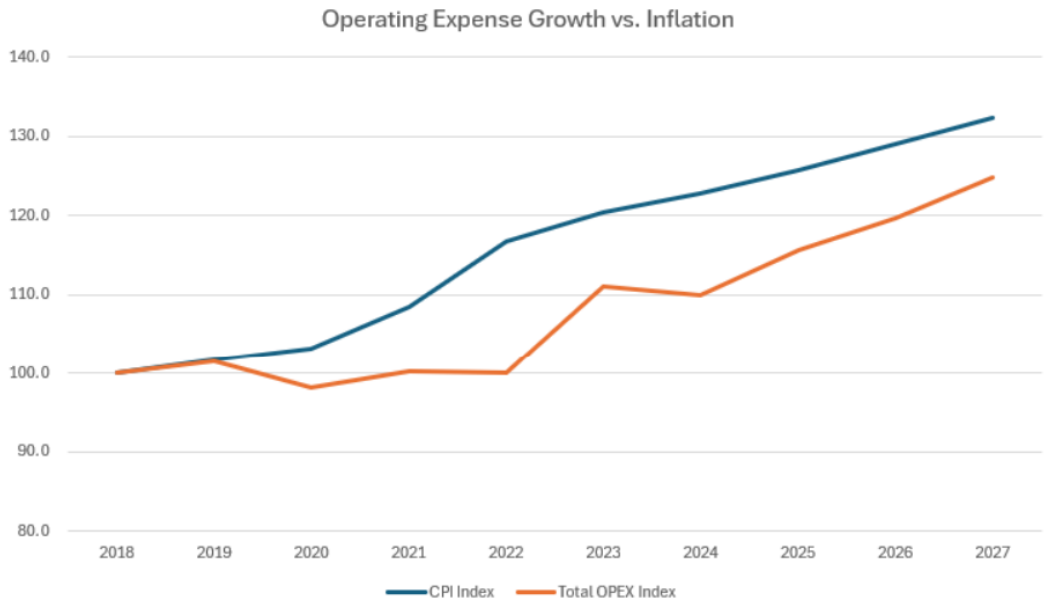
Q. Witness Deupree testifies that "utility rates do not occur in a vacuum." OCA St. 1, at p. 10. Please respond.

A. I agree with Witness Deupree that utility rates do not occur in a vacuum. In fact, utilities do not operate in a vacuum, either. To the extent Witness Deupree believes that customers are experiencing inflationary pressures that are increasing their costs, this is true for the utility, as well. The Company has continued to see increasing costs for its operations. While UGI Gas has worked hard to keep its operating costs down—including performance in managing those costs that beats general inflation during the same period—disallowing any increase at this time is not reasonable given the critical nature of the services this rate increase will fund. UGI Gas Witness Fang testifies at length as to the appropriate societal weighing of non-utility affordability issues in UGI Gas St. No. 16-R, but Witness Deupree provides no basis, methodology, or precedent for how the Commission might weigh generic cost of living concerns with the data provided by UGI Gas on its actual and anticipated cost of providing service to customers in the FPFTY.

Q. What evidence supports the claim that the Company has effectively managed its costs at a pace lower than inflation?

A. Included with my testimony as UGI Gas Exhibit JRR-2R is a breakdown of key operating and maintenance cost categories for UGI Gas, as well as its total operating and maintenance expenses for each year from 2018 through the FPFTY reflected in this case, mapped against inflation. A graphical representation of this information is reflected in Table 1, below:

Table 1: UGI Gas Operating Costs from 2018 through FPFTY v. CPI



As shown above, and in greater detail in UGI Gas Exhibit JRR-2R, based on the Company's actual and projected operating costs – none of which are developed using general inflationary factors – UGI Gas has effectively managed its operating costs such that they have increased at a pace lower than inflation. Despite being subject to general inflationary pressures, UGI Gas has taken active steps to manage how those pressures impact its cost of service, and has minimized the level of O&M expenses reflected in its cost of service in a manner that has protected and benefited its customers.

Q. Is OCA Witness Deupree's attempt to focus on wholesale electricity prices and wholesale natural gas prices appropriate or helpful in this proceeding? OCA St. 1, at p. 14-15.

A. No. This case is exclusively about the cost to UGI Gas of providing distribution service to its customers that meets its obligations under 66 Pa.C.S. Section 1501. Commodity prices are not included in the Company's distribution cost of service, and are not a part of this proceeding.

Q. What about his focus on the Iranian conflict, its alleged impact on global oil prices, and purported impacts on LNG and wholesale natural gas costs? OCA St. 1, at pp. 15-18.

A. Witness Deupree's testimony regarding the current Persian Gulf conflict and the potential for associated cost impacts is not germane to the question of whether the costs reflected in the Company's case are necessary or prudently incurred in order to provide natural gas distribution service to its customers. As I noted previously, this is not the first time the Commission has addressed a base rate case during a war, conflict, or other military engagement abroad, or other disruptive global event, and such activities have never been identified by this Commission as the basis for a full departure from cost of service ratemaking as OCA Witness Deupree advocates. Moreover, adopting OCA's and CAUSE-PA's positions would replace the Commission's prudency standard with an ever-shifting macroeconomic veto. Under their approach, utilities could recover prudently incurred costs only when economic conditions are favorable—a standard untethered from the statute and impossible to administer consistently.

Q. Please respond to OCA Witness Deupree's claim that tariffs have also affected affordability. OCA St. 1, at pp. 18-19.

A. Once again, the general impact of tariffs is irrelevant to the assessment of the Company's proposal, as the Company did not make any specific adjustments to address the potential that these tariffs will increase the cost of its operations. To the extent customers are negatively impacted by tariffs, the Company will be similarly negatively impacted. Nevertheless, and as explained above, the Company has undertaken a number of specific cost containment measures in recent years that have mitigated these impacts on its cost of service.

Q. Is there any other basis to reject Witness Deupree's proposal to rely on a variety of macroeconomic indicators?

A. Yes. Witness Deupree acknowledges in his testimony that for certain of his indicators, the economic impact is "hard to predict" (OCA St. 1, at p. 17), that the "scope and duration of these effects are uncertain" (OCA St. 1, at p. 17), that there is a "mixed picture" (OCA St. 1, at p. 18), and that even Federal Reserve Chairman Powell has said that "nobody knows" what the economic impact will be. OCA St. 1, at p. 17. As previously stated, macroeconomic events fraught with uncertainty as to their impacts do not meet the requirements established by statute, regulation, or Commission precedent, and should not be accepted as a basis for disallowing the legitimate and largely uncontested costs for providing service that are reflected in this proceeding.

Q. Both Witness Deupree and Witness Cicero refer to earnings features of UGI Gas's parent, UGI Corp. OCA St. 1, at pp. 19-20; CAUSE-PA St. No. 1, at pp. 36-39. Please respond.

A. First, the stock price and equity decisions of UGI Corp are impacted by many things beyond the financial health and effectiveness of UGI Gas. Second, as to the suggestion by Witness Deupree that UGI Gas is not in obvious market distress, UGI Gas Witness D'Ascendis evaluates the relative financial health of the Company compared to peer organizations in his testimony. While I do not disagree that UGI Gas is not in market distress today, its current position reflects a decade of thoughtful and balanced decision-making by the PA PUC that was grounded in cost of service ratemaking. Maintaining that financial health going forward requires the same thoughtful and balanced decision-making – not the outright rejection of bedrock principles. Finally, the Commission should not adopt a new standard in which public utilities could only recover prudently incurred costs, if they are in market distress.

Q. Do you have any other observations about Witness Cicero's presentation of UGI's earnings?

A. Yes, I have further observations. First, Witness Cicero presents UGI Utilities, Inc. net income by quarter for calendar years 2021 through 2025 in Table 7 of his testimony. CAUSE-PA St. No. 1, at p. 37. However, the net income reported for the quarter ended September of each year reflects the entire fiscal year's net income, rather than a single quarter's results. As a result, his stated total of $2,039,000,000 is approximately twice the

correct figure — the actual net income for that period is $1,018,000,000. A corrected net income by quarter is provided as UGI Gas Exhibit JRR-3R to my testimony.

Second, Witness Cicero mentions UGI Utilities, Inc.'s dividends to its parent. Notably, the $214 million of dividends paid in calendar years 2021 through 2025 represents just 21% of net income — meaning 79% — the substantial majority — was retained and reinvested in the utility.

Third, Witness Cicero focuses on net income and does not address cash flows. UGI Gas cannot spend net income – it must spend cash to construct the infrastructure needed to ensure that its distribution system is providing safe and reliable service to customers. UGI Utilities, Inc.'s free cash flow[5] for calendar years 2021 through 2025 was ($587,000,000)[6], reflecting that operating cash flow was insufficient to support the Company's level of infrastructure investment. To fill this gap, UGI Utilities, Inc. required additional funding, which was provided through debt issuance and capital contributions from UGI Corp. The Company's financial stability and investment-grade credit profile enable it to access this financing and attract capital contributions, allowing it to continue its critical infrastructure investment on behalf of customers.

Q. Should the Commission consider affordability in this proceeding?

A. The Commission should consider affordability in this proceeding, but it must do so in connection with traditional cost of service ratemaking considerations and not through the incorporation of extraneous and generalized data points that lack any framework or

[5] Free cash flow is defined as operating cash flow less capital expenditures, and measures a company's ability to fund investment without relying on external debt or equity financing. A negative free cash flow indicates that capital expenditures exceeded operating cash flow, requiring the company to seek external funding.

[6] See UGI Gas Exhibit JRR-4R for a schedule of UGI Utilities Inc's free cash flow for this period.

connection to the cost incurred by UGI Gas to provide service to its customers safely and reliably. The Commission can and should evaluate the many ways that UGI Gas has sought to address affordability as part of its cost of service. The Commission can and should evaluate whether UGI Gas's policies and practices adequately meet the needs of customers across income and operational demographics, and whether more can be done to support customer affordability through modifications to programs or policies. The Commission can and should evaluate whether the design of the Company's rates appropriately consider long-standing cost of service principles such as parity and gradualism. Finally, the Commission can and should consider the role that a financially and operationally healthy UGI Gas plays in serving its customers, modernizing its operations, supporting businesses and jobs, and providing a strong economic contribution to the communities it serves and the state's economy. All of these opportunities to consider affordability in the ultimate outcome of UGI Gas's base rate proceeding are consistent with the statutes, regulations, and precedent that the Commission has long used to balance the interests of customers with those of the utility.

B. REBUTTAL REGARDING REGULATORY LAG AND RATEMAKING POLICY

Q. Please summarize the testimony presented by other parties regarding ratemaking policy and concepts applicable to UGI Gas's operations and rates.

A. OCA Witness Deupree and CAUSE-PA Witness Cicero testify to a number of issues regarding ratemaking policy, including testimony on "regulatory lag", criticism of "traditional ratemaking", and concerns regarding the interaction of various rate concepts approved by the legislature and/or the Commission.

Q. What is your reaction to this testimony?

A. OCA and CAUSE-PA offer voluminous testimony that ultimately is not relevant to the evaluation of whether (1) the costs identified by UGI Gas in this proceeding are necessary to serve the public, (2) those costs are prudently incurred, and (3) the methodology for producing the proposed rates based on those costs results in just and reasonable rates for customers.

Q. What is "regulatory lag"?

A. Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels, and when the utility can reflect the change in new rates charged to customers. Witness Deupree offers a number of alternative definitions, but the crux of each focuses on the concept of a timing mismatch.

Q. Has UGI Gas asserted regulatory lag as a basis for rate relief in this case?

A. No, UGI Gas has not asserted regulatory lag as a basis for its request in this proceeding. Despite voluminous testimony on the concept of regulatory lag, Witness Deupree concedes in his testimony that the Company has not offered regulatory lag as a justification for this case. One could search the entirety of the Company's direct testimony in this case and find that the term "regulatory lag" only appears twice. Indeed, one of the two places where it does appear is in response to one of the factors the Commission considers under its Statement of Policy regarding alternative ratemaking mechanisms, and clearly states that

"[t]he WNA ***does not*** impact the Company's rate case frequency nor does it effect regulatory lag." *See* UGI Gas Exhibit JDT-4, at p. 3 (emphasis added).

Q. Do you have any response to the extensive testimony on regulatory lag?

A. Yes. While this testimony is ultimately extraneous, because it fails to address anything at the core of the Company's proposal, it appears that the testimony offered by both of these witnesses fails for three primary reasons. First, both witnesses fail to assess whether the generic principles they cite are applicable to Pennsylvania. Pennsylvania has codified mechanisms that seek to reduce regulatory lag in key areas, including the FPFTY and Distribution System Improvement Charge ("DSIC") reflected in Act 11 of Feb. 14, 2012, Pub. L. 72, No. 11 ("Act 11"), and the codification of riders for certain components of service (e.g., Purchased Gas Costs pursuant to 66 Pa.C.S. 1307(f)). The adoption of Act 11, in particular, indicates a policy commitment to providing real-time cost recovery to utilities to facilitate investment in facilities needed to provide safe and reliable service.

Second, both witnesses – but particularly Witness Deupree – fail to situate the various broader studies referenced with the present-day operating conditions experienced by UGI Gas in Pennsylvania to determine whether their conclusions regarding management of regulatory lag would apply. For utilities undertaking significant capital replacement programs, such as those currently being pursued by UGI Gas, reflecting only historic plant in service at the time of new rates does not reflect the anticipated operating conditions that will exist during the rate effective period.

Third, as highlighted by Witness Deupree in his testimony describing the concept of regulatory lag as a benefit, he points to two additional key elements that must exist: "(1)

the possibility of disallowances through the prudence review process and (2) the positive efficiency incentives created by regulatory lag." OCA St 1, at p. 25. However, no party to this proceeding has identified imprudently incurred costs, including no disallowances to the $468 million of planned investment in the test year. Similarly, no opportunities for positive efficiencies exist for things such as future deployment of capital needed to support safe and reliable service, or deviations from the normal weather reflected in the development of volumetric rates.

Q. Do you have other concerns with how OCA Witness Deupree and CAUSE-PA Witness Cicero describe regulatory lag?

A. Yes. Both witnesses appear to confuse revenue lost (or gained) in an individual year due to weather with cost recovery elements established in a base rate case that would be subject to regulatory lag. To be clear, to my knowledge, the Company has never adjusted the revenue requirement in its rate cases to collect historic unrecovered revenues due to weather or to remit over recovery. Individual yearly performances for revenues and expenses are treated as non-recurring. As a result, the credits/surcharges produced by the WNA are not a product of regulatory lag. They are simply an overcollection or shortfall that would never be corrected in a future proceeding, but for the WNA.

Q. Does the Company utilize ratemaking mechanisms that are permitted under Pennsylvania law to address regulatory lag?

A. Yes. The Company utilizes the FPFTY and the DSIC. I note, however, that the existence of the DSIC does not avoid the need for base rate cases or dictate that a utility must use the

DSIC up to the 5% cap rather than availing itself of base rate relief. The WNA, however, is not a tool to address regulatory lag for the reasons I have previously described.

Q. What is your response to OCA Witness Deupree's testimony regarding how the Company has "frame[d]" its request? OCA St. 1, at p. 20.

A. Mr. Deupree incorrectly suggests that the Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. That is not the Company's position nor its testimony. Rather, UGI Gas has utilized the existing Pennsylvania framework to expeditiously replace hundreds of miles of cast iron and bare steel pipe. In fact, this month it will retire the final mile of known cast iron main from its system – an accomplishment that would not have been possible in such a short amount of time without the framework in Pennsylvania that unleashed the capital necessary to transform the safety and reliability of the system. UGI Gas has filed this base rate case to ensure these necessary and important investments can continue to be made for the improvement of its system and the service it provides, and it has done so in compliance with all applicable regulatory requirements imposed by the Pennsylvania framework.

Q. Based on your review of Mr. Deupree's testimony, what appears to be his goal by focusing on "regulatory lag"?

A. Besides establishing a strawman that he can attack to avoid the cost of service basis for the Company's requests, he appears to be offering his critique of regulatory lag as a basis to argue alternative ratemaking measures not proposed by UGI Gas should be adopted in this

proceeding. He specifically takes issue with the Company not "propos[ing] any corresponding ratepayer protections such as earnings tests, revenue caps, or performance incentives" as a part of this case. OCA St. 1, at p. 28. It is my understanding that an alternative ratemaking measure can only be proposed by a utility and that UGI Gas will fully address this issue on brief. Mr. Deupree's statement ignores that a base rate proceeding is intended to establish the very items he identifies – allowed earnings, the necessary revenue requirement, and identification of service or operational issues that the Commission determines require modification. These are established for the period when rates are intended to be effective. Further, the mechanisms the Company operates under have ratepayer protections built in through legislative action. *See, e.g.,* Act 11.

Q. Are there problems with Mr. Deupree's comments regarding the ability of utilities to control the timing of their rate cases? OCA St. 1, at p. 28.

A. Yes. While it is true the utility controls the timing of base rate cases, this control is weakened where a utility must sustain a decades-long infrastructure replacement initiative. The idea that strategic timing of a rate case can benefit the utility presumes that the utility can shift or accelerate its spending into the test year, have its rates set on that basis, and then reduce its spending. Where a utility is continuously deploying tens to hundreds of millions of dollars of capital each year, the capital drives a revenue shortfall that eliminates the ability to strategically inflate a test year.

Q. Please describe Witness Cicero's testimony on ratemaking mechanisms.

A. Witness Cicero discusses "traditional cost of service ratemaking," and various ratemaking mechanisms available to UGI Gas and other utilities under Pennsylvania law (e.g., the FPFTY and DSIC). *See* CAUSE-PA St. No. 1, at pp. 10-15. He then argues that "UGI's combined use of multiple alternative rate mechanisms has a compounding negative impact on consumers" due to the use of the FPFTY (which may differ from actual expenditures and produces a reduced risk that "should result in a lower return on equity"), the use of the WNA (which "spread[s] risks to consumers that were historically born [sic] by UGI"), and the use of the DSIC (which "[d]epending on how long UGI stays out of rate cases in the future, . . . has the potential to result in significant additional dollars charged to residential customers" and "shifts future risks onto consumers because it reduces PPL's[sic] risk that rates set in this case will be insufficient to meet its planned capital plant investments" and, therefore, "should result the ROE required by UGI on its overall ratemaking rate base"). CAUSE-PA St. No. 1, at pp. 12-15.

Q. Do you have any initial comments regarding Witness Cicero's testimony on traditional cost of service ratemaking?

A. Yes. Witness Cicero appears to characterize traditional cost of service ratemaking as a methodology that purposefully injects risk as to the ability to recover costs into the dynamic, which suggests the use of a future or historic test year. He appears to posit that Pennsylvania no longer has traditional ratemaking as a result of adopting the FPFTY, and other alternative mechanisms. I disagree with Witness Cicero on two fronts – that the FPFTY is not traditional cost of service ratemaking and that risk of recovery reflects a public policy benefit. The FPFTY utilizes all the core components of cost of service

ratemaking, and actually better approximates a key principle of traditional ratemaking, that the costs included in rates reflect the operating conditions in the rate effective period. Turning to Witness Cicero's contention that the risk of non-recovery is a public benefit, that contention inherently assumes imprudent behavior. But the costs recovered pursuant to the DSIC and the WNA reflect previously reviewed and authorized infrastructure investments or the authorized cost of service as established in a base rate proceeding.

Q. Do you agree with Witness Cicero's contentions regarding the compounding impacts on consumers of the FPFTY, DSIC, and WNA?

A. No, I do not. First, it is appropriate to separate the FPFTY and DSIC from the WNA, as these mechanisms address very different components. The FPFTY and the DSIC are legislatively created mechanisms with a specific public purpose, to facilitate the accelerated replacement of vintage infrastructure to ensure safe and reliable service continues. As previously described, and as specifically identified in the direct testimony of UGI Gas Witness John Taylor, the WNA does not reduce regulatory lag. However, to the primary point of Witness Cicero's testimony, I disagree with his contention that these mechanisms are independently negative for consumers or that they compound in a way that is negative, as shown by the analysis in the rebuttal testimony of UGI Gas Witness Taylor. They allow a utility to conduct critical safety work uninterrupted, and to recover the approved costs needed to provide service without over recovering on those costs to the detriment of customers.

Q. Please respond to Witness Cicero's claim that higher approved rates in this proceeding will increase the DSIC revenues UGI Gas can collect and reduce risk in future cases. CAUSE-PA St. No. 1, at p. 15.

A. On a technical level, Witness Cicero is correct that the function of the DSIC mechanism is capped at 5% of billed distribution revenue, and therefore higher base rates would allow more capital to be recovered through the DSIC before the Company would exceed the cap. However, this mathematical feature of the DSIC is not germane as to whether the costs proposed in this proceeding are necessary or prudent. Further, to the extent Witness Cicero's testimony opposes the use of the DSIC because it reduces the likelihood of a disallowance, this is once again a clear policy decision that recognizes that certain investments made by the utility deserve the presumption that they are in the public interest.

Q. Is there any merit to Witness Cicero's claim that the Company does not need a rate increase because it received a rate increase last year? CAUSE-PA St. No. 1, at pp. 35-36.

A. No. As I noted earlier in my testimony, the Company is investing $468 million in infrastructure in the FPFTY, alone, and has experienced other cost increases impacting the overall cost of service reflected in this case. Witness Cicero's testimony seems to ignore the concept of a test year and a rate effective period, and relies instead on the position that the magnitude of and recency of a prior rate increase based on a different test year and different operating circumstances, is sufficient to reject UGI Gas's proposal. This can be contrasted with his proposal to rely on recent and projected general economic pressures to assess the ability of customers to afford a rate increase. Witness Cicero's rejection of the

Company's proposal without an assessment of the operating circumstances likely to be incurred in the test year does not provide a basis for a sound and unbiased conclusion and should be rejected.

Q. Do you have any other concerns with the approach advocated by Witness Cicero and Witness Deupree?

A. Yes, I do. For payment troubled customers, the customer group both OCA and CAUSE-PA focus much of their testimony on, there will never be a good time for a rate increase and rate increases will always strain their ability to pay without additional assistance from either government-run or utility-run programs. This dynamic is described fully in UGI Gas Witness Fang's testimony. Further, even when the economy is uncertain and world events are occurring, the utility must keep operating and must maintain safe and reliable service with an eye towards decades of future operations. Cost of service ratemaking provides the platform for ensuring that the utility has what it needs to keep operating, and to operate in a manner that is focused on providing safe, reliable and affordable service. The lack of adequate rate relief can pose a significant risk to both near and long-range projects, increasing their cost, or causing an erosion to the quality of service experienced by customers.

Q. Please summarize your testimony regarding the other parties' claims regarding ratemaking policy and its application to this case.

A. The other parties' arguments on ratemaking policy, while extensive, have no application to this case. The testimony should be rejected.

V. CHOICE PROGRAM

Q. What is the Choice program?

A. The Choice program offered by UGI Gas facilitates residential and small commercial shopping, as required by statute. As part of this program, UGI Gas provides a Price To Compare ("PTC") that allows customers to easily compare the price of gas supply offered by the Company with other Natural Gas Suppliers ("NGSs") offering gas supply services in UGI Gas's service territory. As part of the Choice program, UGI Gas offers a Purchase Of Receivables ("POR") program, where UGI Gas purchases the uncollected receivables from participating suppliers and assumes responsibility for billing the customer and collecting the associated revenue.

Q. Did any parties raise concerns regarding the Choice program?

A. Yes. OCA Witness Alexander and CAUSE-PA Witness Cicero identified concerns with and proposed modifications to the Company's Choice program. Witness Alexander's testimony focuses on communications with customers around the PTC and is addressed by UGI Gas Witness Adamo. Witness Cicero proposes that the Company cease offering to purchase receivables that are above the PTC (also referred to as the default service price) as of January 1, 2027.

Q. What is the basis of Witness Cicero's proposal?

A. Witness Cicero points to data produced by UGI Gas in discovery indicating that a substantial number of customers participating in the Choice program are paying prices higher than the PTC. Witness Cicero argues that the POR program removes the risk

proposed by uncollectible costs from suppliers, which leaves them with little incentive to moderate the prices that they charge customers. CAUSE-PA St. 1, at pp. 87-88.

Q. What is the Company's response?

A. UGI Gas offers its POR program consistent with the Commission's regulations and requirements. I commend Witness Cicero for focusing on an area where many customers are paying excessive costs that do not produce any incremental benefits in safety or service quality. However, NGS rates in many instances are more volatile and, even assuming the same supplier, may be set at different levels for different customers. It is not clear whether a single instance of a price above the PTC should result in exclusion from the POR program, and whether such an exclusion would be temporary (i.e., only so long as the customer charges were above the PTC) or permanent. Finally, the Company would need to evaluate the time and cost of any IT programming necessary to facilitate the structure of a modified POR program, which could be structurally difficult to administer if it moved suppliers on and off the POR program based on monthly variations in rates.

VI. PUBLIC INPUT HEARINGS

Q. Did you attend any of the public input hearings?

A. Yes, I attended 10 of the 12 public input hearings. I was unable to attend the public input hearings in Wilkes Barre, but two members of my team – including UGI Gas Witness Tracy Hazenstab – attended those public input hearings on my behalf. Beyond my team, each public input hearing was attended by a number of other UGI Gas representatives, including members of the Customer Service team.

Q. Please provide a summary of what you observed at the public input hearings.

A. In total, 27 individuals testified, ranging from 8 witnesses testifying in a single hearing to no witnesses testifying, which occurred at 3 of the 12 hearings. Consistent with my past experience, the predominant theme raised by those testifying focused on the affordability of natural gas service, with many witnesses expressing concern not about their own bills, but those of others in the community who may struggle with affordability. Only two individuals testifying raised issues specific to their experienced service with the Company, one as to operations in the field and the other as to call center service. UGI Gas reviewed both of these circumstances. As OCA Witness Teti discusses the operational concerns raised by Mr. Ivan Ritz (OCA St. 7, at p. 11), a review of the associated events is addressed by UGI Gas Witness Jill Walter.

Q. Did you review OCA Witness Teti's testimony regarding the public input hearings?

A. Yes, I did.

Q. Is it appropriate for Witness Teti to draw widespread conclusions based on limited public input hearing testimony?

A. No, it is not. While anecdotal information can be useful, and UGI Gas appreciates and evaluates the testimony provided at public input hearings, UGI Gas serves more than 700,000 customers. The small number of individuals that testified at the public input hearings is not, in my view, representative of widespread customer sentiment. In addition, based on my experience, I do not agree with the characterizations of certain public input hearing testimony supplied by Witness Teti.

VII. CONCLUSION

Q. Please summarize the conclusions made in your rebuttal testimony.

A. UGI Gas acknowledges that affordability is a central consideration in utility ratemaking, and one that the Commission has always evaluated with an eye toward thoughtfully balancing the need for reliable and affordable service for customers with the need for rate relief that will provide the Company with the revenue allowing it to maintain safe and reliable service and have a reasonable opportunity to earn a fair rate of return. The Commission should utilize its traditional approach to cost of service ratemaking, as it reflects the best methodology for ensuring long-term affordability while maintaining financially healthy utilities. While OCA and CAUSE-PA have submitted voluminous testimony pointing to a variety of world events and macroeconomic concerns, they do not identify how those concerns relate to the Company's cost of service, or how the Commission should evaluate the impacts of the various factors in its ratemaking process. OCA and CAUSE-PA do not seek to strike any balance by rejecting the statutory and regulatory framework, and long-standing Commission precedent, to achieve their proposals of no rate increase.

Q. Has the Company thoughtfully approached the impact to ratepayers that will result from this proceeding?

A. Yes. The Company has exercised its judgment in numerous ways in operating its business and in developing this case to appropriately manage the costs passed on to ratepayers. UGI Gas's proposed cost of service recognizes that customers need to have safe, affordable and reliable service, which can only be provided through the continued modernization of aging infrastructure.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit JRR-1R

JESSICA R. ROGERS
UGI UTILITIES, INC.
VICE PRESIDENT – RATES & REGULATORY AFFAIRS

Summary

Rates, regulatory, energy and climate strategy expert with over 15 years of experience in natural gas and electric distribution administrative agency cases. Experience includes cases filed in Pennsylvania, Maryland, Virginia, Michigan, and Washington, DC, the Federal Energy Regulatory Commission and the Surface Transportation Board, as well as appellate experience.

As Vice President – Rates & Regulatory Affairs:

- Leads a team responsible for all rate and regulatory filings for gas and electric utilities before the Pennsylvania Public Utility Commission, the Maryland Public Service Commission, and the Federal Energy Regulatory Commission.
- Develops policy positions and legislative responses for gas and electric utilities for all areas of operations.

Employment History

UGI Utilities, Inc. Vice President – Rates & Regulatory Affairs (Denver, PA)	September 2025 – Present
Washington Gas Light Company Vice President – Regulatory & Climate Strategy (Washington, DC)	June 2024 – August 2025
UGI Utilities, Inc. Senior Director – Rates & Regulatory Strategy (Denver, PA)	September 2023 – May 2024
UGI Utilities, Inc. Director – Regulatory Strategy (Denver, PA)	February 2021 – August 2023
Post & Schell, P.C. Of Counsel (Washington, DC)	June 2020 – February 2021
Post & Schell, P.C. Senior Associate (Washington, DC)	September 2014 – May 2020
Post & Schell, Associate (Harrisburg, PA)	September 2010 – August 2014

Education

Juris Doctorate, University of Virginia, Charlottesville, VA	2010
BA, Communications Studies and English, University of California Los Angeles, Westwood, CA	2005

Prior testimony:

DC Public Service Commission, Washington Gas Light Company, Formal Case No. 1179
MD Public Service Commission, UGI Utilities, Inc. – Gas Division, Formal Case No. 9707
PA Public Utility Commission, UGI Utilities, Inc. – Electric Division, Docket No. R-2025-3059430

Professional Licenses:

Member of the Bar, Pennsylvania
Member of the Bar, Washington, DC

UGI Gas Exhibit JRR-2R

UGI Utilities, Inc. - Gas Division
Operating Expenses and CPI
Fiscal Years 2018 - 2027
($s in millions)

	2018	2019	2020	2021	2022	2023 *	2024	2025	2026	2027	2018 - 2027
	Actual	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Actual*	*Budget*	*Budget*	**CAGR ****
Salaries and Wages	$ 68	$ 71	$ 71	$ 71	$ 67	$ 70	$ 72	$ 74	$ 77	$ 82	
Employee Benefits	$ 21	$ 20	$ 19	$ 19	$ 19	$ 20	$ 20	$ 21	$ 21	$ 22	
Transportation	$ 6	$ 7	$ 5	$ 4	$ 4	$ 6	$ 6	$ 5	$ 5	$ 6	
Contracted Labor	$ 23	$ 20	$ 17	$ 17	$ 20	$ 25	$ 25	$ 25	$ 29	$ 31	
Other Professional Services	$ 10	$ 11	$ 13	$ 11	$ 10	$ 9	$ 10	$ 11	$ 10	$ 11	
Materials, Equipment and Maintenance	$ 13	$ 15	$ 15	$ 15	$ 17	$ 16	$ 15	$ 16	$ 16	$ 16	
Information Technology	$ 15	$ 18	$ 19	$ 18	$ 17	$ 18	$ 19	$ 19	$ 19	$ 20	
Bad Debt	$ 16	$ 14	$ 12	$ 12	$ 14	$ 21	$ 16	$ 17	$ 20	$ 21	
Administrative and General	$ 27	$ 24	$ 24	$ 24	$ 24	$ 27	$ 26	$ 27	$ 25	$ 27	
Taxes Other than Income & GRT	$ 8	$ 11	$ 9	$ 9	$ 10	$ 11	$ 13	$ 13	$ 13	$ 14	
Corporate Allocation	$ 13	$ 12	$ 13	$ 19	$ 20	$ 20	$ 20	$ 28	$ 29	$ 30	
Total Operating Expenses	**$ 220**	**$ 223**	**$ 216**	**$ 220**	**$ 220**	**$ 244**	**$ 242**	**$ 255**	**$ 265**	**$ 279**	**2.7%**
Consumer Price Index (CPI) (12-months ended September 30,)	252	257	260	274	297	308	315	325	336	347	3.6%

Source: https://www.bls.gov/regions/mid-atlantic/data/consumerpriceindexhistorical_us_table.htm
2026 and 2027 CPI is increased by 3.3% per year (as reported for March 2026).

* FY2023 Actuals included significant adjustments due to the renegotiation of union contracts, an update to salaries to align with industry benchmarking, and an increase in bad debt expense due to the conclusion of the COVID-19 termination moratorium. These were described in the Company's testimony in Docket No. R-2021-3030218.

** Compound Annual Growth Rate

UGI Gas Exhibit JRR-3R

UGI Utilities, Inc.
Net Income by Quarter
January 2021 - December 2025

Quarter Ending	Net Income (Loss)
Mar-21	$99,000,000
Jun-21	$9,000,000
Sep-21	($11,000,000)
Dec-21	$57,000,000
Mar-22	$115,000,000
Jun-22	$19,000,000
Sep-22	$4,000,000
Dec-22	$73,000,000
Mar-23	$129,000,000
Jun-23	$13,000,000
Sep-23	($9,000,000)
Dec-23	$80,000,000
Mar-24	$135,000,000
Jun-24	$14,000,000
Sep-24	($10,000,000)
Dec-24	$79,000,000
Mar-25	$142,000,000
Jun-25	$8,000,000
Sep-25	($16,000,000)
Dec-25	$88,000,000
Total	**$1,018,000,000**

Source: UGI Utilities, Inc. financial statements

Publicly available at: https://www.ugicorp.com/investors/financial-reports/ugi-utilities

UGI Gas Exhibit JRR-4R

UGI Utilities, Inc.
Free Cash Flow
January 2021 - December 2025

Period	A Operating Cash Flow	B Investing Cash Flow	A - B Free Cash Flow
Quarter 2 - Quarter 4 Fiscal Year 2021	$255,000,000	($297,000,000)	($42,000,000)
Fiscal Year 2022	$267,000,000	($470,000,000)	($203,000,000)
Fiscal Year 2023	$431,000,000	($520,000,000)	($89,000,000)
Fiscal Year 2024	$349,000,000	($411,000,000)	($62,000,000)
Fiscal Year 2025	$365,000,000	($474,000,000)	($109,000,000)
Quarter 1 Fiscal Year 2026	$56,000,000	($138,000,000)	($82,000,000)
Total	**$1,723,000,000**	**($2,310,000,000)**	**($587,000,000)**

Source: UGI Utilities, Inc. financial statements

Publicly available at: https://www.ugicorp.com/investors/financial-reports/ugi-utilities

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 16-R

Rebuttal Testimony of
Cyndee S. Fang, Director
Atrium Economics, LLC

Topics Addressed:

Scope of Utility Responsibility to Address General Affordability Concerns
Role of Utility Assistance Programs
Program Enrollment and Design

Dated: May 13, 2026

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Cynthia S. Fang. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics as a Director.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. No, I did not. However, this rebuttal testimony is submitted in response to the direct testimony filed by certain other parties in this proceeding. My rebuttal testimony explains that utility ratemaking is not a reasonable mechanism for addressing economywide inflationary pressures or other macroeconomic conditions, and that energy affordability concerns are more appropriately addressed through Pennsylvania Public Utility Commission ("PUC" or "Commission")-approved, targeted universal service programs that are the subject of separate proceedings designed to specifically address those issues.

Q. Please describe your professional background and education.

A. I have over 20 years of experience in the energy industry focusing on regulatory, cost recovery and rate design issues. I joined Atrium Economics in December 2024. Before joining Atrium Economics, I was Vice President of Regulatory at NorthWestern Energy. In this role I was responsible for the development and execution of the Company's regulatory strategy in Montana, South Dakota, and Nebraska. I joined NorthWestern

Energy in 2021 as the Director of Regulatory Affairs in Montana. Prior to NorthWestern Energy, I held various leadership roles at San Diego Gas & Electric, which included overseeing the Company's electric rate strategy as well as electric forecasting, electric load analysis and research, and origination teams. I began my career in the energy industry as a Public Utilities Rates Analyst at the Minnesota Department of Commerce, Energy Division. I received my Bachelor of Science in Political Economics of Natural Resources from the University of California at Berkley and completed all coursework required for a Ph.D. in Applied Economics at the University of Minnesota, focusing on environmental economics. A copy of my resume is provided as UGI Gas Exhibit CSF-1R.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by the other parties listed below, specific to affordability issues that are experienced by residential customers:

- Office of Consumer Advocate ("OCA")
  - Statement No. 1 – direct testimony of Michael Deupree ("OCA witness Deupree" or Mr. Deupree);
  - Statement No. 6 – direct testimony of Roger Colton ("OCA witness Colton" or Mr. Colton); and
  - Statement No. 7 – direct testimony of Zach Teti ("OCA witness Teti" or Mr. Teti).
- Coalition For Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1 – direct testimony of witness Patrick M. Cicero ("CAUSE-PA witness Cicero" or Mr. Cicero").

Q. Please summarize the principal affordability-related positions advanced by the intervenor witnesses you address in this rebuttal testimony.

A. OCA Witness Deupree places the Company's requested increase within the broader context of persistent inflation, rising costs of other household necessities, and the cumulative impact of recent utility bill increases. He urges the Commission to give consideration to those macroeconomic conditions in evaluating the reasonableness of the Company's proposal and contends that residential and small general service customers should not bear a purportedly disproportionate share of additional rate increases under current economic circumstances.[1]

OCA Witness Colton presents an affordability analysis intended to show that UGI Gas's residential bills are already increasingly difficult for low-income and moderate-income households to manage and that the proposed rate increase would worsen those conditions. He asserts that the Company's rates have risen sharply in recent years, that many households lack the income and liquid financial resources necessary to absorb additional bill increases or seasonal volatility, and that the Company should expand customer protections and affordability-related assistance efforts.[2]

OCA Witness Teti states that his testimony is intended to reflect the concerns expressed by residential customers and public officials during the public input hearings, where affordability was the dominant issue raised. He reports that witnesses repeatedly described financial hardship, difficulty managing rising household expenses, and concern that many customers cannot reasonably absorb another utility increase. Mr. Teti further

[1] OCA St. 1, pp. 7-20.
[2] OCA St. 6, pp. 5, 41, 51.

notes that public witnesses expressed a perception that the proposed increase places customer hardship secondary to shareholder interests.[3]

CAUSE-PA Witness Patrick Cicero asserts that affordability remains a serious and ongoing problem for low-income customers, particularly those not enrolled in CAP, many of whom cannot consistently afford gas service at current rates. He emphasizes that gaps in program participation and coverage leave a substantial number of vulnerable households exposed to payment difficulty, arrearages, and service termination, and that existing assistance structures do not sufficiently protect customers from unaffordable bills. Cicero urges the Commission to evaluate affordability based on actual customer outcomes and to place greater emphasis on universal service program effectiveness, accessibility, and enrollment, rather than assuming current program frameworks adequately address customer need.

Q. Are you the only UGI Gas witness that is addressing affordability issues raised by other parties in their direct testimony?

A. No, I am not. I note that UGI Gas Witness Rogers (UGI Gas Statement No. 15-R) addresses various of the arguments raised by OCA Witness Deupree and CAUSE-PA Witness Cicero regarding affordability, macroeconomic conditions, and ratemaking policy. In addition, UGI Gas Witness Meilinger (UGI Gas Statement No. 12-R) responds to the testimony of OCA and CAUSE-PA related to the Company's Universal Service Programs, the Company's performance with respect to the administration of those programs, and how those programs are designed to help and do help low-income customers manage their utility

[3] OCA St. 7, pp. 2-9.

bills. Finally, responses to parties' concerns about potential affordability impacts of the Company's rate design proposals or weather normalization mechanisms are addressed by Company Witness John D. Taylor (UGI Gas Statement No. 11-R).

Q. Are you sponsoring any exhibits other than UGI Gas Exhibit CSF-1R with your rebuttal testimony?

A. No, I am not.

II. SCOPE OF UTILITY RESPONSIBILITY

Q. Please summarize the intervenor perceived scope of a regulated utility's responsibility for addressing affordability concerns through base rates.

A. Intervenors contend that, because household budgets are strained by rising costs for housing, food, healthcare, and other necessities, utilities should take on a broader role in addressing overall affordability through base rates.[4]

Q. Do you agree with how parties have characterized the scope of a regulated utility's responsibility for addressing broader affordability concerns through base rates?

A. No. The parties misconstrue the scope of utility regulation. The Commission's statutory obligation is to ensure that utility rates are just and reasonable based on the prudent costs of providing utility service; it does not extend to requiring utilities to offset or internalize macroeconomic conditions unrelated to the provision of regulated utility service. Expanding utility responsibility to address economywide affordability pressures would

[4] *See, e.g.*, OCA St. 1, pp. 3-7, 4-19; OCA St. 6, pp. 5-41; OCA St. 7, p. 4; OSBA St. No. 1, p. 2-3; CAUSE-PA St. No. 1, pp. 25-34.

improperly transform ratemaking into a general social policy tool, contrary to long-standing cost-of-service principles embedded in state law.

Q. How does the existing customer protection and assistance framework inform the boundaries of utility responsibility for affordability?

A. The regulatory framework includes well-established customer protection and assistance tools that address payment difficulty in a focused, practical way— through clear rules for: billing (52 Pa. Code § 56.11 et seq.), collections and payment arrangements (52 Pa. Code § 56.191), and termination (52 Pa. Code §§ 56.81, 56.91); and low-income assistance programs and universal service plans (52 Pa. Code § 62.1 et seq.). Those tools are designed to help customers maintain service on reasonable terms while also protecting timely paying customers from undue cost shifting. Importantly, this framework does not treat utilities as responsible for offsetting the full range of household cost pressures (such as housing, food, or healthcare) through base rates. Instead, it reflects a policy choice to address utility affordability through targeted mechanisms within utility regulation, rather than by changing core, cost-based ratemaking principles. Consistent with that structure, the Commission's role in rate regulation is to balance the interests of customers and the utility by establishing just and reasonable rates based on the cost of providing regulated service, while ensuring the utility can maintain safe and reliable operations over the long term

Further, Pennsylvania's affordability challenges are best advanced through a coordinated, statewide approach across essential utility services—including coordinated efforts across multiple Pennsylvania natural gas and electric utilities—building on the Commission's affordability proceeding at Docket No. M-2017-2587711 and the January

2019 staff affordability study as an initial step. Accordingly, material program changes should be pursued through universal service proceedings and appropriate rulemaking or policy processes, rather than through ad hoc modifications in a base rate case.

Q. What Commission-approved mechanisms are intended to address utility affordability concerns?

A. The regulatory framework includes a structured and Commission-approved approach for addressing utility affordability through Universal Service Programs, including Customer Assistance Programs ("CAPs"). Commission regulations identify CAPs as an alternative collection method designed to align customer payments with ability to pay, reduce arrearages, and maintain access to essential utility service for low-income households (52 Pa. Code § 69.261). These programs are evaluated, approved, and modified through formal Commission proceedings and are the appropriate vehicle for addressing affordability concerns within utility regulation. Requiring utilities to address broader macroeconomic hardship not related to the cost of service through base rates would bypass this established framework and undermine the purpose of targeted assistance. In addition, the Commission-approved Universal Service Program framework—particularly those program components funded by other ratepayers—already reflects a balancing of the interests of differently situated customers, with those approved program costs incorporated in the Company's cost of service.

Q. Should utility ratemaking be used as a substitute for broader social policy or to counteract external inflationary pressures?

A. No. While utility rates can and should consider impacts on vulnerable customers, ratemaking principles are grounded in cost causation, rate stability, and understandability; they should not obligate utilities to resolve broader macroeconomic disparities through base rates. Using utility rates as a substitute for social welfare policy would erode cost causation, create inequitable cross-subsidies, and ultimately increase costs for customers who are not the intended beneficiaries of affordability relief. Pennsylvania's regulatory framework already includes targeted Universal Service Programs that address payment difficulty for income-eligible customers, with costs that are reviewed by the Commission and incorporated into rates. The issue raised by intervenors is not whether those targeted tools should exist, but whether utility base rates should be further expanded to serve as a substitute for state-developed and administered social welfare policy or to counteract broader economywide inflationary pressures. Over time, using base rates to absorb economywide affordability pressures would ultimately increase total costs borne by customers.

Moreover, in Pennsylvania—where customers are served by numerous electric and gas utilities—attempting to pursue macroeconomic affordability objectives through individual utility rate cases could lead to inconsistent outcomes across service territories and raise avoidable fairness concerns for customers statewide.

Q. How is limiting affordability obligations to targeted low-income programs consistent with the Commission's just and reasonable standard?

A. Limiting utility affordability obligations to existing low-income programs is consistent with the Commission's just-and-reasonable standard. Universal Service Programs allow

the Commission to balance affordability for income-verified customers with protections for non-participating customers, ensuring that assistance is targeted, transparent, and subject to regular oversight. By contrast, holding utilities responsible for mitigating general macroeconomic hardship through base rates would extend beyond the statutory foundation of ratemaking and risk compromising the stability and fairness of rates for all customers.

Proposals to address macroeconomic pressures through a "no increase" outcome in an individual base rate case does not create a solution grounded in cost of service: they do not resolve the underlying economywide drivers of customer hardship, and they would instead shift the burden to the utility by suppressing recovery of prudent costs. Over time, that approach can weaken the Company's financial and operating integrity by increasing regulatory risk, impairing its ability to maintain credit metrics and access capital on reasonable terms, and constraining needed investment in safety, reliability, and compliance—outcomes that can ultimately increase total costs and service risks for all customers over the long run.

Q. What is the appropriate role of the Commission and rate regulation when intervenors raise broader economywide affordability concerns?

A. Intervenors' arguments risk conflating the Commission's regulatory role with broader economic policymaking that lies outside the scope of rate regulation. The Commission's responsibility is to establish just and reasonable rates (66 Pa.C.S. § 1301(a)) based on the cost of providing regulated service, while ensuring the utility can maintain safe and reliable operations over the long term. At the same time, I recognize that many customers are experiencing real affordability pressures and that these concerns warrant careful attention.

However, the Commission is not charged with addressing general macroeconomic conditions or reallocating economywide affordability pressures through utility rates. Instead, the regulatory framework deliberately separates cost-of-service ratemaking from targeted Universal Service Programs, which are designed to address affordability concerns in a structured and transparent manner. Preserving this distinction helps maintain regulatory certainty, protects non-participating customers from undue cost shifting, and ensures affordability policy is administered through Commission-approved mechanisms rather than through ad hoc modifications to base rates.

Q. What are the implications of using utility rates to address macroeconomic affordability pressures on a utility's ability to earn a fair return and attract capital for necessary investments?

A. Expanding the role of regulation of utility rates to address economywide affordability pressures by suppressing or denying recovery of prudent costs would increase regulatory uncertainty and weaken the link between the cost of service and rates. Over time, that approach can impair a utility's opportunity to achieve a fair rate of return, which in turn can increase the Company's cost of capital and hinder access to financing on reasonable terms. Those outcomes directly affect customers because safe and reliable service depends on continued investment in distribution infrastructure, system integrity, and compliance with safety and environmental requirements. Maintaining traditional cost-based ratemaking, while addressing affordability through targeted assistance and program design, supports both customer protections and the Company's ability to attract capital for the

investments necessary to provide safe and reliable service. This is discussed further by Company Witness Rogers.

Q. Even during periods of broad macroeconomic challenge, how should the Commission approach a base rate case?

A. The Commission should apply the established just-and-reasonable standard by evaluating whether the Company's rates are supported by the prudent costs of providing regulated service and are sufficient to allow the Company to continue providing safe, reliable, and compliant service to the public. Macroeconomic conditions may heighten the importance of targeted assistance and customer protections, but they should not displace the cost-of-service and prudence framework that governs the Commission's determination of the Company's revenue requirement in a base rate proceeding. In this case, the intervenors' affordability arguments do not challenge the prudence of the Company's claimed distribution costs; rather, they seek to use this proceeding to achieve a "no increase" outcome based on broader economic conditions.

Q. If the prudence of the Company's costs is not being disputed, what is the practical effect of proposals to deny or materially reduce recovery?

A. The practical effect is to shift the burden of economywide affordability pressures onto the utility by suppressing recovery of prudent costs and, in turn, eroding the Company's opportunity to earn its authorized return. Over time, that can weaken financial integrity by increasing regulatory risk, impairing credit quality and access to capital, and constraining the Company's ability to make needed investments in safety, reliability, and compliance.

Those impacts can be significant for all customers because they can increase long-run costs (through higher financing costs, deferred maintenance, or accelerated replacement needs) and raise operational and service risks that a stable, cost-based ratemaking framework is intended to avoid. This is discussed further by Witness Rogers.

Q. Beyond direct service considerations, does a utility's financial and operating integrity have broader local implications?

A. Yes. Utilities are often significant local employers and purchasers of goods and services, and they frequently partner with community organizations on safety, customer assistance outreach, and other initiatives. Maintaining the Company's ability to operate safely and reliably—and to plan and invest on a long-term basis—supports those local first- and second-order economic impacts. That said, those broader considerations do not convert base rate cases into macroeconomic or social welfare proceedings; rather, they reinforce why a stable, cost-based approach to recovery of prudent costs is important to sustaining the essential services that utilities provide. Witness Rogers discusses the first- and second-order impacts of UGI Gas on the communities it serves.

Q. If macroeconomic conditions are contributing to broader affordability pressures, what is the appropriate forum for addressing those issues?

A. To the extent broader macroeconomic conditions are driving household hardship, the most effective tools for addressing those conditions generally lie at the state or federal level through tax policy and broad-based social assistance programs that are designed to be income-targeted and coordinated across essential needs (e.g., housing, food, healthcare,

and energy). If utility rates are expected to absorb or offset broader macroeconomic pressures by suppressing recovery of prudent costs, that creates regulatory uncertainty and can impair the Company's ability to achieve a fair opportunity to earn its authorized rate of return and attract capital on reasonable terms. Those risks ultimately affect customers because continued access to capital supports the investments necessary to maintain safe and reliable service for essential energy needs. Preserving cost-of-service ratemaking while directing affordability relief through targeted public programs and Commission-approved universal service mechanisms provides a more appropriate and effective framework.

Q. OCA Witness Colton presents affordability and energy-burden data indicating that many customers—particularly low-income households—experience high gas burden levels.[5] How do you respond?

A. I recognize that many customers are under real financial strain, and that higher bills can be especially difficult for low-income households with limited flexibility in their budgets. The energy-burden metrics presented by Mr. Colton highlight the real financial pressures many customers face, and they underscore why affordability is an important issue for both the Commission and the Company. Consistent with that concern, the Company supports and administers multiple assistance and universal service programs intended to mitigate bill burdens for vulnerable customers, which is discussed further by Witness Meilinger. This data further reinforces the importance of ensuring that available assistance programs are effective, accessible, and functioning as intended for the customers they are designed to serve.

[5] OCA St. 6, pp. 5-41.

Q. Does Mr. Colton's affordability and energy-burden analysis demonstrate that the Company's proposed rates are unreasonable?

A. No. While Mr. Colton's analysis provides useful insight into customer circumstances, it principally reflects income limitations and broader economic conditions, rather than the prudence of the Company's costs or the level of revenue required to provide safe and reliable service. Affordability and energy-burden metrics help illustrate why effective assistance programs are critical, but they do not supplant the Commission's obligation in a base rate case to determine whether the Company's proposed rates are just and reasonable based on prudent costs. Viewed in that context, Mr. Colton's testimony supports continued attention to the effectiveness and design of assistance programs, which UGI Gas Witness Meilinger addresses, not a conclusion that recovery of prudent costs should be denied.

Q. OCA witness Mr. Colton notes that affordability challenges are exacerbated by seasonal bill volatility, particularly during winter months when usage increases.[6] How do you respond?

A. Mr. Colton is correct that seasonal usage patterns can lead to significant bill volatility, and that large winter bills can create acute cash-flow stress for some customers. This seasonal volatility is most prominent with a rate design that focuses on recovery of utility costs through volumetric rates. As Mr. Colton's testimony explains, this concern is especially pronounced for low-income households that have limited liquid assets and little or no savings cushion, which reduces their ability to absorb short-term bill increases even when

[6] OCA St. 6, pp. 25-26.

annual costs are relatively predictable. This seasonality-driven cash-flow challenge reflects fluctuations in usage, rather than deficiencies in the prudence of the Company's costs or the overall level of rates. To the extent that high winter bills heighten affordability risk, those impacts can be mitigated through rate design approaches that reduce excessive seasonal bill swings by moderating how costs are recovered over the year, while still preserving appropriate price signals. In this way, rate design can help address the timing and variability of bills, while targeted assistance programs address customers' underlying income and liquidity constraints—each serving a complementary role within the Commission's ratemaking framework. Impacts of rate design on affordability are discussed further by Company witness Taylor.

Q. Do the intervenors provide an accurate assessment of the current energy burden of UGI Gas's customers?

A. No. Affordability concerns warrant careful and informed consideration. Given the importance of these issues, a more rigorous, customer-level energy-burden analysis, using consistent definitions and transparent assumptions, would better inform the nature and extent of affordability challenges.

Q. Did Atrium Economics conduct a gas-burden analysis for UGI Gas, and if so, what did it entail?

A. Yes. Atrium Economics conducted a customer-level "gas burden" study, defining gas burden as the percentage of household income spent on the UGI gas bill, with household income proxied using American Community Survey ("ACS") data by mapping each

customer to the median household income of the Census block group in which the customer resides. The analysis used customer billing and usage information for the period August 2024–July 2025 for gas only customers. Customers were then mapped to ACS 2024 5-year block-group median income, and gas burden was calculated as annual gas bill divided by that income proxy. The analysis excludes benefits from customer assistance programs.

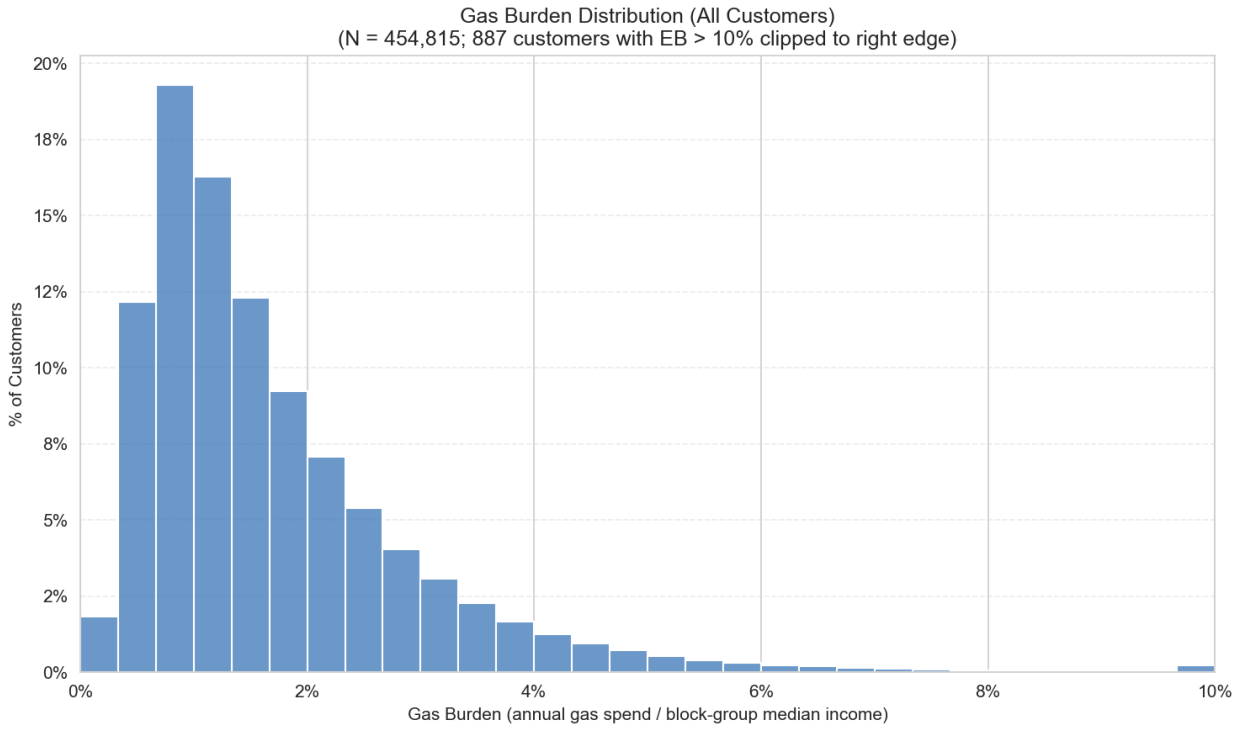
Q. What does Atrium's gas-burden analysis show for UGI Gas customers as a whole?

A. The analysis included 454,815 gas only customers:

- Estimated average annual household income: $83,026
- Estimated median annual household income: $78,082
- Average Annual gas spend: $1,171
- Median annual gas spend: $1,102
- Average annual gas usage: 775 CCF
- Median annual gas usage: 723 CCF

The average gas burden for this group was 1.71% with a median of 1.34% and a maximum energy burden of 25.11%. The results of the gas burden analysis are presented in Figure 1 below.

Figure 1: Distribution of Gas Burden for UGI (Gas Only Customers)



In addition, Table 1 below provides a summary of Figure 1.The distribution shows that the first quartile (25% of customers) has a gas burden of 0.86% or below, the median (50% of customers) is 1.34%, and the third quartile (75% of customers) is 2.17% prior to receiving any benefits from customer assistance programs.

A more granular look at the upper tail shows that 90% of customers have a gas burden ≤ 3.25%, 95% have a gas burden ≤ 4.09%, and 99% have a gas burden ≤ 6.39%. Alternatively, 5.39% or 24,514 customers have a gas burden above 4%, 1.28% or 5,821 have a gas burden above 6% and 0.20 or 909 have a gas burden above 10% prior to receiving any benefits from customer assistance programs.

Table 1: Gas Burden for UGI (Gas Only Customers)

All Customers	
Number of Customers	**454,815**
Average	**1.71%**
First Quartile - 25% of population	**0.86%**
Second Quartile/Median – 50% of population	**1.34%**
Third Quartile – 75 % of population	**2.17%**
90% of population	**3.25%**
95% of population	**4.09%**
99% of population	**6.39%**
Maximum	**25.11%**

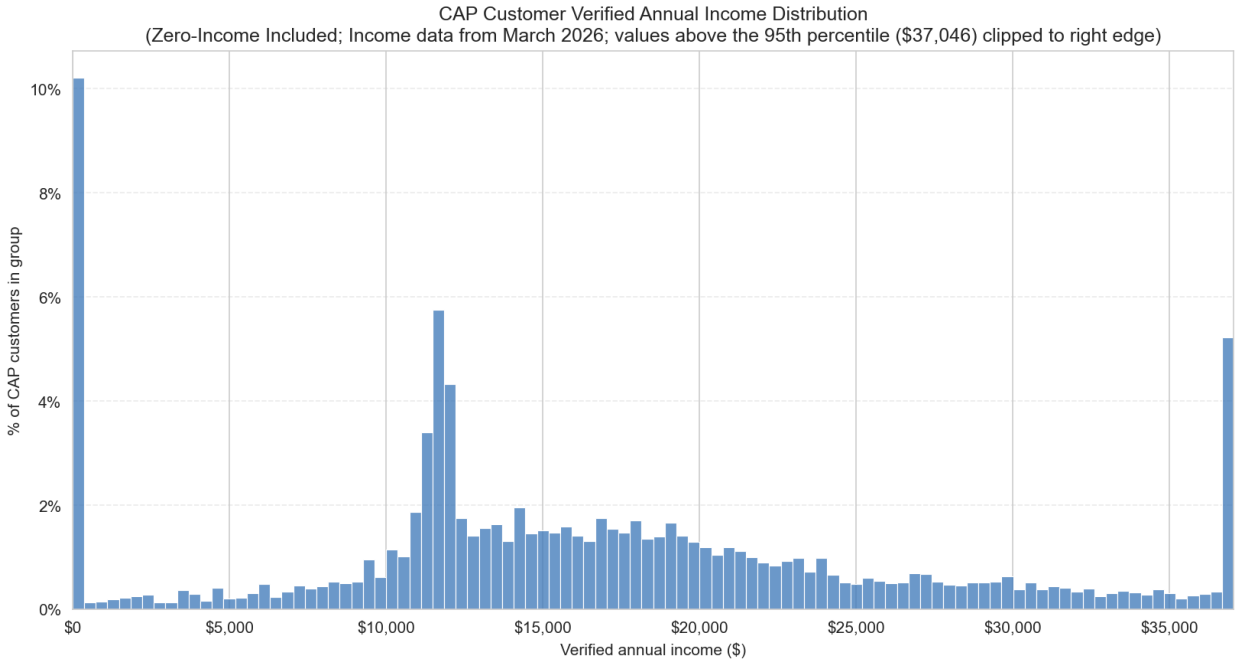
Q. Did Atrium conduct any additional analysis to evaluate the gas burden for UGI Gas's CAP enrolled customers? If so, please describe.

A. While ACS data provides publicly available income estimates that allow for a mapping of each of the Company's customers to the median household income of the Census block group in which the customer resides, those ACS-based estimates may overstate income for low-income customers. Accordingly, Atrium conducted an additional customer-level analysis for UGI's CAP-enrolled gas-only customers using anonymized CAP program data, including:

- **Verified monthly income**, which Atrium annualized by multiplying by 12;
- **CAP bill amount** (monthly, aggregated across the 12-month period), which reflects the with-benefits bill amount charged to a CAP customer; and
- **CAP credit** (monthly, aggregated across the 12-month period), which reflects the difference between the customer's without-benefits bill amount and the with-benefits bill amount charged to the customer.

A CAP customer's without-benefits bill is calculated as CAP bill amount + CAP credit.

Figure 2: Distribution of Annual Income for CAP Enrolled Customers



Atrium's analysis included 13,774 CAP-enrolled gas-only customers with 12 months of CAP bill data; customers with fewer than 12 months of CAP bill data were excluded from the analysis. Figure 2 presents the distribution of annual income for this population. Of the 13,774 customers, 1,396 (approximately 10%) had verified annual income equal to $0.

For all charts within this section, Atrium effectively "clipped" the data at the 95th percentile in an effort to keep the distribution charts legible. The 95th percentile cutoff removes the long, sparse right tail that would otherwise compress the bulk of the distribution into a small portion of the chart. For any chart that includes two distributions (overlaid on top of each other), the cutoff is set to the 95th percentile of the without-CAP benefits group only, since that group is right-shifted relative to the with-CAP benefits group and a combined-group data cutoff would over-clip the without-CAP benefits group

distribution. For the verified annual income chart, the cutoff is the 95th percentile of the income distribution itself. Values above the cutoff are pulled to the cutoff value rather than dropped, so the rightmost bar in each chart reflects both its natural density and the share of customers above the cutoff.

Because gas burden is defined as the ratio of annual gas bill to annual household income, gas burden cannot be calculated for customers with verified annual income of $0 because the metric is undefined (division by zero). This data limitation was also identified in the Commission's report on Home Energy Affordability for Low-Income Customers in Pennsylvania published on January 2019 under Docket No. M-2017-2587711.[7] As noted in that report, there are mathematical limitations when performing an energy burden analysis for customers who enroll in utility CAPs with zero income. Such customers must sign an affidavit at the time of enrollment stating that there is currently no adult receiving income and identify the source of the funds to meet monthly living expenses, such as savings; support from friends, family or community; or other means. The PUC stated

> Customers who enroll in utility CAPs with zero income (zero-income customers) may inflate the average energy burden levels, particularly for the analysis of customers with incomes at or below 50% of the FPIG. Utilities require customers that report zero income to pay the utility's CAP minimum payment amount. Thus, it is not mathematically possible for zero-income customers to receive bills below the maximum energy burden guidelines in the CAP Policy Statement because any billed amount will exceed 100% of their household income.[8]

Due to these limitations, customers enrolled in CAP with zero income have been excluded from this analysis. Pursuant to the Company's approved USECP at Docket Nos. M-2019-

[7] 1602386.pdf
[8] Page 21

3014966 and P-2020-3019196, zero income customers would be subject to the minimum bill requirements for CAP customers which are $15 per month for CAP non-heating customers and $25 per month for CAP heating customers.

Figure 3 presents the income distribution updated to reflect the exclusion of zero income customers.

Figure 3: Distribution of Annual Income for CAP Enrolled Customers Excluding Zero-Income Customers

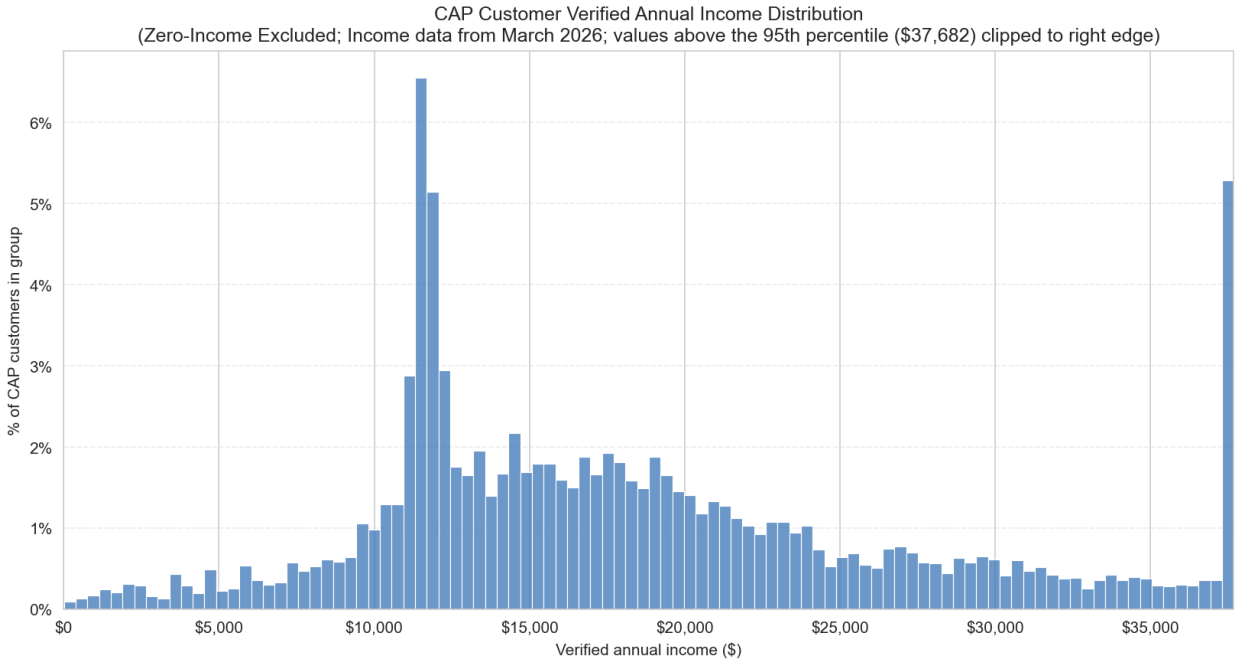


Figure 4 below presents the distribution of gas burden for CAP-enrolled customers with and without CAP benefits. The figure shows that CAP benefits materially reduce gas burden, shifting the distribution downward: mean gas burden falls from 13.02% without benefits to 5.85% with benefits, with similar reductions at the median (7.60% to 5.47%) and the upper tail (95th percentile 26.39% to 7.18%). Overall, the with-benefits distribution is more concentrated at lower burden levels, indicating that CAP benefits substantially

mitigate both typical burdens and high-burden outliers, although a small number of customers still experience high gas burdens. These results are summarized in Table 2.

Figure 4: Gas Burden for UGI CAP-Enrolled Customers With and Without CAP Benefits

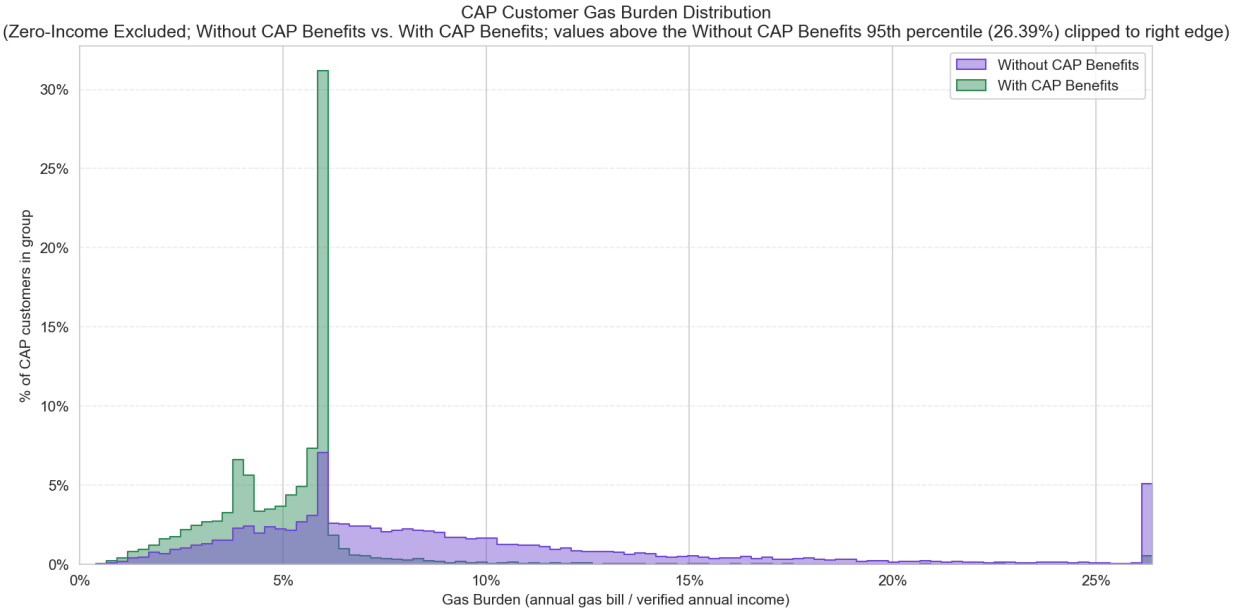


Table 2: Gas Burden for UGI CAP Enrolled (Gas Only Customers)

	Without CAP Benefits	With CAP Benefits
Number of Customers	**12,378**	**12,378**
Average	**13.02%**	**5.85%**
First Quartile - 25% of population	**5.48%**	**4.00%**
Second Quartile/Median – 50% of population	**7.60%**	**5.47%**
Third Quartile – 75 % of population	**11.43%**	**6.01%**
90% of population	**18.16%**	**6.09%**
95% of population	**26.39%**	**7.18%**
99% of population	**72.95%**	**16.81%**
Maximum	**10,179.83%**	**2,500.00%**

* Analysis excludes customers with less than 12 months of CAP bill data as well as those with zero-income.

Q. Did Atrium look at any other metrics in addition to gas burden?

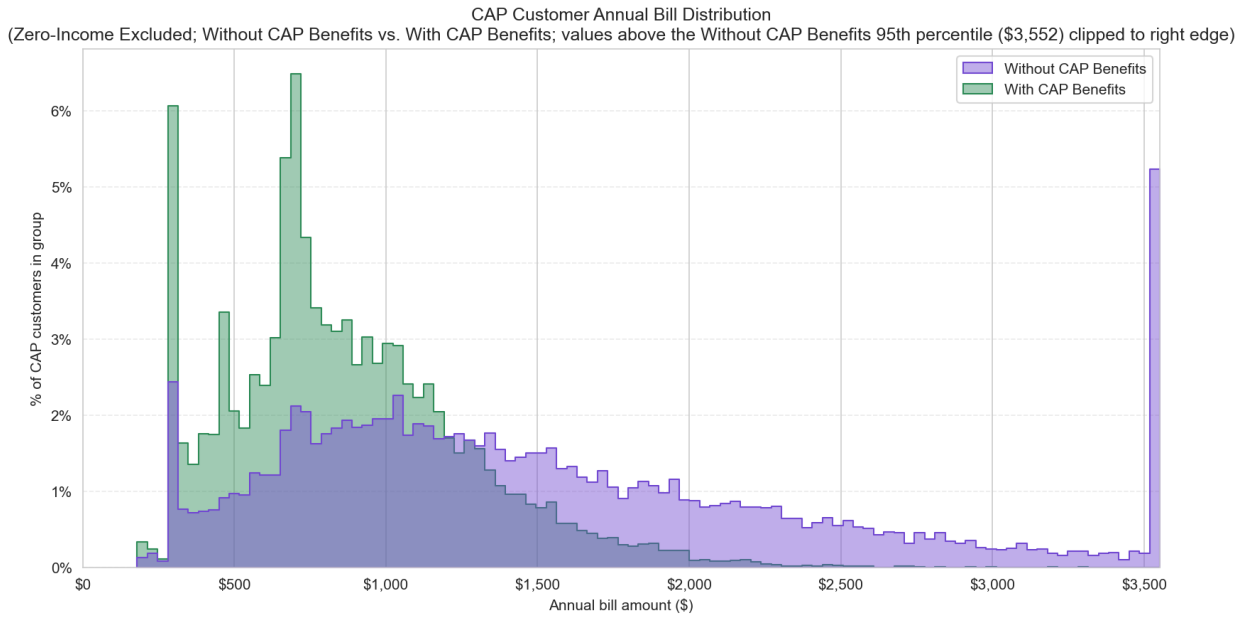
A. Yes. Atrium also evaluated annual gas bill amounts (in dollars) without and with CAP benefits—i.e., comparing each customer's estimated bill without CAP benefits (CAP bill plus CAP credit) to the CAP bill (with benefits)—to quantify the extent to which CAP benefits reduce customers' actual billed charges.

Q. Please summarize the results of that analysis.

A. Figure 5 summarizes Atrium's analysis of annual billed amounts for CAP-enrolled customers, comparing estimated without benefits annual bills (CAP bill plus CAP credit) to with benefits annual bills (CAP bill). Figure 5 shows that CAP benefits substantially

reduce annual bills: the median annual bill declines from approximately $1,341 pre-benefits to $807 post-benefits (a reduction of approximately 40%), and the mean annual bill declines from approximately $1,623 to $874 (a reduction of approximately 46%).

Figure 5: Annual Gas Bills for UGI CAP Enrolled Customers with and without CAP Benefits – excluding zero income



III. ROLE OF UTILITY ASSISTANCE PROGRAMS

Q. Please describe the customer assistance tools UGI Gas currently offers to help mitigate affordability concerns for residential customers.

A. UGI Gas offers and actively supports a comprehensive suite of assistance programs designed to address both short-term bill payment challenges and longer-term affordability issues, as discussed by UGI Gas Witness Meilinger (UGI Gas Statement Nos. 12 and 12-

R). These tools include federal and state programs, utility-administered assistance, community-based grants, usage reduction initiatives, and flexible payment options. Together, these programs reflect a broad approach intended to assist customers with varying financial circumstances, consistent with Pennsylvania's policy framework.

Q. At a high level, how can UGI's customer assistance tools be grouped by the type of need they address?

A. At a high level, these tools generally fall into three categories: (i) bill-payment assistance for customers facing financial hardship; (ii) usage-reduction offerings intended to lower bills over time by lowering consumption; and (iii) bill-stabilization and payment-flexibility options that help customers manage seasonal volatility and cash-flow constraints. Program-specific details, eligibility, and performance are addressed elsewhere in this proceeding, including in the direct and rebuttal testimony of UGI Gas Witness Meilinger.

Q. At a high level, how do these tools differ in purpose and funding?

A. These tools serve different functions and rely on different funding sources. Some bill-payment assistance is supported through federal or state programs that provide grants to eligible households. Other components—particularly the Company's Commission-approved Universal Service Programs, including ratepayer-funded assistance and usage-reduction offerings—are supported through Commission-approved cost recovery and therefore reflect an explicit balancing of the interests of participating and non-participating customers. Still other resources rely on voluntary or community-based support. Regardless of funding source, the common objective is targeted relief for

customers with demonstrated need, coupled with tools that help reduce usage or stabilize payment obligations.

Q. What do the intervenor witnesses' affordability concerns indicate, even with these tools in place?

A. The intervenors' testimony reflects that many households are experiencing real financial strain, and that even modest bill increases or seasonal bill changes can be difficult to manage for customers with limited income or limited savings. Utility-administered assistance programs can provide meaningful, targeted relief to eligible customers and are an important part of the Commission's affordability framework. At the same time, those tools are necessarily targeted and cannot, by themselves, resolve affordability challenges that are driven by broader income constraints and economywide cost pressures. Accordingly, these concerns support continued focus on the effectiveness, accessibility, and coordination of the Commission's universal service programs for customers most in need, while broader affordability pressures are addressed through broader state and federal economic and social policy tools outside of base ratemaking.

Q. What do you believe is the appropriate role of a regulated utility in addressing customer affordability concerns?

A. Utilities have a critical but inherently limited role in addressing affordability. UGI's responsibility is to provide safe and reliable service at rates that reflect prudent costs and comply with statutory ratemaking principles, while also implementing customer assistance programs. These programs can help mitigate bill impacts for income-eligible customers,

but they cannot fully resolve affordability challenges that are driven by income disparities and broader economic forces. Assigning utilities undue responsibility for addressing income-based affordability issues extends beyond traditional ratemaking objectives and is not an effective substitute for broader public policy solutions.

Q. How would you summarize the Company's overall approach to affordability while continuing to maintain a safe and reliable system?

A. UGI Gas's approach to affordability is responsible, comprehensive, and balanced. The Company actively administers and supports a wide range of assistance programs, invests in long-term usage reduction for income-eligible customers, and provides flexible payment tools for customers facing hardship. At the same time, UGI Gas continues to make the prudent investments necessary to ensure the safety and reliability of its system. Further, as described by Witness Rogers, the Company's expense history shows careful management of operating costs. This approach reflects the fundamental ratemaking principle that just and reasonable rates must support both customer protection and the operational integrity of the utility. The Company's proposed rates are consistent with that principle.

IV. PROGRAM ENROLLMENT AND DESIGN

Q. CAUSE-PA Witness Cicero and OCA Witness Colton both raise concerns about enrollment in assistance programs.[9] How should the Commission interpret that testimony?

[9] CAUSE-PA St. No. 1, pp. 70-72; OCA St. 6, pp. 53, 80.

A. The testimony of both witnesses highlights that program effectiveness depends on participation, and that enrollment outcomes are shaped by a variety of factors such as eligibility screening, documentation requirements, recertification processes, customer awareness, and coordination across assistance programs. As Mr. Colton explains, participation barriers can materially limit affordability outcomes even where assistance programs exist, and Mr. Cicero similarly points to customers who remain unenrolled and exposed to payment difficulty. Read together, their testimony supports the conclusion that enrollment challenges are programmatic and structural in nature, not evidence that current rates are unjust or unreasonable. These concerns indicate the need for a broader examination of assistance program design and administration, which is more appropriately addressed through universal service program review, rather than through base rate determinations focused on the recovery of prudent costs necessary to provide safe and reliable service.

Q. CAUSE-PA witness Patrick Cicero contends that low participation in assistance programs demonstrates that many customers remain exposed to unaffordable bills.[10] How do you respond?

A. I agree that enrollment gaps exist and that not all customers who may benefit from assistance programs are currently participating. However, enrollment gaps do not demonstrate that the Company's proposed rates are unjust or unreasonable. Rather, they indicate the need for a broader examination of program design, outreach, and coordination, including how customers are identified, informed, and supported through the enrollment

[10] CAUSE-PA St. No. 1, pp. 26-27.

process. These issues are distinct from the prudence of the Company's costs and the determination of its revenue requirement in this proceeding. The Company's ongoing efforts to address these enrollment gaps are detailed by UGI Gas Witness Meilinger (UGI Gas Statement No. 12-R).

Q. In your view, what is the appropriate role of this proceeding with respect to assistance program enrollment concerns?

A. The appropriate role of this proceeding is to determine whether the Company's proposed rates reflect prudent costs necessary to provide safe and reliable service. Concerns about enrollment levels and program design are important and warrant attention, but they point to the need for coordinated, system-level improvements in assistance programs, in proceedings designed to address those programs, rather than base rate case outcomes that deny or constrain cost recovery. Recognizing enrollment gaps as a signal for program evaluation preserves the integrity of ratemaking while allowing affordability issues to be addressed through the most effective regulatory tools.

Q. Even if the Commission revises or expands UGI Gas's independent utility assistance programs, can utility programs—or utility ratemaking itself—serve as a solution to broader macroeconomic affordability challenges?

A. No. Utility assistance programs can provide important, targeted relief for income-eligible customers and can be improved over time through program design, outreach, and administration. However, neither utility programs nor cost-based ratemaking are designed to resolve the underlying drivers of economywide affordability pressures, such as inflation,

housing costs, or healthcare expenses. Attempting to use utility rates to address those broader conditions would dilute core ratemaking principles, create inequitable cross-subsidies among customers, and introduce additional regulatory uncertainty. For these reasons, even with revisions to independent utility programs, the appropriate role of this proceeding remains to set just and reasonable rates based on the prudent cost of providing safe and reliable service, while broader macroeconomic affordability issues are more appropriately addressed through state and federal public policy tools that extend beyond utility regulation.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

UGI Gas Exhibit CSF-1R

Cyndee Fang

Ms. Fang is an experienced industry leader with over 20 years of experience who strives to engage others to conceive, create, and execute practical solutions to the most challenging problems. Expert witness with extensive experience and understanding of utility regulatory process including expertise in regulatory strategy and rate design.

EDUCATION

University of Minnesota, Ph.D. (ABD), Applied Economics

University of California, Berkeley, B.S., Political Economics of Natural Resources

YEARS EXPERIENCE

20+

RELEVANT EXPERTISE

Expert Witness, Allocated Cost of Service & Rate Design, Regulatory Strategy

PROFESSIONAL HISTORY

ATRIUM ECONOMICS

DIRECTOR, 2024

- Expert witness focused on the following areas of expertise:
    - Regulatory Policy & Strategy;
    - Cost Recovery & Alternative Regulatory Mechanisms;
    - Allocated Cost of Service Studies; and
    - Rate Design.

NORTHWESTERN ENERGY

VICE PRESIDENT - REGULATORY; 2021 - 2024

- Oversaw the Company's regulatory activities in Montana, South Dakota, and Nebraska.
- Developed and executed a regulatory strategy to advance a more constructive regulatory framework to meet the Company's strategic needs.
- Established an in-house cost of service and rate design team.
- Developed and executed a strategy for Montana rate reviews to advance a more constructive regulatory framework.

SAN DIEGO GAS AND ELECTRIC

ENERGY SUPPLY - ORIGINATION & PORTFOLIO DESIGN MANAGER; 2020 – 2021

- Lead the portfolio design of Electric & Fuel Procurement (E&FP), as SDG&E right-sizes portfolio, with market analytics that inform and guide the long-term strategy including daily optimization activities and forward-looking planning efforts.
- Lead all competitive procurement of renewable energy and conventional resources beyond one year to fulfill SDG&E's energy and resource capacity needs.

FORECASTING, RESEARCH & ANALYTICS – MANAGER OF ENERGY RESEARCH & ANALYSIS; 2018 – 2020

- Lead and oversee load forecasting, research and analysis teams to ensure the advancement of data-driven decision making in support of the Company's strategic needs including the advancement of operational improvements to better address changing California energy policies. Key areas of focus include impacts of customer adoption of advanced technology (PV, EV) and analysis of COVID impacts.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric sales forecast. Key areas of focus include identification of key drivers and CCA expansion.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company's strategic objectives related to the sales forecast.

RATES AND PRICING – MANAGER OF CUSTOMER PRICING; 2017 – 2018

- Oversight of all aspects of the pricing policy to meet the strategic needs of SDG&E and ensure fair and equitable rates for SDG&E's 1.4 million electric customers.
- Development, advocacy and implementation of the Company's rate strategy, including the development of regulatory filings to advance this strategy.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric rates.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company's rate strategy needs to include representing the Company as a witness in regulatory proceedings and lead settlement negotiations.

RATE STRATEGY AND ANALYSIS MANAGER; 2015 – 2017
ELECTRIC RATES MANAGER; 2010 – 2015
PRINCIPAL/REGULATORY ECONOMIC ADVISOR; 2006 - 2010

MINNESOTA DEPARTMENT OF COMMERCE

PUBLIC UTILITIES RATES ANALYST; 2003 - 2006

- Development of the position of the Minnesota Department of Commerce on matters related to energy policy and presentation before the Minnesota Public Utilities Commission
- Implementation of Minnesota's Renewable Energy Objective, including the establishment of the Minnesota Renewable Energy Tracking System and compliance review of utility filings (integrated resource plans, certificate of need)

REGULATORY EXPERIENCE

Alternative Regulatory Mechanisms

- Consideration of the Formula Rate Mechanism Tariff Revision Designated as TA 353-4 *on behalf of ENSTAR Natural Gas Company, LLC of Alaska* (Docket No. U-25-013). Filed April 2025.
- 2022 Montana Rate Review (Docket No. 2022.07.078) - Witness: Priority Regulatory Mechanisms proposing new revenue adjustment mechanisms and redesign of existing mechanisms https://www.northwesternenergy.com/docs/default- source/default-document-library/billing-and-payment/2022-montana-rate-review/08-fang- direct-testimony-regulatory-policy.pdf
- PCIA Reform (A.17-04-018) - Joint Application of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company for Approval of the Portfolio Allocation Methodology for All Customers – *Cost Recovery and Rate Design witness for SDG&E*
- Establishment of Tree Mortality Non-Bypassable Charge (TM-NBC) (A.16-11-005) Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805 – *Cost Recovery and Rate Design witness for SDG&E*
- SDG&E's Wildfire Expense Memorandum Account (WEMA) Proceeding (A.15-09-010) – *Cost Recovery witness*
- Establishment of Cost Allocation Mechanism (CAM) (A.11-05-023) - SDG&E's Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power – *Cost Recovery and Rate Design witness*

Affordability

- Affordability Rulemaking – R.18-07-006: Order Instituting Rulemaking to Establish A Framework and Processes for Assessing the Affordability of Utility Service – *SDG&E lead*
- Residential Essential Use Study – A.19-11-019: Joint Utility Proposal for the Study to Identify Electric Essential Usage for Residential Customers – *SDG&E lead*
- A.17-10-007: SDG&E 2019 General Rate Case – *rebuttal witness addressing affordability*
- Residential TOU Exclusions Pursuant to Section 745 – R.12-06-013: To ensure residential customers defaulting to TOU do not experience unreasonable hardship under TOU rates – *Rate Design Policy witness*

Allocated Cost of Service and Rate Design

- Washington Gas Light Company's Application for Authority to Increase Rates and Charges for Natural Gas (Case No. 9849) – Witness: Class Cost of Service Studies, Revenue Apportionment, and Rate Design. Filed December 2025.

- 2022 Montana Rate Review (Docket No. 2022.07.078) - Witness: Allocated Cost of Service and Rate Design presenting the Company's moderation proposals to allocated cost of service and rate design for customers https://www.northwesternenergy.com/docs/default-source/default-document-library/billing- and-payment/2022-montana-rate-review/31-fang-acos-rd-direct-testimony.pdf
- SDG&E General Rate Case Phase 2 Application for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design - *Rate Design and Policy Witness*

Rate Design

Time-Variant Pricing and Residential Default Time-of-Use

- The Narragansett Electric Company d/b/a Rhode Island Energy Application for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I. Gen. Laws §§39-3-10 and 39-3-11 (Docket No. 25-45-GE) – Witness: presenting the Company's framework for development of time-varying rates ("TVR") and a TVR implementation plan. Filed November 2025.
- Petition for Approval of (1) Time of Use ("TOU") and Critical Peak Pricing ("CPP") Rates and (2) Modification of the TOU Summer Period for the CPP Pilot Program, and (3) CEI South's Rate RS-CPP Tariff *on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South* (Cause No. 46263) Filed June 2025.
- Application of San Diego Gas & Electric Company for Authority to Update Electric Rate Design Regarding Residential Default Time-Of-Use Rates and Fixed Charges (A.17-12-013)
- Residential Rate Reform (R.12-06-013) - SDG&E's Application in response to Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations – *multiple phases*
- SDG&E's 2016 General Rate Case Phase 2 Proceeding (A.15-04-012) - includes proposal to update TOU periods
- SDG&E's 2015 Rate Design Window Filing (A.14-01-027) – includes proposal to update TOU periods and residential baseline

Innovative Rate Design and Emerging Technologies

- SDG&E's Electric Vehicle Grid Integration (VGI) Pilot Program (A.14-04-014) – *Rate Design Policy and Cost Recovery witness*
    - SDG&E was recognized as the 2020 Investor-Owned Utility of the Year by Smart Electric Power Alliance (SEPA) for its "Power Your Drive" program and the innovative VGI rate, an hourly dynamic grid integrated rate. https://sepapower.org/knowledge/2020-sepa-power-players- award-winners/
- Net Energy Metering Reform (R.14-07-002) - SDG&E Application in response to Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering

- Application of SDG&E for Authority to Implement Priority Review and Standard Review Proposals to Accelerate Widespread Transportation Electrification (A.17-01-020) – *Rate Design Policy and Cost Recovery witness*

Economic Development Rates

- Application of San Diego Gas & Electric Company for Authority to Implement Rate Relief and Increase Spend in Support of the San Diego Unified Port District's Energy Management Plan (A.17-09-005) – *Cost Recovery and Rate Design witness*
- Application of SDG&E for Authority to Implement Economic Development Rates (A.17-02-008) – *Cost Recovery and Rate Design witness*

Cost Recovery

- Assessment of Potential Gas LDC Capital Transition Costs and Analysis of Depreciation and Alternative Cost Recovery Approaches for Pathways to Commonwealth Decarbonization Goals *on behalf of Massachusetts Gas Local Distribution Companies (National Grid; Eversource Energy; Berkshire Gas Company; Liberty Utilities; Unitil)* Filed March 2025.
- Strategic Targeted Pipe Replacement Plan *on behalf of Washington Gas and Light Company of the District of Columbia* (Formal Case No. 1179) – rebuttal witness: responding to parties on risk of stranded assets and stranded costs. Filed January 2025.
- SONGS Decommissioning (A.14-12-007) Joint Application of SDG&E and SCE for 2014 SONGS Units 2 & 3 Decommissioning Cost Estimate and related Decommissioning – *Cost Recovery witness*
- SDG&E General Rate Case Application for Authority to Update its Electric and Gas Revenue Requirements and Base Rates - *Cost Recovery and Rate Design witness; multiple years*
- ERRA Trigger (A.17-05-012) Expedited Application of San Diego Gas & Electric Under the Energy Resource Recovery Account Trigger Mechanism
- SDG&E's Energy Resource Recovery Account (ERRA) Forecast Application for the recovery of costs associated with electric procurement – *Cost Recovery and Rate Design witness, multiple years*

SELECTED PUBLICATIONS / PRESENTATIONS

Panelist at Critical Consumer Issue Forum (CCIF)

- Critical Consumer Issues Forum (CCIF) 14th Annual Kickoff Forum in Collaboration at 2023 NARUC Annual Meeting; Topic: "Exploring Rate Design & Other Regulatory Tools: Maximizing Grid Value & the Customer Experience."
- "Navigating the Challenges & Opportunities of Today's Regulatory Landscape" https://criticalconsumerissuesforum.com/wp-content/uploads/CCIF-2023-Navigating-Regulatory- Landscape-Report.pdf
- "The Customer-Centered Clean Energy Transition: Balancing Technology, People & the Planet"

Presenter/Instructor ad EEI Advanced Rate School at University of Wisconsin Public Utility Institute (WPUI); July 2021.

Advanced Workshop in Regulation and Competition – Annual Western Conference held by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University

- "Zen and the Art of Rate Design" – Webinar sponsored by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University, January 13, 2021 – Link to webinar Zen and the Art of Rate Design [nam02.safelinks.protection.outlook.com]
- Member of Western Conference Organizing Committee from 2015-2022.
- Author/Co-author and Presenter as well as chair/discussant – multiple years.
    - 2022 – "Residential Time of Use Rates…and how one utility got there"
    - 2019 – "A Modern Rate Architecture for California's Future"
    - 2017 – "Solar Adoption and Customer Consumption in the Residential Sector"
    - 2016 – "Solar Adoption and Customer Demand in the Residential Sector"
    - 2014 - "Revisiting Rate Structure Reform to Meet a Low Carbon Future"
    - 2013 - "Unbundling – A Needed Fix for Residential Rate Design"
    - 2012 - "Rate Structure Reform to Meet a Low Carbon Future"

"Residential Time of Use…and what it took to get there" Presentation at EPRI's Rates Working Group (September 2020)

Discussant for 2020 POWER Conference– Session: Retail Rate Design (April-May 2020, Energy Institute at Haas School of Business, University of California, Berkeley) - Link to 2020 POWER Conference https://haas.berkeley.edu/energy-institute/events/power-conference/past-power-conferences/2020- power-conference/

Panelist at CEC Workshop on Scope of Load Management Rulemaking (January 2020) - Link to workshop https://www.energy.ca.gov/event/workshop/2020-01/commissioner-workshop-scope-load-management-rulemaking-19-oir-01

Presentation at Advanced Rate Design Strategy Workshop hosted by Hawaiian Electric (July 2019) - Link to workshop https://www.hawaiianelectric.com/clean-energy-hawaii/grid-modernization- technologies/advanced-rate-design-strategy

Panelist at Forth Roadmap Conference 2019 – Session: Rate Design to Accelerate Transportation Electrification (June 2019) - Link to Roadmap 12 http://roadmapforth.org/program/

"A Modern Rate Architecture for California's Future" by Margot Everett (PG&E), Cynthia Fang (SDG&E), Andre Ramirez (SCE), and Jude Schneider (SCE); Public Utilities Fortnightly, Vol 156, No. 12; November 1, 2018.

"SDG&E's Design of Grid Integrated Rates" at Panelist at CEC Workshop: CA Vehicle-Grid Integration Roadmap (October 2018) - Link to workshop information https://www.energy.ca.gov/programs-and- topics/programs/california-vehicle-grid-integration-roadmap-update/past-workshops-and

Panelist at CPUC ZEV Rate Design Forum 2018: California Public Utilities Commission forum to review and evaluate electric rate designs that could support the state's zero-emission vehicle goals established by Governor Jerry Brown's executive order B-48-18: having 5 million light-duty zero-emissions vehicles on the road by 2030. (June 2018) - Link to CPUC ZEV Rate Design Forum 2018 https://www.cpuc.ca.gov/energy/electricrates/

Panelist at CPUC Rate Design Forum on Demand Charges and Advanced Rate Designs (December 2017) - Link to CPUC Electric Rate Forum 2017 https://www.cpuc.ca.gov/General.aspx?id=6442455548

Presentations at Utility of the Future Rate Group sponsored by Economics Incorporated

- "COVID 19 Impacts – Some Early Insights" (May 2020)
- "A Customer-Focused Alternative to Pricing" (November 2019)
- "SDG&E's Design of Real Time Pricing and Other Dynamic Rates" (April 2017)

PUBLIC VERSION

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 2-RJ

Rejoinder Testimony of
Tracy A. Hazenstab

Topics Addressed: **Revenue Requirement**

Dated: June 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 2, on January 28, 2026, and Public and CONFIDENTIAL versions of my rebuttal testimony, UGI Gas Statement No. 2-R on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony provides updates to certain components of the Company's filing.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, I am sponsoring the Company's Accounting Exhibit UGI Gas Exhibit A – Fully Projected (REJOINDER), which reflects all of the updates to the Company's claim identified to date.

II. REVENUE REQUIREMENT

Q. Since the filing of your rebuttal testimony, has the Company identified any components of its filing that should be updated?

A. Yes, in order to limit the issues around the Company's revenue requirement claim for the FPFTY in this proceeding, the Company is withdrawing the following items from its revenue requirement calculation:

- Incentive Compensation: As noted above and explained further in the rejoinder testimony of Vivian K. Ressler (UGI Gas Statement No. 4-RJ), the Company is withdrawing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from its claim related to incentive compensation. This adjustment is reflected in Line 19, Administrative & General Expense, on Schedule D-2 and decreases the revenue requirement by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** after cash working capital calculations.
- Employee Activity Expense: As noted above and explained further in the rejoinder testimony of Vivian K. Ressler (UGI Gas Statement No. 4-RJ), the Company is withdrawing ($195,000) from its claim related to employee activities. This adjustment is reflected in Line 19, Administrative & General Expense, on Schedule D-2 and decreases the revenue requirement by ($197,000) after cash working capital calculations.
- Sponsorship of Community Events: As noted above and explained further in the rejoinder testimony of Vivian K. Ressler (UGI Gas Statement No. 4-RJ), the Company is withdrawing ($191,149) from its claim related to sponsorship of community events. This adjustment is reflected in Line 18, Sales Expense, on Schedule D-2 and decreases the revenue requirement by ($197,000) after cash working capital calculations.

Q. Based upon the adjustment analyses conducted by the Company, what do you conclude?

A. As set forth in UGI Gas Exhibit A – Fully Projected (REJOINDER), the overall effect of these changes is a decrease in the Company's fully projected future test year ("FPFTY")

revenue increase from $98.693 million, as stated in my rebuttal testimony, to $91.438 million, using the Company's proposed capital structure and return on equity of 10.75%.[1]

III. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

[1] This amount does not include the additional dedicated low-income program advertising campaign proposed in the rejoinder testimony of UGI Gas Witness Brian J. Meilinger, UGI Gas Statement No. 12-RJ, which would be additive to the revenue requirement but within the originally filed request of $99.4 million.

PUBLIC VERSION – CONFIDENTIAL MATERIAL REDACTED

V

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 4-RJ

Rejoinder Testimony of
Vivian K. Ressler

Topics Addressed:
Incentive Compensation Expense
Employee Activities Expense
Advertising Expense
PUC Assessment

Dated: June 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 4, on January 28, 2026. I also submitted rebuttal testimony on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. The purpose of my rejoinder is to respond certain portions of the following surrebuttal testimony submitted by the Pennsylvania Public Utility Commission's ("Commission" or "PUC") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1-SR, the surrebuttal testimony of Zachari Walker; and OCA Statement 2SR, the surrebuttal testimony of Jennifer L. Rogers. More specifically, I provide the Company's final position for purposes of adjustments proposed by these witnesses to various of the Company's operations and maintenance ("O&M") expenses. Unless otherwise specifically indicated, the Company maintains its rebuttal position with respect to the other parties' proposals to disallow portions of its O&M expense claims.

II. REJOINDER REGARDING INCENTIVE COMPENSATION

Q. Did any of the other parties submit surrebuttal testimony regarding the Company's claim for incentive compensation expense?

A. Yes. Both I&E Witness Walker and OCA Witness Rogers submitted surrebuttal testimony to address these issues. I&E St. No. 1-SR, at pp. 21-24; OCA St. 2SR, at pp. 5-10. In summary, both I&E and OCA stand by the positions they took in direct testimony, which recommend a disallowance of a portion of the Company's claim to recover the costs of various incentive compensation plans as a part of the revenue requirement proposed in this case.

Q. What is the Company's response to the surrebuttal testimony offered by I&E and OCA?

A. For the reasons explained in my direct testimony, the Company continues to believe that the incentive compensation costs it anticipates to incur during the fully projected future test year ending September 30, 2027 (the "FPFTY") in this matter represents a reasonable and prudently incurred cost that is an important and necessary component of the overall compensation of employees, managers, and executives that have responsibility for the Company's operations and its provision of safe and reliable natural gas service to its customers. Critically, neither I&E nor OCA claims that any compensation related expenses included in the Company's claim are imprudent or excessive, let alone that the specific amounts related to this one subcategory of incentive compensation are imprudent or excessive.

While both I&E Witness Walker and OCA Witness Rogers attempt to characterize their proposals as targeted to specific elements of these costs that lack a "ratepayer benefit,"

neither of these witnesses directly responds to my rebuttal testimony which explained generally and specifically how the components of the Company's incentive compensation plans targeted for disallowance by I&E and OCA do, in fact, directly benefit ratepayers. *See* UGI Gas St. No. 4-R, at pp. 5-9.

Most specifically, I note that, among other items, I&E targeted for disallowance portions of the Company's Management Incentive Plan related to Capital Investment and Capital Placed-in-Service goals as a "financial performance metric" that only benefits shareholders. I&E St. No. 1-SR, at pp. 22-23. However, these metrics drive physical infrastructure modernization that produces a safer, more reliable system for ratepayers. And, critically, neither I&E nor any other party to this proceeding has testified that (1) UGI Gas's capital investments are imprudent or unnecessary or (2) proposed to disallow any portion of the Company's capital investments. Execution on UGI Gas's capital investment plans and strategy do have a direct and material benefit to customers, which is evidenced by the parties' decisions not to target any of the Company's projected capital work for disallowance in this case.

Q. Does the Company continue to disagree with the adjustments proposed by I&E and OCA related to its incentive compensation costs?

A. Yes, it does.

Q. In order to limit the disputes regarding the Company's revenue requirement claim for the FPFTY in this proceeding, is the Company willing to voluntarily update its position regarding incentive compensation expense?

A. Yes. I want to emphasize that the Company's incentive compensation plan costs are reasonable and should be approved. However, in order to limit the number of disputed issues in this proceeding, the Company will voluntarily withdraw the incentive compensation costs that are the subject of OCA Witness Rogers' proposed adjustment in this proceeding. The impact of this decision is to decrease the Company's revenue requirement claim by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This decrease is reflected in the Company's final revenue requirement model sponsored by UGI Gas Witness Hazenstab (UGI Gas St. No. 2-RJ and UGI Gas Exhibit A – Fully Projected (REJOINDER)).

III. REJOINDER REGARDING EMPLOYEE ACTIVITIES EXPENSE

Q. Did any of the other parties submit surrebuttal testimony regarding the Company's claim to recover certain employee activities expenses?

A. Yes. Both I&E Witness Walker and OCA Witness Rogers submitted surrebuttal testimony to address these expenses. In summary, I&E maintains its direct testimony position and continues to assert that employee activities costs associated with the Company's picnic are not appropriately recoverable in rates. I&E St. No. 1-SR, at pp. 15-17. OCA updates its position and now only proposes to disallow the costs associated with the Company's picnic. OCA St. 2SR, at p. 11.

Q. What is the Company's response to I&E's and OCA's positions regarding employee activities expenses in surrebuttal testimony?

A. While the Company continues to believe that it is appropriate to recover the costs of this specific employee activity under past Commission precedent and as an important component of how it recognizes and motivates its employees, the Company will voluntarily withdraw is request to recover the costs of the Company picnic in order to limit the number of disputed issues in this proceeding. The impact of this decision is to decrease the Company's revenue requirement claim by $195,000. This decrease is reflected in the Company's final revenue requirement model sponsored by UGI Gas Witness Hazenstab (UGI Gas St. No. 2-RJ and UGI Gas Exhibit A – Fully Projected (REJOINDER)).

IV. REJOINDER REGARDING ADVERTISING EXPENSES

Q. Did any of the other parties submit surrebuttal testimony regarding the Company's claim to recover community event sponsorship advertising expenses?

A. Yes. Both I&E Witness Walker and OCA Witness Rogers submitted surrebuttal testimony to address community event sponsorship advertising expenses. In summary, both I&E and OCA maintain their direct testimony positions and continue to assert that these advertising costs are not appropriate for recovery within rates. I&E St. No. 1-SR, at pp. 11-15; OCA St. 2SR, at pp. 13-14.

Q. What is the Company's response?

A. While the Company continues to believe that it is appropriate to recover the costs of this specific advertising expense, the Company will voluntarily withdraw its request to recover the costs of community event sponsorship advertising expenses in order to limit the number

of disputed issues in this proceeding. The impact of this decision is to decrease the Company's revenue requirement claim by $191,000. This decrease is reflected in the Company's final revenue requirement model sponsored by UGI Gas Witness Hazenstab (UGI Gas St. No. 2-RJ and UGI Gas Exhibit A – Fully Projected (REJOINDER)).

V. REJOINDER REGARDING PUC ASSESSMENT EXPENSE

Q. Did any of the other parties submit surrebuttal testimony regarding the Company's claim to recover certain advertising expenses?

A. Yes. OCA Witness Rogers continues to recommend that the Company's claim be reduced by $1.8 million to reflect the use of a three-year average to calculate this expense. OCA St. 2SR, at pp. 17-18.

Q. What is the Company's response to OCA Witness Rogers's surrebuttal regarding this issue?

A. While OCA attempts to assert that this expense category is "volatile," OCA Witness Rogers simply ignores that the trend for this expense is a significant increase whether or not one looks back six years or three years. Moreover, OCA Witness Rogers ignores that the Company's method was both (1) more accurate at predicting the most recent actual expenses incurred by the Company and (2) still resulted in an understatement of this cost. The Company's method of estimating this expense is reasonable and conservative.

Finally, I note that OCA Witness Rogers testifies that "a fundamental principle of ratemaking is that costs should be assigned to those who benefit from them." OCA St. 2SR, at p. 10. My understanding of these costs is that they fund the Commission's

operations, as well as the operations of both OCA and OSBA. Her proposed adjustment related to the PUC Assessment expense appears inconsistent with this testimony.

VI. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3059523, et al.
UGI Utilities, Inc. – Gas Division	)	

UGI GAS STATEMENT No. 6-RJ

REJOINDER TESTIMONY OF
JOHN F. WIEDMAYER
ON BEHALF OF
UGI UTILITIES, INC. – GAS DIVISION

June 1, 2026

REJOINDER TESTIMONY OF JOHN F. WIEDMAYER
GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
ON BEHALF OF UGI UTILITIES, INC. – GAS DIVISION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. ARE YOU THE SAME JOHN WIEDMAYER THAT PRESENTED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. The purpose of my rejoinder testimony is to respond to the arguments and positions presented by Office of Consumer Advocate ("OCA") Witness James Garren in his surrebuttal testimony concerning the depreciation methodologies, specifically the appropriateness of continuing the longstanding practice of using the Equal Life Group ("ELG") procedure rather than the Average Life Group ("ALG") procedure for UGI Utilities, Inc. ("UGI Gas" or "Company"). Mr. Garren also proposes alternative survivor curve estimates for Account 375, Structures and Improvements; Account 376.1, Mains - Primarily steel; and Account 378, Measuring and Regulating Station Equipment- General. My testimony will respond to these positions and provide a detailed rebuttal supported by evidence and reasoning that underscores the advantages and correctness of the ELG method in this context.

Q. PLEASE PROVIDE A SUMMARY OF THE KEY ELEMENTS OF YOUR REJOINDER TESTIMONY.

A. First, I address Mr. Garren's claim that my arguments regarding ELG are invalid because I propose ALG in other jurisdictions. Additionally, I describe recent cases in other jurisdictions considering moving to ELG, in part due to significant technological, environmental and regulatory changes underway. I also provide context of Pennsylvania's depreciation practice and explain that the deferral of the recovery of future net salvage (primarily cost of removal) means that Pennsylvania utilities are behind in the recovery of capital costs relative to other jurisdictions. I then refute claims that ELG causes intergenerational inequity and Mr. Garren's inaccurate allegations that ELG is harmful to current customers, emphasizing that the goal is to match the recovery of capital costs with the decrease in the utility assets' service potential. Third, I address Mr. Garren's claims regarding the history and precedent for ELG in Pennsylvania. Fourth, I address Mr. Garren's claims about UGI Gas's implementation of rates, explaining that the ELG depreciation rates are generally stable from year to year and his concerns of the need for annual updates are unfounded and addressed by the PA PUC's regulations regarding depreciation practices. In conclusion, ELG remains the most precise and fair depreciation method for UGI Gas, ensuring accurate cost recovery and aligning with long-term customer interests.

II. EQUAL LIFE GROUP VS AVERAGE LIFE GROUP

Q. PLEASE DISCUSS MR. GARREN'S CLAIMS REGARDING GANNETT FLEMING'S USE OF THE ALG PROCEDURE IN OTHER JURISDICTIONS.

A. Mr. Garren argues that the use of ALG in other jurisdictions essentially means that ELG should no longer be used in Pennsylvania even though UGI Gas has used the ELG

procedure for 44 years.[1] While it is true that ALG is a commonly used depreciation procedure used in other state jurisdictions, that is not the in case in Pennsylvania. Nearly all of the major investor-owned gas utilities in Pennsylvania use the ELG procedure. A majority of the major water and electric companies, including UGI Electric, also use the ELG procedure. Accepting the OCA's recommendation to reverse the long-standing depreciation calculation procedure from ELG to ALG for UGI Gas, while nearly all other gas companies in Pennsylvania use the ELG procedure, is unreasonable and unfair as a ratemaking policy decision.

Q. ON PAGE 4 OF MR. GARREN'S SURREBUTTAL TESTIMONY HE STATES, "THE ELG PROCEDURE DOES HAVE THE BENEFIT OF BEING A THEORETICALLY SUPERIOR PROCEDURE FOR ALLOCATING THE COST OF PLANT INVESTMENT, BECAUSE IT TRACKS THE RETIREMENT PATTERNS." DO YOU AGREE?

A. Yes, I agree with Mr. Garren. This is an indisputable fact. In addition to Mr. Garren's statement, Robley Winfrey, a professor at Iowa State University who developed the Iowa Type Survivor Curves in the 1930s and was a pioneer in the field of Engineering Valuation called the ELG procedure, "the only mathematically correct procedure". Mr. Garren also acknowledges "that the ELG method is more precise (than ALG), for a given life and retirement curve" and that Figure 2 of my rebuttal testimony, which presents the retirement frequency curve for Account 380, Services, "correctly projects the expected life of a single vintage over time".

[1] OCA St. 4SR, at pp. 7-8.

Q. ON PAGE 5 OF MR. GARREN'S SURREBUTTAL TESTIMONY HE STATES, "WHILE ELG IS PRECISE, THAT PRECISION IS HARMFUL IF OUR ESTIMATES CHANGE OVER TIME." DO YOU AGREE?

A. First, it is not clear what is harmful when estimates change. Presumably, Mr. Garren believes that since ELG results in an accelerated rate of depreciation early in the assets' lives relative to the ALG procedure that current customers are paying higher rates effectively subsidizing future customers. To this notion I do not agree that ELG effectively provides a subsidy to customers. Mr. Garren is incorrect. As I explained in my rebuttal testimony, ELG provides a more accurate recovery of costs, and this increased accuracy should not be characterized as accelerated depreciation. ELG is not an accelerated method; rather it is a straight line method. Capital recovery using ELG occurs ratably over the specific (i.e., not average) service life of the assets. The service lives for distribution plant assets, such as service lines, range from 1 year to 84 years using a 45-R2 survivor curve. One difference between the two depreciation procedures (i.e., ALG vs. ELG) is that ALG uses <u>one</u> average service life while ELG uses 84 different service lives based on the range of service lives contemplated by the survivor curve selected for Account 380, Services. ALG is most appropriately thought of as deferring the recovery of short-lived assets because it relies on the *average* service life of the assets. The shorter-lived assets are not fully recovered at the time of their retirement, and this under-recovery must be made up for by the over-recovery on longer-lived assets. However, care needs to be exercised when dealing with averages, as averages can mask important underlying information needed to make a proper evaluation. The phrase, "Beware of the *flaw* of averages" illuminates the

potential concealment of information and intermediate steps in the calculation caused by the use of averages, as does the following anecdote:

> The Susquehanna River at Harrisburg PA has an *average* depth of 3 feet during certain summer weeks but you would not want to attempt to walk across the river at those times if you did not know how to swim, as the depth of the main river channel is 10-12 feet deep.

Overreliance on averages can lead to unexpected and detrimental outcomes. The ALG procedure uses averages which are used, for calculation purposes, primarily as a matter of convenience. The use of averages often conceals detailed recovery patterns, which includes these depreciation-related deferrals and overcollections vis-à-vis the ELG procedure. The pattern of recovery for the ALG is typical when using averages in that it under-recovers on the short lived assets (i.e., assets that have shorter lives relative to the average life) but it over-recovers on the long-lived assets.

Q. WOULD CHANGING TO ALG RESULT IN A SUBSIDY FOR CURRENT CUSTOMERS?

A. Yes. A change to ALG for UGI Gas now would provide current customers with the benefit from the lower rate base due to the historical use of ELG, the deferral of recovery over average life and artificially low ALG rates for the near term due to the higher accumulated depreciation resulting from decades of using the ELG procedure. The change to ALG, as recommended by Mr. Garren, therefore produces a subsidy for current customers for roughly the next 10 to 15 years. After 10 years or so, there will be a crossover related to customer rates as ALG will result in higher customer rates based on the higher return on rate base impact compared with the lower annual depreciation expense impact.[2] Without

[2] *See* Exhibit No. JFW-R1 submitted with Mr. Wiedmayer's Rebuttal Testimony

using a complex model to demonstrate this calculation, it is reasonable to assess the accuracy of the prior statement by considering the overall rate of return proposed by the company in this proceeding is 8.22% while the composite gas plant depreciation rate including common plant and information services is 2.58%. Since the ~$21M depreciation expense reduction proposed by Mr. Garren will cause ~$21M increase in rate base in year 1, $42M in year 2 and $210M in year 10, obviously the rate of return impact will overtake the annual depreciation expense impact since the rate of return of 8.22% is significantly larger than the composite depreciation rate of 2.58%. In 1982, when ELG was initially used by UGI Gas, the overall rate of return was 13.42% and the composite depreciation rate was ~2.50% so the crossover would occur more rapidly, perhaps over 6-10 years rather than the 10-15 years based on the current spread. The spread between the two (i.e., ROR vs depreciation rate) has historically been much larger than it is today.

Q. HAVE OTHER JURISDICTIONS CONSIDERED ELG, PARTICULARLY IN THE CONTEXT OF TECHNOLOGICAL AND REGULATORY CHANGE IN THE ENERGY INDUSTRY?

A. Yes. Mr. Garren does not address these, but in my rebuttal testimony I discussed the use of ELG in Colorado and the proposed use in New York.[3] Because the ELG procedure better matches the recovery of shorter-lived assets in a property group, it is better suited and more equitable during times of technological change and regulatory uncertainty as well. Further, because Pennsylvania depreciation practices already incorporate a significant deferral of the recovery of net salvage, it would not be reasonable to move towards further deferring depreciation expense (and the associated higher costs to

[3] UGI Gas St. No. 4-R, at p. 16.

customers). In this regard, it is to be noted that net salvage is the difference between the cost of removal of retired plant and any salvage value, which is generally a net cost. Mr. Garren's proposal would move depreciation in the wrong direction at the worst time.

Q. PLEASE EXPLAIN HOW NET SALVAGE IS DEFERRED IN PENNSYLVANIA.

A. As a result of a 1962 Superior Court Decision,[4] Pennsylvania is one of the only states in the country that defers the recovery of net salvage until after the assets are retired. Industry standard depreciation practices (which Mr. Garren typically follows) are to estimate future net salvage and include these estimates in depreciation rates. This approach, referred to as the "Traditional Method" for net salvage, results in intergenerational equity because customers pay for net salvage costs over the life of property (*i.e.,* during the time they provide service to customers). Pennsylvania, in contrast, defers recovery related to negative net salvage until after the assets are retired, meaning that customers have to pay the costs of assets that no longer provide service.

Q. HOW DOES THE DEFERRAL OF THE RECOVERY OF NET SALVAGE IMPACT THE COMPANY'S DEPRECIATION RATES?

A. The Company's depreciation rates are too low to equitably recover the full service value of property.[5] Mr. Garren is aware of this since he includes future net salvage in his proposed depreciation rates for his clients in states other than Pennsylvania. The use of the ELG procedure helps mitigate these deferrals. Mr. Garren's proposal to move away from ELG would create further inequity and push a significant share of costs to future customers.

[4] *Penn Sheraton Hotel v. Pennsylvania Public Utility Commission*, 202 Pa. Super. 403, 195 A.2d 180 (Pa. Super. Ct. 1962).
[5] Service value is equal to the original cost less net salvage, where net salvage is gross salvage less cost of removal.

Q. ON PAGE 5, LINES 15-17 OF MR. GARREN'S SURREBUTTAL, HE STATES, '… WHILE ELG DOES NOT REPRESENT ACCELERATED DEPRECIATION IN THE SENSE OF BEING A NON-LINEAR RECOVERY METHOD, IT DOES ACCELERATE RATES NECESSARILY RELATIVE TO THE ALG METHOD." HOW DO YOU RESPOND?

A. I do not dispute that ELG can lead to higher short-term depreciation rates. However, this results from more accurate cost recovery and, contrary to Mr. Garren's apparent opinion, higher depreciation in the short term is neither inappropriate nor harmful to customers. As discussed above, the claim that ELG causes current customers to subsidize future ones is incorrect. ELG *more* precisely aligns costs with the actual service lives of assets and is therefore, less likely to lead to disproportionate cost assignments between generations of customers. Further, customers benefit from a lower rate base under ELG. If anything, Mr. Garren's proposal to transition from ELG to ALG would actually be *to create* a subsidy to current customers by increasing the rate base and lowering depreciation. Under his proposal, current customers would be paying less, but it would be at the expense of future customers who would be required to pay more.

Q. MR. GARREN ARGUES THAT ELG IS INVALID IF RATES ARE NOT UPDATED ANNUALLY.[6] HOW DO YOU RESPOND?

A. Mr. Garren's argument does not align with reality regarding Pennsylvania utilities and is therefore invalid. UGI Gas (and all other major Pennsylvania utilities) update their depreciation rates each year. The Pennsylvania PUC has implemented several important and progressive regulatory changes over the past 44 years that have enhanced its ability to

[6] OCA St. 4SR, at p. 4.

review and monitor the depreciation practices of the utilities it regulates. A few of these long standing changes are present in Pennsylvania ratemaking today but typically are not present in other states, such as the filing of annual depreciation reports, updating depreciation annual accrual rates for book purposes, the overwhelming use of ELG depreciation rates, filing periodic service life studies every five years, the use of the book reserve to determine rate base, the use of a future and fully projected future test year. These enlightened regulatory policy changes have helped make the ratemaking process in PA more transparent and fairer to all stakeholders with regard to depreciation matters.

Q. MR. GARREN SUGGESTS THAT ONE OF THE SHORTCOMINGS OF USING ELG RATES (SL-ELG-RL) IS THAT THEY FLUCTUATE MORE THAN ALG RATES (SL-ALG-RL). ON PAGE 5, LINES 9-13 OF MR. GARREN'S SURREBUTTAL TESTIMONY, HE STATES, "THE ADMINISTRATIVE WORK OF REVIEWING THE RATES DOES NOT YIELD MORE ACCURATE RATES, IT ONLY CAUSES RATES TO FLUCTUATE MORE AS ESTIMATES CHANGE OVER TIME. IF OUR OVERALL LIFE ESTIMATES WERE PERFECTLY ACCURATE AND CONSISTENT, THEN THE PRECISION GAINED BY THE USE OF THE ELG METHOD MIGHT BE WORTHWHILE, BUT IN REALITY, LIFE ESTIMATES CHANGE OVER TIME FOR ALL KINDS OF REASONS." PLEASE COMMENT ON HIS STATEMENT.

A. I have used both the ELG and ALG procedure over the course of my 40-year career performing depreciation studies and have not experienced the excessive fluctuation described by Mr. Garren regarding the ELG procedure. To this observation, I offer UGI Gas's experience to refute Mr. Garren's unsubstantiated claim.

As a matter of regulatory compliance, UGI Gas's service lives are updated on a five-year basis and customer rates are implemented during rate cases within that five-year period. In addition, UGI Gas submits annual depreciation reports ("ADRs") to the PUC, which demonstrate that the composite ELG depreciation rates are relatively stable, despite new capital additions made year-over-year. For example, the table below summarizes the overall composite rates related to distribution plant from the last eleven years, which illustrates that the ELG procedure results in consistent and stable depreciation rates over time. Therefore, Mr. Garren's concerns about the fairness and instability of using ELG depreciation rates are unfounded.

Table 1. UGI Gas Composite ELG Rates – Distribution Plant

Test Year (at 9/30)	Composite Rate
2017	2.05%
2018	2.05%
2019	2.05%
2020	2.08%
2021	2.08%
2022	2.08%
2023	2.08%
2024	2.08%
2025	2.11%
2026E	2.11%
2027E	2.11%

III. DIFFERENCES IN SURVIVOR CURVE ESTIMATES

Q. DID OCA WITNESS GARREN PROPOSE CHANGES TO ANY OF THE SERVICE LIVES FOR ANY ASSET CLASS PROPOSED BY UGI GAS?

A. Yes. Please see the table below for a summary of the service life estimates made by each party for gas plant. This table also includes the currently approved service life estimate.

Table 2: Comparison of Company Proposed and OCA Proposed Survivor Curves

Account	Currently Approved	Company Proposed	OCA Proposed
375.00, STRUCTURES AND IMP.	50-S0.5	50-S0.5	70-O1
376.10, MAINS, PRIMARILY STEEL	75-R2.5	75-R2.5	79-R2
378.00, MEAS. AND REG. EQUIPMENT	48-S0	48-S0	53-R0.5

Q. DID MR. GARREN CONSIDER OTHER RELEVANT FACTORS BESIDES THE HISTORICAL LIFE ANALYSIS FOR HIS SURVIVOR CURVE SELECTION (70-O1) RELATED TO ACCOUNT 375, STURCTURES AND IMPROVEMENTS?

A. No, it appears that he was heavily influenced by the curve-fitting results of the historical life analysis. In fact, he referenced the best fit curve from my workpapers, the 80-O1, which he then reduced to a 70-O1 as his final selection. Mr. Garren criticizes the T-cuts I made in determining the data points I considered statistically significant, although he neither performed his own service life analysis nor did he use any T-cuts in trying to eliminate misleading and statistically insignificant data points on the life table. I made my T-cut at 46.5 based on a review of the exposures, the behavior of the retirement ratios and the life expectation of the underlying assets, which included small metal buildings, sheds and fencing.

Q. ARE THE RESULTS OF THE HISTORICAL LIFE ANALYSIS FOR ACCOUNT 375, STRUCTURES AND IMPROVEMENTS CONCLUSIVE?

A. No, the results are not conclusive. This happens occasionally, particularly for small plant accounts with a variety of assets included such as Account 375, Structures and Improvements. The goodness of fit was only fair, that is, not a poor fit but not an excellent fit either. Mr. Garren's survivor curve selection was an even poorer fit through the significant data points.

Q. WHAT OTHER FACTORS SHOULD BE CONSIDERED PARTICULARLY WHEN THE RESULTS OF THE HISTORICAL LIFE ANALYSES ARE INCONCLUSIVE?

A. There are several relevant factors to consider in all cases and particularly when the historical life analyses are inconclusive. First, in no particular order, is the currently approved survivor curve. The approved survivor curve at the time of the last service life study update is the 50-S0.5, which is the same as the survivor curve proposed in the last service life study. Second is the typical range of service life estimates used by other gas companies. The typical range used by other gas companies is 45-60 years. Third, is company plans and whether those plans will impact future levels of retirements in comparison with prior periods. UGI Gas's LTIIP indicates some of the Company's District M&R Station locations are no longer needed and in the near term will be retired without replacement. I expect retirements to increase in the future for this account. Fourth is to understand the assets included in the account and their expected service lives. The two primary asset groups included in this account are fencing, which should last 30 to 40 years, and small metal buildings and sheds, which should last, on average, 40 to 60 years. Put all these factors together and the 50-year average service life that I have estimated seems more reasonable for this account than the 70-year average service life that Mr. Garren estimated. Additionally, Mr. Garren's 70-O1 survivor curve has a maximum life of 140 years, while my survivor curve estimate (50-S0.5) has a maximum life of 100 years which is more reasonable than Mr. Garren's for the majority of assets included in this account.

Q. DID MR. GARREN RELY ALMOST EXCLUSIVELY ON THE CURVE-FITTING RESULTS FROM THE HISTORICAL SERVICE LIFE ANALYSIS FOR THE OTHER TWO ACCOUNTS?

A. Yes, he did. The problem with just using the results of the historical service life analysis is that it effectively assumes future rates of retirement will be similar to the past. However, for Account 376.1 – Mains – Primarily Steel, UGI Gas has accelerated the replacement of bare steel mains. The Company's bare steel main replacement program will continue until 2041, and I expect higher rates of retirements to appear on future life tables at ages 65 years and older for this account since bare steel mains primarily were installed 1925-1960. Both Mr. Garren's and the Company's survivor curve estimate fit the historical points very well from age 0 through age 65. After age 65, the Company's survivor curve estimate diverges from Mr. Garren's and is steeper than Mr. Garren's proposed survivor curve. The Company's proposed survivor curve, the 75-R.25, anticipates higher rates of retirement to occur in the future, consistent with Company plans as set forth in the LTIIP. This can be observed graphically on Figure 2 of my Rebuttal Testimony. Additionally, the typical range of service lives used by other gas companies for steel mains is 65-75 years, which would put the Company's estimate within the typical range of service life estimates while Mr. Garren's proposed survivor curve estimate is outside the typical range.

Essentially the same overreliance by Mr. Garren on the curve fitting results occurs for Account 378, Measuring and Regulating Station Equipment as well. I have proposed a 48-S0 survivor curve and Mr. Garren has proposed a 53-R0.5. The number 48 in the 48-S0 survivor curve designates the average service life. This is another account where other relevant factors besides the historical service life analysis would have led Mr. Garren to a

different conclusion had he adequately considered Company plans as it relates to increased levels of retirement in the future and the estimates used by other gas companies for Account 378. Most other gas companies estimate service lives in the 40-50 year range for this account.

IV. CONCLUSION

Q. IS THERE ANYTHING IN THE TESTIMONY OF THE OCA WITNESS THAT SHOULD INFLUENCE THE COMMISSION TO ACCEPT HIS DEPRECIATION RECOMMENDATIONS?

A. No. My rejoinder testimony addresses and refutes Mr. Garren's arguments regarding the Company's depreciation methodologies. Mr. Garren's assertion that Gannett Fleming proposes ALG in other cases is not relevant to the current case, as each case in other jurisdictions have their own unique set of circumstances to be evaluated. Mr. Garren also overlooks Gannett Fleming's near unanimous recommendation to its Pennsylvania utility clients to continue to use the ELG procedure. In addition, Mr. Garren ignores Pennsylvania's 44-year successful use of ELG for utility companies throughout the Commonwealth including UGI Gas. While ELG can result in higher short-term depreciation rates, it more precisely aligns costs with asset service lives, avoids creating intergenerational subsidies, and produces lower overall utility rates for customers. Data from ADRs show that composite rates under ELG are stable. And, finally, UGI Gas's depreciation rates are generally lower than those in other states due to Pennsylvania's retroactive recovery net salvage costs, which defers costs to future customers. ELG remains the most accurate and fair method for UGI Gas.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523 et al.

UGI Utilities, Inc. – Gas Division

Statement No. 8-RJ

Rejoinder Testimony of
Dylan W. D'Ascendis

Topics Addressed: **Return on Equity**

Dated: June 1, 2026

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I. INTRODUCTION, PURPOSE AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Partner at ScottMadden, Inc.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this rejoinder testimony (referred to throughout as my "Rejoinder Testimony") before the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission") on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO PROVIDED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REJOINDER TESTIMONY?

A. The purpose of my Rejoinder Testimony is to address certain aspects of the surrebuttal testimonies of Mr. Drew Breuning, witness for the PA PUC's Bureau of Investigation and Enforcement ("I&E"), Mr. David J. Garrett, witness for the Pennsylvania Office of Consumer Advocate ("OCA"), and Mr. Patrick M. Cicero, witness for The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), (collectively referred to as the "Opposing Witnesses") as they pertain to the Company's allowed cost of capital, which the Company should have the opportunity to earn on their authorized jurisdictional rate base.

Q. PLEASE SUMMARIZE THE KEY ISSUES AND RECOMMENDATIONS OFFERED BY THE OPPOSING WITNESSES THAT YOU ADDRESS IN YOUR REJOINDER TESTIMONY.

A. My Rejoinder Testimony responds to substantive recommendations offered by the Opposing Witnesses in their surrebuttal testimonies which are new relative to their direct testimonies. Specifically, I first respond to the Opposing Witnesses' reliance upon recent policy issuances and proposed pieces of legislation to latently bolster their arguments regarding an appropriate rate of return. Next, I respond to certain new arguments presented by Mr. Breuning regarding investment horizons and the cost of capital, reliability of selected data and data sources, my Non-Price Regulated Proxy Group, and his continued misunderstanding of the Commission's application of a size adjustment. Regarding Mr. Garrett, I respond to his contention that a multi-stage discounted cash flow ("DCF") model is appropriate for use in a cost of common equity analysis for utility companies.

Q. IS THERE A COMMON THEME ACROSS THE OPPOSING WITNESSES' SURREBUTTAL TESTIMONIES?

A. Yes, there is. Each Opposing Witness mentions Governor Josh Shapiro's letter to the CEOs of Pennsylvania utilities ("Shapiro Letter"), and Mr. Cicero references the recently introduced House Bill 2224 ("HB 2224") that aims to reform the existing regulatory construct in an attempt to advance their various arguments.

Q. HOW WILL THE REMAINDER OF YOUR REJOINDER TESTIMONY BE ORGANIZED?

A. First, I discuss the Opposing Witnesses' arguments based on the Shapiro Letter and HB 2224. Second, I will address substantive new arguments put forth in Mr. Breuning's

surrebuttal testimony. Finally, I address Mr. Garrett's use of a multi-stage DCF model in his cost of common equity analysis.

II. OPPOSING WITNESS INTERPRETATIONS OF THE SHAPIRO LETTER AND PROPOSED HB 2224

Q. HOW DO THE OPPOSING WITNESSES USE THE SHAPIRO LETTER AND THE PROPOSED HB 2224 TO SUPPORT THEIR CONCLUSIONS?

A. Mr. Breuning briefly cites the Shapiro Letter when discussing the importance of affordability concerns when determining the cost of common equity.[1] Mr. Garrett refers to the Shapiro Letter to support his allegation that the Company is using a double leveraged capital structure.[2] Mr. Cicero cites the Shapiro Letter and the proposed HB 2224 as necessary reform to establish and ROE more consistent with the actual cost of equity.[3] It is my understanding that counsel will address which each of these items cannot and should not be relied upon to support any factual findings and determinations in this matter.

Q. HOW DO YOU RESPOND TO MR. BREUNING'S CONSIDERATION OF CUSTOMER AFFORDABILITY IN DETERMINING THE ROE?

A. Rate of return analysts' assignment in utility general rate cases is to determine the investor required return on common equity at the time of their analysis. Because the ROE is considered in the utility's cost to serve its customers, it is necessary that the regulatory commission allows the utility an opportunity to recover the full cost of capital. To the extent that affordability concerns affect utility risk, documents like the Shapiro Letter and the proposed HB 2224 increase uncertainty about the State's regulatory risk, increasing investor's required returns.

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1 I&E St. No. 2-SR, at p. 25.
2 OCA St. 3SR, at pp. 3-4.
3 CAUSE-PA St. No. 1-SR, at pp. 14-15.

Q. WHAT IS YOUR RESPONSE TO MR. GARRETT'S USE OF THE SHAPIRO LETTER TO SUPPORT HIS ALLEGATION OF UGI'S USE OF DOUBLE LEVERAGE?

A. As a preliminary matter, Mr. Garrett offers no response to my arguments or support in the academic literature refuting his allegations of the Company's use of double leverage at pages 12 through 16 of my Rebuttal Testimony. Further, while the Shapiro Letter may prefer the use of the utility's parent capital structure, it does not allege double leveraging of the capital structures of all Pennsylvania utilities (or UGI Gas specifically), nor does it recommend disallowing utility capital structures that are different than their parent. Simply, the Shapiro Letter recommends a full evaluation of a utility's capital structure for reasonableness, which has always been the task of the Commission in all general rate cases.

Q. PLEASE RESPOND TO MR. CICERO'S OPINION THAT THE PROPOSED HB 2224 WILL ESTABLISH EQUITY RETURNS MORE CONSISTENT WITH THE ACTUAL COST OF EQUITY.

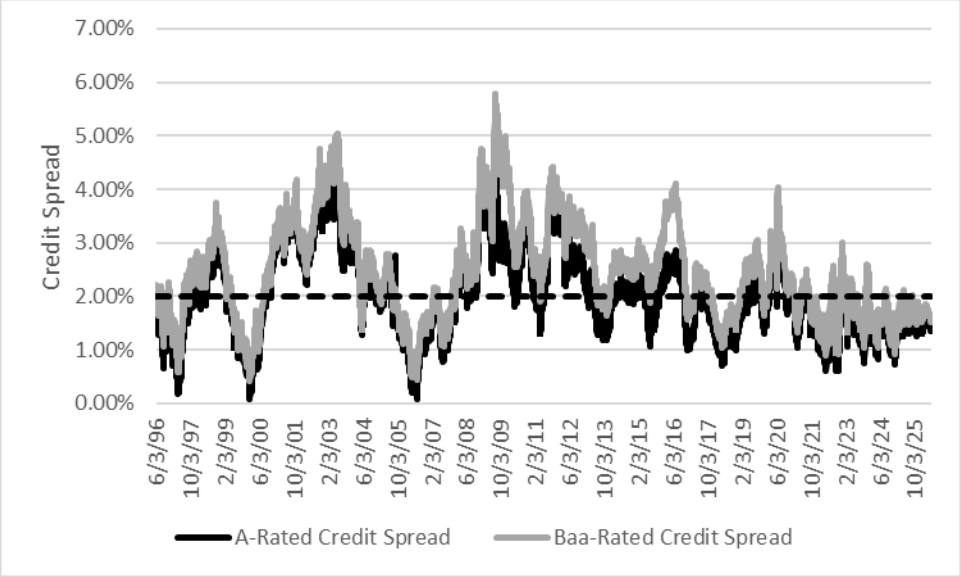
A. I disagree with Mr. Cicero's opinion that methodologies outlined in the proposed HB 2224 would establish ROEs that would reflect the actual cost of common equity.

Q. CAN YOU GIVE A SIMPLE EXAMPLE THAT DEMOSTRATES THE INADEQUACY OF THE INDICATED ROE DERIVED USING THE "DEFAULT AUTHORIZED RETURN" FORMULA USED IN THE PROPOSED HB 2224?

A. Yes, I can. The proposed HB 2224 states that in the absence of an ROE resulting from a "competitive equity auction", the ROE that would be used to set rates would be set at the "default authorized return", which is calculated by adding 200 basis points to a recent average yield on ten-year Treasury bonds. To attempt to evaluate the validity of the formula, I calculated yield spreads between the ten-year Treasury bond yield and A- and

Baa-rated public utility bonds from 1996 to the present. The results of that analysis are shown on Chart 1, below:

Chart 1: Yield Spreads between Ten-Year Treasury Bonds and A- and Baa-rated Public Utility Bonds – 1996 - Present[4]



As can be gathered from the Chart above, yields on A- and Baa-rated public utility bonds commonly exceed the yield on ten-year Treasury bonds by over 200 basis points. In fact, for the 30-year period, the average yield spread between ten-year Treasury bonds and A- and Baa-rated public utility bonds are 2.02% and 2.44%, respectively. When the yield spreads are above the 2.00% line shown on Chart 1, that means that the cost of debt exceeded the implied cost of common equity as calculated by the "default authorized return" formula. Because investing in a company's equity is generally riskier than investing in its debt, as equity investors are last in line in the event of a company's liquidation, any indicated ROE for a company that is less than its marginal cost of debt would be illogical. In the 30-year timeframe measured in Chart 1, the marginal cost of

[4] Source of Information: Bloomberg Professional Services.

debt exceeded the implied cost of equity using the "default authorized return" 46% of the time when using an A-rated public utility bond and 63% of the time when using a Baa-rated public utility bond yield.[5]

While I have significant concerns with the entirety of the proposed HB 2224 including the mechanics and application of the "competitive equity auction", this simple example shows how disconnected the proposed legislation's default assumption is from the "actual cost of equity'.

III. RESPONSE TO I&E ROE WITNESS BREUNING

Q. PLEASE SUMMARIZE BREUNING'S SUBSTANTIVE AND NEW ARGUMENTS PRESENTED IN HIS SURREBUTTAL TESTIMONIES.

A. Mr. Breuning discusses the following new arguments in his surrebuttal testimony: (1) his assertion that the investment horizon is a function of the investor, not the investment; (2) that Kroll is a trusted and publicly available source; (3) that the DCF model does not have subjective inputs; (4) that beta and the standard error of the regression are only measures of past performance; and (5) that the use of non-utility proxy groups violate the principles set forth in *Hope* and *Bluefield*.

Q. IN DEFENDING HIS USE OF THE TEN-YEAR TREASURY BOND YIELD IN HIS APPLICATION OF THE CAPM, MR. BREUNING STATES THAT THE COST OF EQUITY IS NOT A LONG-TERM CONCEPT AND THAT INDIVIDUAL INVESTOR'S INVESTMENT HORIZONS ARE RELEVANT.[6] DO YOU AGREE?

A. No, I do not. Mr. Breuning has a fundamental misunderstanding of the nature of the cost of capital. The objective of a cost of equity analysis is to determine the investor required

[5] The credit spread equaled or exceeded 200 basis points on 3,614 days using an A-rated public utility bond and 4,958 days using a Baa-rated public utility bond. The total time period used in the study was 7,818 days.

[6] I&E St. No. 2-SR, at pp. 7-8.

ROE based on the risk of the investment, in which operations are assumed to be operating indefinitely. The investment horizons of individual investors no bearing on the risks inherent in utility operations, and as such, inputs to models that reflect an individual investor's finite investment should not be considered

Q. DO ANY OF THE COST OF COMMON EQUITY MODELS USED BY MR. BREUNING ASSUME AN INDEFINITE HOLDING PERIOD?

A. Yes. Mr. Breuning's preferred cost of common equity model, the DCF, assumes an indefinite holding period as only the income return is realized by investors. Given the above, Mr. Breuning's reasoning to use the ten-year Treasury bond yield in favor of the 30-year Treasury bond yield in his CAPM analysis is misinformed.

Q. DO YOU AGREE WITH MR. BREUNING'S ASSERTION THAT KROLL IS A TRUSTED AND PUBLICLY AVAILABLE SOURCE?[7]

A. No, I do not. First, Kroll is not a publicly available source, as it is subscription-based and not available unless a subscriber pays the applicable fees. Second, while I do agree with Mr. Breuning that Kroll's historical data is trusted by many financial professionals, I do not agree with his characterization that Kroll's "recommended MRP" is trustworthy or relied upon by investors. In my Rebuttal Testimony, I showed that Kroll's estimates of the market return understate the MRP by wide margins when compared to other measures.[8]

[7] I&E St. No. 2-SR, at p. 14.
[8] UGI Gas St. No. 8-R, at pp. 28-30, 47.

Q. DO YOU AGREE WITH MR. BREUNING'S ASSERTION THAT THE INPUTS TO THE CAPM ARE HIGHLY SUBJECTIVE, WHILE THE INPUTS TO THE DCF MODEL ARE NOT?[9]

A. No, I do not. All ROE models are only as good as their inputs, and all ROE models can be easily manipulated by changing those inputs. As is the case with the CAPM, the DCF model has a number of inputs and variations of inputs that can drastically alter results as shown on Table 1:

Table 1: Various Inputs to DCF Models

Input	Variations of Inputs
Cash Flow Stream	Constant-Growth, Blended Growth, Multi-Stage Growth
Dividend Yield	Spot dividend yield, average dividend yield
Adjusted Dividend Yield	No adjustment, ½ g adjustment, full g adjustment, projected dividend
Growth Rates	Historical v. Projected v. Sustainable
Growth Measure	Earnings Per Share ("EPS"), Dividends Per Share ("DPS"), Book Value Per Share ("BVPS")
Sources of Growth Rates	*Value Line*, Zacks, Yahoo, MorningStar, etc.

Q. MR. BREUNING STATES THAT THE BETA AND STANDARD ERROR OF A STOCK ARE ONLY MEASURES OF PAST PERFORMANCE AND NOT WHERE AN INDUSTRY IS GOING OR THE RISKS IT IS EXPECTED TO FACE.[10] **PLEASE RESPOND.**

A. Mr. Breuning's statement again demonstrates his fundamental misunderstanding of the nature of the cost of capital. Market-based cost of capital analyses are a snapshot in time when the analyses are run, similar to cost of capital decisions by regulatory commissions. When the Non-Price Regulated Proxy Group was selected, those companies were of

[9] I&E St. No. 2-SR, at p. 9.
[10] I&E St. No. 2-SR, at p. 15.

comparable risk to the Utility Proxy Group at the time of the analysis. As such, investors would require a similar return on those investments to investments in the Utility Proxy Group.

Q. IS IT YOUR OPINION THAT THE USE OF NON-UTILITY PROXY GROUPS VIOLATES THE PRINCIPLES SET FORTH IN *HOPE* AND *BLUEFIELD*, AS REPRESENTED BY MR. BREUNING'S COUNSEL?

A. No. As discussed in my Direct Testimony,[11] using comparable risk companies to determine a cost of capital for a utility company is consistent with the "corresponding risk" standard in *Hope* and *Bluefield*. Whether the company is regulated or not is not contemplated by the United States Supreme Court. While I do agree that the return in this case should not be based on companies that are not of comparable risk, as discussed above and previously, I have shown that the companies that form my Non-Utility Proxy Group have comparable risk to the Utility Proxy Group, and in turn UGI Gas.[12]

Q. MR. BREUNING CONTINUES TO ASSERT THAT THE COMMISSION HAS NOT AWARDED A SIZE ADJUSTMENT.[13] PLEASE RESPOND.

A. Despite what Mr. Breuning believes, the Commission explicitly recognized size as a factor in awarding a DCF cost rate one standard deviation above the mean in Docket No. R-2019-3008212:

> Based upon the evidence of record, we agree with the recommendation of the ALJs that the Company be awarded a DCF cost of common equity of 9.49%, which is one standard deviation above the average of the mean and median proxy group ROE from the Company's DCF analysis. **In so doing, we recognize that the Company's size is a factor in assessing its ability to attract capital.**[14]

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11 UGI Gas St. No. 8, at p. 65.
12 UGI Gas St. No. 8-R, at pp. 21-23.
13 I&E St. No. 2-SR, at pp. 21-22.
14 Pennsylvania Public Utility Commission, Docket No. R-2019-3008212, Opinion and Order, at 103. Emphasis added.

IV. RESPONSE TO OCA ROE WITNESS GARRETT

A. MISAPPLICATION OF THE DISCOUNTED CASH FLOW MODEL

Q. PLEASE BRIEFLY DESCRIBE MR. GARRETT'S CONSTANT GROWTH DCF ANALYSES AND RESULTS.

A. Mr. Garrett applied "sustainable" growth rates to the constant growth DCF Model, which produced an ROE estimate of 7.60%.[15] For the dividend yield component, Mr. Garrett relied on annualized dividend payments and 30-day average stock prices as of April 2, 2026.[16] To estimate expected growth, Mr. Garrett looked to two measures: (1) nominal Gross Domestic Product ("GDP") and (2) real GDP.[17] Of those two measures, he chose the highest estimate, 3.80%.[18] In addition, Mr. Garrett calculated his DCF results based on projected DPS growth rates from *Value Line*, which produce an average DCF result of 8.20%,[19] but he does not consider either in his cost of equity estimate.[20]

Q. WHAT ARE YOUR GENERAL CONCERNS WITH THE SUSTAINABLE GROWTH RATES ON WHICH MR. GARRETT'S DCF ANALYSIS RELIES?

A. First, Mr. Garrett assumed a single, perpetual growth rate of 3.80% for all his proxy companies.[21] By reference to the Congressional Budget Office's expected inflation rate of 2.20%, Mr. Garrett's method assumed his proxy companies all will grow at real rates of approximately 1.60%, in perpetuity.[22] It is unlikely an investor would be willing to assume the risks of equity ownership in exchange for expected growth only modestly greater than

15 OCA St. 3, at p. 27.
16 Exhibit DJG-3.
17 Exhibit DJG-5.
18 OCA St. 3, at pp. 26-27.
19 Exhibit DJG-6.
20 OCA St. 3, at p. 27.
21 Exhibit DJG-6.
22 Exhibit DJG-5; 2.20% equals nominal GDP of 3.80% minus real GDP of 1.60%.

expected inflation. The risk simply is not worth the expected return.[23] In addition, as a practical matter, because they are generic in nature, his estimate fails to account for the risks and prospects faced by the proxy companies.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH THE 3.80% GROWTH RATE ASSUMED FOR ALL COMPANIES IN MR. GARRETT'S DCF ANALYSIS?

A. Mr. Garrett's 3.80% growth rate is not based on any measure of company-specific growth, or growth in the utility industry in general. Rather, his proxy group serves the sole purpose of calculating the dividend yield. Under the DCF model's strict assumptions, however, expected growth and dividend yields are inextricably related. Mr. Garrett's assumption that one growth rate applies to all companies, even though dividend yields vary across those companies, has no basis in theory or practice.

Q. PLEASE RESPOND TO MR. GARRETT'S POSITION AND COMMENTS REGARDING "STEADY-STATE" GROWTH RATES.

A. While I agree with Mr. Garrett's statement regarding regulated utilities being in the "mature" stage in the company/industry life cycle, I disagree with his conclusion regarding the long-term growth rates of regulated utilities.

As Mr. Garrett describes, the multi-stage DCF and its growth rates reflect the company/industry life cycle, which is typically described in three stages: (1) the growth stage, which is characterized by rapidly expanding sales, profits, and earnings. In the growth stage, dividend payout ratios are low in order to grow the firm; (2) the transition stage, which is characterized by slower growth in sales, profits, and earnings. In the

[23] In the risk/return space, debt securities, with a higher yield and considerably less risk of capital loss (if held to maturity) may be the preferred alternative.

transition stage, dividend payout ratios increase, as their need for exponential growth diminishes; and (3) the maturity (steady-state) stage, which is characterized by limited, slightly attractive investment opportunities, and steady earnings growth, dividend payout ratios, and returns on equity.

Since the utility industry is in the mature phase of the company life cycle, it is the company-specific projected EPS growth rate that is the appropriate measure of growth in a constant growth DCF model, not the projected GDP growth rate as Mr. Garrett asserts.

Q. ARE THERE EXAMPLES IN BASIC FINANCE TEXTS THAT SUPPORT YOUR POSITION?

A. Yes. For example, in Investments, life cycles and multi-stage growth models are discussed:

> As useful as the constant-growth DDM (dividend discount model) formula is, you need to remember that it is based on a simplifying assumption, namely, that the dividend growth rate will be constant forever. In fact, firms typically pass through life cycles with very different dividend profiles in different phases. In early years, there are ample opportunities for profitable reinvestment in the company. Payout ratios are low, and growth is correspondingly rapid. In later years, the firm matures, production capacity is sufficient to meet market demand, competitors enter the market, and attractive opportunities for reinvestment may become harder to find. In this mature phase, the firm may choose to increase the dividend payout ratio, rather than retain earnings. The dividend level increases, but thereafter it grows at a slower pace because the company has fewer growth opportunities.
>
> Table 18.2 illustrates this pattern. It gives Value Line's forecasts of return on assets, dividend payout ratio, and 3-year growth in earnings per share for a sample of the firms in the computer software industry versus those of east coast electric utilities…
>
> By in large, the software firms have attractive investment opportunities. The median return on assets of these frms is forecast to be 19.5%, and the firms have responded with high plowback ratios. Most of these firms pay no dividends at all. The high return on assets and high plowback result in rapid growth. The median growth rate of earnings per share in this group is projected at 17.6%.

> In contrast, the electric utilities are more representative of mature firms. Their median return on assets is lower, 6.5%; dividend payout is higher, 68%; and median growth is lower, 4.6%.
>
> * * *
>
> To value companies with temporarily high growth, analysts use a multistage version of the dividend discount model. Dividends in the early high-growth period are forecast and their combined present value is calculated. Then, once the firm is projected to settle down to a steady-growth phase, the constant-growth DDM is applied to value the remaining stream of dividends.[24] (Clarification added)

The economics of the public utility business indicate that the industry is in the steady-state, or constant-growth stage of a multi-stage DCF, which would mean that the three- to five-year projected growth rates for each company would be the "steady-state" or terminal growth rate appropriate for the DCF model for utility companies, not the GDP growth rate, which is not a company-specific growth rate, nor is it an upward bound for growth, as discussed in my Rebuttal Testimony.[25]

Q. HAVE OTHER COMMISSIONS PREVIOUSLY STATED A POSITION WITH RESPECT TO MR. GARRETT'S USE OF GDP-DERIVED GROWTH RATES AS INPUTS IN THE DCF MODEL?

A. Yes. In Peoples' Gas' rate case in Florida (Docket No. 20230023-GU), the Florida Public Service Commission found Mr. Garrett's use of GDP growth rates inappropriate for reasons similar to those noted above, stating:

> Witness Garrett's argument to use the GDP growth rate in his DCF model is not supported by persuasive evidence. We agree with witness D'Ascendis that the growth rate should reflect a measure of the utilities' individual growth, and not a generic measure of the output of the entire economy.[26]

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[24] Bodie, Kane, and Marcus, Investments, 7th Edition, McGraw-Hill Irwin, 2008, at 616-617.
[25] UGI Gas St. No. 8-R, at pp. 56-57.
[26] In re: Petition for rate increase by Peoples Gas System, Inc., Docket No. 20230023-GU, *Order Granting in Part and Denying in Part Peoples Gas System, Inc.'s Petition for a Rate Increase*, at 62 (December 27, 2023).

Q. DO YOU AGREE WITH MR. GARRETT'S USE OF PROJECTED GDP GROWTH RATES IN HIS DCF MODEL BASED ON ANALYST GROWTH RATES?

A. No, I do not. As discussed above, the appropriate measure for growth in a DCF model is analyst projected growth rates in EPS. In view of the above, I recommend the Commission rely solely on projected EPS growth rates, as Mr. Breuning has proposed, when determining the indicated ROE for UGI Gas using the DCF model.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY

A. Given the discussion above and the updated analysis provided in my Rebuttal Testimony, an ROE of 10.75% remains reasonable for UGI Gas at this time.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.75% FAIR AND REASONABLE FOR UGI GAS AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523 et al.

UGI Utilities, Inc. – Gas Division

Statement No. 11-RJ

Rejoinder Testimony of
John D. Taylor, CEO
Atrium Economics, LLC

Topics Addressed: **Cost of Service**
Residential Customer Charge
Weather Normalization Adjustment

Dated: June 1, 2026

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III. Residential Customer Charge and Low-Income Customer Impact 4
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as Chief Executive Officer ("CEO"). My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 11, on January 28, 2026, and rebuttal testimony, UGI Gas Statement No. 11-R, on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain arguments of the surrebuttal testimony submitted by other parties. The areas I address are outlined below, with reference to the corresponding surrebuttal testimony of the other parties:

Allocated Class Cost of Service

- Office of Consumer Advocate ("OCA") Statement 1SR – surrebuttal testimony of Michael Deupree ("OCA witness Deupree")

Residential Customer Charge Levels

- OCA witness Deupree
- OCA Statement 6SR – surrebuttal testimony of Roger D. Colton ("OCA witness Colton")
- Coalition For Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1-SR – surrebuttal testimony of witness Patrick M. Cicero ("CAUSE-PA witness Cicero")

- Bureau of Investigation and Enforcement ("I&E") Statement No. 3-SR – surrebuttal testimony of Ethan H. Cline ("I&E witness Cline")

Weather Normalization Adjustment ("WNA")

- OCA witness Deupree
- OCA Statement 5SR – surrebuttal testimony of Barbara R. Alexander ("OCA witness Alexander")
- CAUSE-PA witness Cicero
- I&E witness Cline

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No.

II. ALLOCATED CLASS COST OF SERVICE STUDY ("ACOSS")

Q. Has OCA witness Deupree's surrebuttal caused you to change your opinion regarding the Company's use of the Average and Excess ("A&E") methodology for distribution mains?

A. No. Mr. Deupree's surrebuttal largely reiterates arguments previously advanced in his direct testimony regarding the Seaboard method, annual throughput concepts, and the weighting of peak demand within mains allocation methodologies.[1] However, his surrebuttal still does not refute the fundamental engineering reality that distribution mains must be designed to satisfy peak-day system requirements. Mr. Deupree continues to rely on a 1952 order from the Federal Power Commission,[2] which is no longer relevant, since in 1973 the Federal Energy Regulatory Commission ("FERC") departed from this

[1] OCA St. 1, pp. 50-54 and OCA St. 1SR, pp. 12-16.
[2] OCA St. 1SR, p. 12.

Seaboard method to the United method and then subsequently moved to a Modified Fixed variable approach in 1983, which allocated all fixed costs based on demand and all variable costs based on commodity. This Commission should not rely on precedents from 1952 that have since been replaced.

Q. How do you respond to OCA witness Deupree's claim that the A&E methodology considers a customer class with a 100 percent load factor as having no peak demand requirements?[3]

A. I disagree with that characterization because it is factually inaccurate. Under the A&E methodology, a customer class with a 100 percent load factor is not viewed as having no peak demand requirements. Rather, it is viewed as having peak demand requirements that are equal to its average demand requirements.

In the example provided by OCA witness Deupree, the excess demand component is zero because there is no difference between the class's average demand and its peak demand. That does not mean the class imposes no demand on the system or has no peak demand requirements. On the contrary, the class is utilizing the system at its full demand level during all hours, including the system peak period. Accordingly, the A&E methodology does allocate demand-related costs to such a customer class. Those costs are simply assigned to the average demand component rather than the excess demand component. Mr. Deupree's example, therefore, conflates the absence of excess demand

[3] OCA St. 1SR, p. 16.

with the absence of peak demand, which are fundamentally different concepts. In my view, OCA witness Deupree's example incorrectly interprets the results of the A&E methodology by treating zero excess demand as equivalent to zero peak demand. The methodology makes no such assumption.

III. RESIDENTIAL CUSTOMER CHARGE AND LOW-INCOME CUSTOMER IMPACT

Q. Please respond to OCA witness Deupree's testimony regarding the appropriate level of recovery of customer-related costs through the residential customer charge.

A. Mr. Deupree's analysis understates the appropriate level of customer-related cost recovery through the residential customer charge because it excludes legitimate customer-related overhead and administrative costs that are necessary to provide service.[4] Those costs are real, ongoing costs the Company incurs to connect, bill, serve, and support customers, and they are properly included in the Company's cost of service study consistent with standard ratemaking principles.

Mr. Deupree acknowledges that the current residential customer charge recovers only about 42 percent of the customer-related costs identified in his own analysis, which he calculates at $38.66 per customer per month.[5] That amount is materially higher than the Company's proposed charge. In my view, recovery at only 42 percent of customer-related costs does not reasonably reflect cost-causation principles, and Mr. Deupree's proposal is

[4] OCA St. 1SR, pp. 18-19.
[5] OCA St. 1SR, p. 17.

not supported by the *Lloyd* decision[6] because it would continue to recover customer-related costs well below the cost to serve without justification. Accordingly, I continue to support the Company's proposed $23.00 monthly residential customer charge as a more appropriate reflection of customer-related costs, regardless of any scale-back or the ultimate revenue requirement. Even at that level, the charge would still recover less than 50 percent of the unit cost calculated by Mr. Deupree.

Q. Please respond to OCA witness Colton's surrebuttal testimony regarding your criticism of the OCA witnesses' statements concerning lower-use and lower-income customers.[7]

A. Mr. Colton's surrebuttal does not address my central point. My rebuttal did not depend on which specific OCA witness used a particular phrase. Rather, my point was that OCA, as a whole, advanced the position that lower-use residential customers tend to be lower-income customers without providing Company-specific evidence or analysis showing that relationship for UGI Gas customers. Specifically, OCA witness Deupree stated the following in his direct testimony:

> As discussed in more detail in the Direct Testimony of OCA Witness Roger Colton, higher customer charges disproportionately impact lower use residential customers which tend to be lower income customers.[8]

[6] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).
[7] OCA St. 6SR, p. 25-26.
[8] OCA St. 1, p. 68.

Mr. Deupree also cites the Direct Testimony of Roger Colton, OCA Statement No. 6 at pages 10 and 11. In other words, Mr. Deupree expressly represented that Mr. Colton's testimony would support that assertion. But Mr. Colton's testimony did not even provide testimony that lower-use customers are or are not generally lower-income customers, as Mr. Colton acknowledges in his own surrebuttal testimony.[9] Instead of addressing that lack of evidentiary support, Mr. Colton's surrebuttal focuses on whether he personally made the statement referenced in my rebuttal testimony. That distinction misses the point. OCA advanced the assertion in this proceeding, attributed support for it to one of its witnesses, and ultimately left it unsupported. Therefore, my criticism remains unchanged. OCA continues to advance this position without factual support in the record, leaving the Commission without an evidentiary basis to rely on that assertion.

Q. Does OCA continue to make the argument that low-income customers are typically low-use customers?

A. Yes. In his surrebuttal testimony, OCA witness Deupree continues to advance the premise that low-income customers are low-use customers, but he does not provide Company-specific evidence demonstrating that this is true for UGI Gas customers.[10] Instead, he criticizes the Company's low-income analysis based on incorrect assertions, including the claim that the analyzed population included customers enrolled in the Customer Assistance

[9] OCA St. 6SR, p. 25-26.
[10] OCA St. 1SR, pp. 18-19.

Program ("CAP"), when it did not.[11] As a result, his criticism does not undermine the Company's analysis and does not supply evidentiary support for OCA's underlying claim.

Q. How do you respond to CAUSE-PA witness Cicero's continued opposition to the Company's proposed residential customer charge increase?[12]

A. Mr. Cicero's surrebuttal continues to reflect a policy preference for recovering a larger portion of fixed distribution costs through volumetric rates.[13] As discussed in my rebuttal testimony, the Company's proposed customer charge is supported by cost causation principles and the Company's ACOSS[14] as well as the customer-related costs calculated by OCA witness Deupree. Mr. Cicero has not presented evidence in this proceeding undermining that analysis.

Q. How do you respond to CAUSE-PA witness Cicero's position that the Company's Budget Billing Program should be used in lieu of increasing the residential customer charge?[15]

A. Mr. Cicero's position suffers from the same fundamental flaws I addressed in rebuttal when OCA witness Deupree suggested that the Budget Billing Program offers the same features as the WNA for purposes of normalizing bills.[16] Budget billing is a payment-smoothing

[11] UGI Gas St. No. 11, pp. 28-29.
[12] CAUSE-PA St. 1-SR, p. 32.
[13] CAUSE-PA St. 1-SR, pp. 33-34.
[14] UGI Gas St. No. 11-R, pp. 17-18.
[15] CAUSE-PA St. 1-SR, p. 32.
[16] OCA St. 1, at p. 31.

mechanism, not a rate design mechanism. As a payment plan, it cannot substitute for either traditional rate design or alternative ratemaking mechanisms.

Q. I&E witness Cline states that "a delicate balance exists in rate design between the revenue stability and fixed cost recovery (the Company) and affordability and conservation efforts (customers)."[17] Do you disagree with that statement?

A. I agree that rate design requires the Commission to balance multiple objectives, including cost causation, revenue stability, customer bill impacts, affordability, and conservation. However, I do not agree with framing those considerations as though revenue stability and fixed cost recovery are solely "Company" interests, while affordability and conservation are solely "customer" interests.

As discussed in my direct and rebuttal testimony, appropriately designed customer charges and rate structures can benefit both customers and the Company. More stable recovery of fixed customer-related costs can reduce weather- and usage-related bill volatility, moderate the need for future rate adjustments, improve revenue stability, improve bill stability, which may lower arrears and uncollectibles, and better align cost recovery with how those costs are incurred.[18]

Similarly, affordability and conservation are not concerns that affect only customers. The Company also has a strong interest in customer affordability, bill stability, gradualism, and efficient system utilization, all of which are longstanding and recognized

[17] I&E St. 3-SR, p. 6.
[18] UGI Gas St. No. 11, pp. 27-30 and UGI Gas St. No. 11-R, pp. 17-18, 26-28.

objectives of sound utility ratemaking. In practice, rate design requires balancing interrelated considerations that affect both customers and the Company, not weighing a set of exclusively "Company" interests against a separate set of exclusively "customer" interests.

For that reason, I continue to believe customer charges should be set primarily based on cost-causation principles and the customer-related costs identified in the ACOSS, while also considering gradualism and customer impacts. They should not be reduced mechanically as a simple proportional function of changes in the overall revenue requirement approved by the Commission.

In this case, the Company's proposed customer charge already reflects moderation and gradualism because it remains below the customer-related unit cost identified in both the Company's ACOSS and OCA witness Deupree.[19] Accordingly, further reducing that charge solely because the Commission may adjust the overall revenue requirement would move rates farther from cost-based recovery without any showing that the underlying customer-related costs themselves have changed.

Q. What is the outcome of continued pursuit of inefficient rate design?

A. When rates are designed to recover significant portions of fixed costs through volumetric charges as proposed by OCA, CAUSE-PA, and I&E, logical alternatives are rightfully pursued as a solution for the inefficiency of design. Take the WNA for example. If rates were efficiently designed to recover fixed costs in fixed charges and variable costs in

[19] UGI Gas St. No. 11, pp. 26-27.

volumetric charges, i.e., a Straight-Fixed-Variable ("SFV") rate design, the WNA would not be needed. However, the shift away from an efficient rate design goal, as advocated for by the parties in this case, necessitates the focus on WNA and similar alternative rate mechanisms to achieve recovery of the fixed costs of providing service. This is due to rate designs that recover significant portions of fixed costs through volumetric charges, creating both: (1) increased revenue instability for the utilities charged with providing safe and reliable service; and (2) increased bill stability for customers. The root of the problem here is that the further the rate design deviates from SFV, sending incorrect price signals to customers, efficiently-designed alternatives are understandably pursued. When cost recovery is aligned with cost causation and efficient rates are provided to customers, these alternatives are not necessary or only needed in more limited form, and all customers pay fairly for the same access to the same safe and reliable utility systems.

IV. WEATHER NORMALIZATION ADJUSTMENT

Q. Did you review the 2009 report cited by OCA witness Deupree,[20] and does it support his characterization of the Company's proposed WNA?

A. I did review the report titled *Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review* by Pamela G. Lesh, which OCA witness Deupree cites. The report does not support witness Deupree's conclusion that the Company's proposed WNA is one-sided or operates primarily for the benefit of the utility. To the contrary, the report states that decoupling adjustments "are both refunds to

[20] OCA St. 1SR, pp. 18-19.

customers as well as charges and tend to be small."[21] This is clearly stated in the report's abstract – right up top in italicized letters. It further states that no consistent pattern of either rate increases or decreases emerges, and that the adjustments were "most often under 2 percent," with "the majority under 1 percent."[22] Those conclusions are inconsistent with OCA's suggestion that such mechanisms operate asymmetrically or primarily to customers' detriment.

Q. Why is that report of limited applicability to the Company's proposed WNA?

A. The report has limited applicability for at least two reasons. First, it was published approximately 17 years ago and evaluated mechanisms that differ materially from the WNA structures currently used in Pennsylvania. Second, the report expressly notes that most of the mechanisms it reviewed did not adjust revenues for the effects of weather.[23] That limitation is significant because the Company's proposed WNA is specifically designed to normalize only for weather-related variation around the same weather assumptions used to establish base rates. Accordingly, the study does not provide a meaningful basis to assess the operation of a modern Pennsylvania WNA.

Q. How does the Company's proposed WNA differ from the broader decoupling mechanisms evaluated in the report?

[21] Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," The Electricity Journal, Vol. 22, Issue 8 (Oct. 2009), p. 66.
[22] *Id.*
[23] *Id.* p. 67.

A. The distinction is important. Many of the revenue decoupling mechanisms discussed in the report were designed to address broader revenue variation associated with changes in customer usage, including conservation, energy efficiency, economic conditions, and other non-weather factors.[24] The Company's proposed WNA does not do that. It is not a general revenue decoupling mechanism. Rather, it is narrowly designed to normalize only for weather-related deviations from the weather assumptions embedded in rates. For that reason, the historical operation of broader decoupling mechanisms does not establish that the Company's proposed WNA is one-sided or primarily beneficial to the utility. Like the mechanisms described in the report, the proposed WNA operates symmetrically and can produce either customer credits or surcharges depending on actual weather conditions.

Q. Please respond to OCA witness Deupree's continued claim that the WNA has functioned as an "asymmetric" mechanism because it has produced more surcharges than credits.[25]

A. Mr. Deupree's claim continues to confuse the design of the WNA with the weather outcomes observed during the review period. The WNA is symmetrical by design because it can produce either surcharges or credits depending on if the actual weather is warmer or colder than the normal weather embedded in rates. The fact that the historical period experienced more warmer-than-normal conditions than colder-than-normal conditions

[24] *Id.*
[25] OCA St. 1SR, pp. 7-8.

does not make the mechanism asymmetric; it reflects the weather that occurred, not a one-sided feature of the mechanism. The Company does not control those weather outcomes.

What the Company can do, and has done, is improve the assumptions used in the mechanism so that the normal weather benchmark better reflects recent conditions. Specifically, the Company updated the weather normalization from a 15-year average to a more current 10-year average.[26] As shown in this proceeding, if that 10-year normalization had been applied over the historical review period, customers would have been approximately neutral overall, meaning the mechanism would have produced approximately offsetting surcharges and credits over the historical review period.[27] That result directly undermines Mr. Deupree's claim that the WNA is inherently one-sided. Notably, Mr. Deupree does not contradict, let alone address, the data presented in Table 2 of my rebuttal testimony demonstrating that a 10-year normal would have resulted in total WNA collections of approximately $130,000 from November 2022 to March 2026, compared to the actual total WNA collections over that period of approximately $63.44 million.

Q. Please respond to OCA witness Deupree's recommendation to increase the WNA deadband from 3% to 5% and to exclude October from the WNA period.[28]

A. Mr. Deupree continues to focus exclusively on limiting potential customer surcharges while largely ignoring the corresponding impacts on customer credits and the overall

[26] UGI Gas St. No. 11, p. 33.
[27] UGI Gas St. No. 11-R, pp. 33-34.
[28] OCA St. 1SR, pp. 9-11.

effectiveness of the WNA. Increasing the deadband from 3% to 5% would not merely filter out insignificant deviations. It would leave a wider range of meaningful weather-related usage variation outside the mechanism, thereby reducing both surcharges in warmer-than-normal periods and credits in colder-than-normal periods. As demonstrated during the colder-than-normal 2025-2026 winter season, the deadband also limited the credits customers otherwise would have received.[29]

The same is true of Mr. Deupree's proposal to exclude October from the WNA period. Although October accounts for a smaller share of annual heating degree days than the core winter months, it still includes heating requirements and weather-sensitive usage.[30] The relevant question is not whether October is among the coldest months of the year, but whether deviations from normal October weather can impact residential heating usage. The evidence in this case shows that they do.[31]

Q. How do you respond to OCA witness Alexander's and CAUSE-PA witness Cicero's claim that the absence of customer complaints should not be interpreted as evidence of customer acceptance or understanding of the WNA?[32]

A. OCA witness Alexander and CAUSE-PA witness Cicero criticize the Company for drawing reasonable inferences from observable customer complaint data, yet their

[29] UGI Gas St. No. 11-R, p. 46.
[30] OCA St. 1SR, p. 11.
[31] UGI Gas St. No. 11-R, pp. 33-34.
[32] OCA St. 5-SR, p. 8 and CAUSE-PA St. 1-SR, p. 38.

responses rely on speculation regarding hypothetical customer perceptions unsupported by any analysis, survey data, complaint trends, or empirical evidence.

Q. How do you respond to CAUSE-PA witness Cicero's continued criticism of the WNA?[33]

A. Mr. Cicero's surrebuttal simply reiterates arguments I have already addressed in my rebuttal testimony regarding the operation of the WNA, the allocation of weather-related risk, and the historical pattern of WNA surcharges and credits.[34]

Q. How do you respond to CAUSE-PA witness Cicero's continued request to modify the WNA mechanism deadband and months of application?[35]

A. I address those same arguments in my responses to I&E witness Cline below. As discussed there, those proposed changes are not informative and do not provide a persuasive basis to modify the WNA.

Q. Please respond to I&E witness Cline's recommendation to increase the WNA deadband from 3% to 5% which relies on the Commission's decision in the Columbia Gas of Pennsylvania, Inc. ("Columbia Gas") 2025 Rate Case.[36]

[33] CAUSE-PA St. 1-SR, p. 36-37, 40.
[34] CAUSE-PA St. 1-SR, pp. 36, 40 and UGI Gas St. No. 11-R, pp. 43-44.
[35] CAUSE-PA St. 1-SR, pp. 41-42.
[36] I&E St. 3-SR, pp. 3-4.

A. I continue to disagree with increasing the WNA deadband from 3% to 5%.[37] While I do not dispute that a 5% deadband may have been found reasonable for Columbia Gas based on the record and WNA design presented in that proceeding, it does not mean a 5% deadband is the most appropriate result for UGI Gas in this proceeding. The question here is not whether 5% can be a reasonable deadband in some circumstances; the question is whether increasing UGI Gas's deadband from 3% to 5% is appropriate when evaluated together with the Company's full WNA proposal and the evidentiary record in this case.

Q. Why is increasing the deadband not appropriate for UGI Gas?

A. The deadband level should not be evaluated in isolation. In this case, the Company made a proposal to move from a 15-year weather normal to a more current 10-year normal that better reflects more recent weather conditions, which should reduce the likelihood and magnitude of WNA surcharges or credits over time. In other words, the Company's proposal already narrows the circumstances in which the WNA will produce adjustments by improving the definition of "normal" weather- by moving from a 15-year weather normal to the 10-year weather normal. These facts were not present in the Columbia Gas 2025 Rate Case's evidentiary record, and the Commission made its determination without the benefit of any analysis on the impact changing the normal weather period would have on the function of the WNA and deadband. Adding a larger 5% deadband on top of the move to 10-year normal weather is not necessary as shown by my analysis.

[37] UGI Gas St. No. 11-R, pp. 45-46.

Q. How do you respond to I&E witness Cline's point that a 5% deadband captures "normal weather fluctuations"?[38]

A. Mr. Cline's statement does not resolve the issue, nor was it supported by any analysis. A deadband is not simply a meteorological judgment about what range of weather may be considered "normal." It is a ratemaking design choice that determines how much of the weather-related revenue and bill volatility remains unaddressed and is still borne as risk to customers and the Company. A 3% deadband already prevents minor weather variations from triggering WNA adjustments. Increasing the deadband to 5% would expand the range of deviations for which no adjustment is made, even when those deviations can still have meaningful bill and revenue effects that distort the revenue recovered away from the cost of service.

Q. Would increasing the deadband from 3% to 5% benefit customers?

A. Not necessarily, and I&E witness Cline has not demonstrated that it would. A larger deadband would reduce surcharges in some warmer-than-normal periods, but it would also reduce credits to customers in colder-than-normal periods. The recent colder-than-normal winter months illustrate this point: larger deadbands reduce the extent to which customers receive the benefit of WNA credits when actual weather is colder than the normal weather assumptions embedded in rates. In my review, the Company should make the adjustment from the 15-year normal to the 10-year normal and evaluate that change's impact, which

[38] I&E St. 3-SR, p. 5.

is expected to result in a more symmetrical set of WNA credits and collections, before layering on another significant change, i.e., increasing the deadband from 3% to 5%.

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 12-RJ

Rejoinder Testimony of
Brian J. Meilinger

Topics Addressed: **Low Income Issues**

Dated: June 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian J. Meilinger. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 12, on January 28, 2026, and rebuttal testimony, UGI Gas Statement No. 12-R, on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. The purpose of my rejoinder testimony is to respond to certain claims in the surrebuttal testimony of Office of Consumer Advocate ("OCA") Witness Colton (OCA St. 6SR) and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Witness Cicero (CAUSE-PA St. No. 1-SR).

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, attached to my testimony are UGI Gas Exhibits BJM-1RJ through BJM-3RJ.

II. RESPONSE TO OCA WITNESS COLTON

Q. OCA Witness Colton asserts that you set "the bar far too low for what the obligations of UGI Gas are" in assisting low-income customers and that the Company has been failing to meet its "statutory mandate for Universal Service Programs." OCA St. 6SR, at pp. 2-3, 5. Do you agree with this characterization?

A. No. Witness Colton is wordsmithing my rebuttal testimony regarding the "many" customers for whom UGI Gas has produced positive outcomes. The reality is that UGI Gas meets its obligations to assist low-income customers afford gas service (which Witness Colton recognizes is the applicable standard), while providing substantial relief to low-income customers. As demonstrated in my prior testimony, CAP enrollment has increased by 40% since 2018 (UGI Gas St. No. 12-R, at pp. 13-14), and LIURP participation has been near 100% of Commission approved budgets since 2022 (UGI Gas St. No. 12, at pp. 7-8). Additionally, Operation Share has provided nearly 12,000 Operation Share grants to low to moderate income customers since 2022. UGI Gas St. No. 12, at p. 8. Furthermore, the Company is continuing its targeted marketing and outreach efforts in order to drive increased participation on a year over year basis.

Q. Witness Colton asserts that you did not dispute various data points, which, according to him, show that UGI Gas is not meeting its "statutory objective" to assist low-income customers. OCA St. 6SR, at pp. 3-4. Please respond.

A. As I explained previously, and as will be further addressed in the Company's briefs, UGI Gas meets its statutory obligation to assist low-income customers. Additionally, Witness Colton is only looking at certain metrics and notably overlooks others, such as the year over year successes of the Universal Service Program enrollments. With that, it is not immediately clear to me if Witness Colton understands all the metrics that he is evaluating. For instance, he states that "UGI Gas has three times more low income customers in debt than residential customers." OCA St. 6SR, at p. 3. This statement is incorrect. The data provided in UGI Gas's response to OCA-4-31 shows 30,820 Confirmed Low-Income

(excluding CAP) residential accounts in arrears as of January 2026 compared to the 142,704 residential accounts in arrears for the same month and year in UGI Gas's response to OCA-4-30. Copies of those discovery responses are attached as UGI Gas Exhibits BJM-1RJ and BJM-2RJ, respectively.

Q. Witness Colton claims that "the Company does fail to do all it can, and does, indeed, create barriers" to LIHEAP participation. OCA St. 6SR, at pp. 4-5. Do you agree?

A. No. The Company does not create barriers for LIHEAP participation. Witness Colton provides no meaningful evidence of this assertion in his surrebuttal. Instead, he criticizes me for stating that UGI Gas "facilitated" LIHEAP grants. The use of this terminology is how I describe the process of working with the Department of Human Services ("DHS"). When the DHS sends UGI Gas its LIHEAP customer vouchers, the Company uses this information to accurately post the information to the correct customer accounts. This process spans several months, typically from November through April, and involves significant resource and IT system commitments to ensure that the millions of dollars in LIHEAP assistance are accurately applied to the correct customer accounts.

In addition, Witness Colton is incorrect when he claims that the Company's LIHEAP grant figure of 109,000 is "suspect." *See* OCA St. 6SR, at pp. 4-5 note 7. The 109,000 figure refers to the number of LIHEAP grants, while the 72,659 that Witness Colton cites is the number of unique customers receiving a grant. Since it is possible for customers to receive more than one grant, the number of grants is higher than the number of customers participating.

Q. Witness Colton argues that your "extensive argument about how well UGI Gas is doing to provide 'a concerted focus on continued marketing and customer outreach to increase CAP enrollment' . . . misses the point," because "aside from CAP enrollment, the Company has a responsibility to provide certain protections . . . to 'confirmed low-income customers.'" OCA St. 6SR, at p. 6. Please respond.

A. My response about the efforts UGI Gas has undertaken to increase CAP enrollment (UGI Gas St. No. 12-R, at pp. 7-8.) does not miss the point. Rather, it addresses the claims raised in Witness Colton's testimony that UGI Gas does not do enough to engage low-income customers for enrollment in CAP. Regarding Witness Colton's claim about identifying confirmed low-income customers, as previously stated in my direct testimony (UGI Gas St. No. 12, at pp. 14-15) and in accordance with Paragraph 67(a) of the UGI Gas 2025 Rate Case Settlement, the Company maintains that it is compliant with the Commission's regulations at 52 Pa. Code § 62.2, which defines a "confirmed low-income residential account" to include "[a]ccounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds, self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon ratepayer or occupant contact prior to termination)." However, 52 Pa. Code § 62.2 also defines a "low-income customer" as "[a] residential utility customer whose gross household income is at or below 150% of the Federal poverty guidelines. Gross household income does not include the value of food stamps or other noncash income."

Q. Witness Colton disputes how you characterized OCA's discovery response regarding SNAP income eligibility, claiming that you have "deceptively represent[ed] the response." OCA St. 6SR, at pp. 6-8. Please respond.

A. I strongly disagree with Witness Colton's claim that I was intentionally deceptive when addressing his circular discovery response on SNAP eligibility and how that might be useful for CAP enrollment. *See* UGI Gas Exhibit BJM-12R (OCA Response to UGI-III-1). He asserts that the evidence of "SNAP participation would create a reasonable expectation that a UGI Gas customer is low-income," and while such evidence "may not be sufficient to certify income for purposes of CAP enrollment," the "PUC's regulations regarding Confirmed Low-Income status does [sic] not require that." OCA St. 6SR, at p. 8. However, I am advised by counsel that the Commission's regulations state that "[a]n applicant is confirmed to be eligible for a customer assistance program by the public utility if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the public utility's customer assistance programs." 52 Pa. Code § 56.32(e) (emphasis added). Therefore, the standard is not whether there is a "reasonable expectation" that they qualify, but instead, whether the applicant provides documentation or other information attesting to their eligibility.

Q. Witness Colton claims that it was not "reasonable" for you to "assert that more than three-of-five LIHEAP recipients" assign "LIHEAP to their secondary heating provider." OCA St. 6SR, at pp. 8-9. Do you agree?

A. No. Witness Colton misrepresents my testimony. I made no such statement that "more than three-of-five LIHEAP" recipients assign LIHEAP to their secondary heating provider. In my rebuttal testimony (UGI Gas St. No. 12-R, at p.20), I simply stated that it is possible that many of these customers "may" have received LIHEAP through their Electric Distribution Company and would, therefore, not be eligible to receive LIHEAP for their UGI Gas account. The Company would not have insight into this information because the DHS data sharing process only provides utilities with data on their own customers, not the customers of other utilities.

Q. Witness Colton asserts that when you used the term "screenshot of a COMPASS application," it is "not clear what [you] are referencing (or whether [you] even understand[] the proposal which [you are] objecting to" because "one does not apply for COMPASS." OCA St. 6SR, at p. 11. Please respond.

A. Although Witness Colton criticizes me for using the term "screenshot of a COMPASS application," he fails to realize that I was using the same terminology that he himself used multiple times in his direct testimony. Specifically, Witness Colton recommended that "UGI Gas, at a minimum, accept either a printout or a screenshot of the State of Pennsylvania's COMPASS application as adequate documentation to establish Confirmed Low-Income status." OCA St. 6, at p. 4 (emphasis added). Then, on page 54 of his direct testimony, Witness Colton stated, "My first recommendation, therefore, is that UGI Gas, at a minimum, accept either a printout or a screenshot of the COMPASS application as adequate documentation to established Confirmed Low-Income status." OCA St. 6, at p.

54 (emphasis added). Therefore, I was simply using the same terminology that Witness Colton was utilizing.

Q. Please respond to Witness Colton's claim that you "offer[ed] a series of misleading objections" to the "use of a customer's access to COMPASS in order to establish a reasonable expectation that the customer is low-income." OCA St. 6SR, at pp. 11-14.

A. Witness Colton's claim is incorrect. His recommendation to use a screenshot of COMPASS to establish Confirmed Low Income status is not needed and is unnecessarily complicated for the customer. A customer can simply self-certify their income and then they will be recorded in the Company's Customer Information System as Confirmed Low Income – there is no need to complicate the process and suggest that customers provide COMPASS documentation. Also, as I noted previously, Witness Colton keeps using the term "reasonable expectation," which appears nowhere in the applicable regulations.

Q. Do you agree with Witness Colton that you "misle[d] and mix[ed] up . . . the objections to what UGI Gas requires of a low-income customer in order for that customer to receive a deposit waiver or refund"? OCA St. 6SR, at pp. 14-16.

A. No. Witness Colton's claim is unsupported and should be rejected. He references my use of the "screenshot of a COMPASS application" language, which, as explained previously, is the same terminology that Witness Colton himself used in his direct testimony. Witness Colton also incorrectly asserts that I claimed he was wrong when he claimed that a customer must enroll in CAP to have their deposit waived. Witness Colton's incorrect claims on this point are further addressed below. Further, while Witness Colton maintains

that the Company's refund process is "inappropriate (and unlawful)," I am advised by counsel that the Company will address Witness Colton's position on this legal issue in its briefs.

Q. Witness Colton asserts that, contrary to your rebuttal testimony, he made no assertion that a customer must enroll in CAP to have their deposit waived. OCA St. 6SR, at p. 14. Did you say that was his position in your rebuttal testimony?

A. No. In my rebuttal testimony, (UGI Gas St. No. 12-R), I never asserted that Witness Colton stated in his testimony that a customer must enroll in CAP to have their deposit waived. In fact, I clearly stated that Witness Colton's position was "that UGI eliminate the requirement that a customer apply for CAP to establish eligibility for deposit exemption." UGI Gas St. No. 12-R, at p. 24, lines 23-25 (emphasis added). Moreover, when I was clarifying that customers do not need to enroll in CAP to receive the security deposit exemption under UGI Gas's process, my testimony was in response to Witness Cicero's commentary on whether or not customers need to enroll in CAP to receive the security deposit exemption.

Q. What is your response to Witness Colton's claim that "it is not possible . . . yet . . . to determine whether UGI Gas['s] actions taken pursuant to the 2025 settlement are adequate or meaningful"? OCA St. 6SR, at p. 18.

A. As stated in my rebuttal testimony, the Company's outreach efforts to engage with Mayor's Offices, facilitate additional WARM events, and launch the Low Income Customer Assessment Pilot are well underway and on track to meeting the provisions of the UGI Gas

2025 Rate Case Settlement. UGI Gas St. No. 12-R, at p. 28. Furthermore, while Witness Colton questions the relevance of directing him to UGI Gas Witness Adamo's rebuttal testimony on settlement compliance (OCA St. 6SR, at p. 17 note 27), he fails to see that the universal service-related settlement commitments, including the "provisions regarding universal service outreach and enrollment" he references, (*See* OCA St. 6SR, at p. 18.) are in the settlement compliance tracking documents provided by Mr. Adamo in his rebuttal and rejoinder testimony. *See* UGI Gas Exhibits DVA-2R and DVA-3RJ.

Q. Witness Colton concedes that he chose not to be involved "with the review of the Company's presentation of its customer outreach plan developed pursuant to the July 2025 Settlement of the 2025 UGI Gas rate case," but he believes that "[t]he testimony that gave rise to the Settlement should be the foundation of future discussions occurring pursuant to the Settlement." OCA St. 6SR, at pp. 18-19. Please respond.

A. To clarify my position, the Company does not state that Witness Colton needs to be present at each of the Company's Universal Service Advisory Committee ("USAC") meetings. However, Witness Colton criticized the Company's Low Income Customer Assessment and Outreach Pilot, while omitting in his testimony that he had opportunities to participate in the meeting or obtain a copy of the December 4, 2025 presentation. Unfortunately, he chose not to pursue either option. In addition, the Company diligently engaged with OCA and other USAC stakeholders on several rounds of feedback to provide a comprehensive marketing plan for this Pilot. These efforts, which Witness Colton fails to acknowledge in his direct testimony, demonstrate that the Company works collaboratively with interested stakeholders to develop and implement these initiatives. If Witness Colton had made an

effort to obtain this information, it likely could have avoided his criticism of the Low Income Customer Assessment and Outreach Pilot included in his direct testimony.

III. RESPONSE TO CAUSE-PA WITNESS CICERO

Q. Do you agree with CAUSE-PA Witness Cicero that you "blame[] low income customers themselves for not enrolling" in assistance programs? CAUSE-PA St. No. 1-SR, at p. 25.

A. No. There is no support for Witness Cicero's false and derogatory statement. My point was simply that because customers cannot be enrolled without their consent, customers will need to take some action to be enrolled in the programs. Also, in my position, I am strongly committed to operating and improving the Company's Universal Service Programs and helping customers receive assistance to better afford their natural gas service bills. I believe the Company's customers would be better served if the parties were to work together to develop solutions than to attack one another personally.

Similarly, nothing supports Witness Cicero's statement that "this position is problematic and representative of a culture that blames poor people for the decisions that UGI has made that result in unaffordable rates and make it difficult for eligible households to access available programs." CAUSE-PA St. No. 1-SR, at p. 25. Again, in my rebuttal testimony, I was simply clarifying that customers cannot be enrolled in a Universal Service Program without them taking some action. UGI Gas makes substantial efforts to educate its customers about the availability of assistance. Further, the Company strives to enroll as many eligible customers as possible. At some point, however, customers do need to take action to enroll in the programs. Making such an observation is not "blaming" customers for not enrolling in the programs.

Q. Please respond to Witness Cicero's purported issues with UGI Gas's survey questions regarding income screening. CAUSE-PA St. No. 1-SR, at pp. 26-28.

A. The income screening survey was developed by a UGI Gas employee who is a market research expert with over 25 years' experience (16 years in the utility industry), including survey development and analysis. The Company also utilized the survey management tool of a reputable vendor (Verint), which is a leader in voice and customer analytics, to field responses. Further, the survey was developed by the Company to gather insights into customer preference, regarding their willingness to provide income information to call center representatives. From my perspective, it appears that Witness Cicero wants to discredit the Company's survey methodologies simply because he does not like the results of the survey. On page 27 of his surrebuttal, he cites survey comments from seven respondents and relies on that information to allege that there is "a fundamental misunderstanding of the survey question and flaws in the process." Having highlighted only seven survey responses out of the 355 total responses (i.e., less than 2%), it is a stretch for Witness Cicero to imply that because of these comments, the entire survey was flawed.

Additionally, he fails to acknowledge one survey respondent's feedback that does not align with his income screening desires where the customer responded, "Please don't start asking callers for their income--just routinely ask if they'd be interested in learning more about UGI's income-based assistance. Then, if appropriate, share with them the program's income requirements. Never ask customers for personal information that you don't have a genuine need to know--it will only hurt your credibility as a utility provider and make people question whether they've called the wrong number and are speaking to a

scammer." UGI Gas Exhibit BJM-3RJ, p. 143 (UGI Response to CAUSE-PA-9-4). Although 72% of customers were either "very interested" (26%), or "somewhat interested" (34%) in learning more about income-based assistance programs, that does not mean that these customers are willing to share their income. The reality is that of the nearly 5,000 customers that were randomly surveyed, only 3 in 10 customers would be willing to share their income with the Company.

Q. Witness Cicero says that he is "<u>not</u> recommending that UGI ask every customer who calls its call center for a non-emergency call to provide their income information." CAUSE-PA St. 1-SR, at p. 28 (emphasis in original). Does that make sense given his proposed addition to the Company's call center script under his recommendation?

A. No. Witness Cicero clearly states on page 28 of his surrebuttal testimony that under his recommendation, he wants the Company to "provide the following statement (or something similar) on all calls for customers who call their call center for non-emergency calls and for new and moving customers: *UGI offers reduced rates and other assistance for income qualified customers. Would you like to provide your household income information to see if you qualify?*" That is obviously a statement asking the customer to provide their income information in exchange for information on assistance.

Furthermore, Witness Cicero made it abundantly clear in his direct testimony that he wants income screening on <u>all</u> non-emergency phone calls. Specifically, he recommended that UGI Gas be required to: (1) "[s]creen all new and moving customers for income level at the time their service is established and ask whether they would like information about income qualified programs that may reduce their rate"; (2) "[s]creen

existing customers for household income level on any non-emergency calls and inquire whether there have been any updates to household income information"; and (3) "[d]evelop a process for routine income screening through UGI's online account portal." CAUSE-PA St. No. 1, at p. 73 (emphasis added).

Finally, the Company already requests income and occupancy during all inbound calls regarding past due notices and nonpayment service disconnections. This practice is designed to ascertain the caller's eligibility for the Company's Universal Service Programs. If, based upon their stated income and household occupancy, the caller appears to be eligible for CAP, the caller is referred to a Community-Based Organization ("CBO") and is solicited for enrollment. If the caller already had their income verified, enrollment into CAP is expedited and facilitated during the call.

Q. Witness Cicero claims that "[i]t is difficult to imagine" that it would be expensive to implement his recommendation or cause customer frustration or confusion, as "UGI has provided no information about what the cost to implement this additional question would be, how it would affect call times, or why it would confuse or frustrate customers." CAUSE-PA St. No. 1-SR, at p. 29. Please respond.

A. The recommendation for income screening is CAUSE-PA's proposal, and I have been advised by counsel that CAUSE-PA bears the burden of proof on whether it should be adopted. Also, when asked in discovery what analysis CAUSE-PA has performed on this recommendation, Witness Cicero responded that he performed no analysis on any of the following critical items:

1. A "customer's willingness to provide income information on calls when income information is not required to address the UGI Gas customer's inquiry";

2. "[T]he potential impact to UGI Gas's customer satisfaction that might result from asking customers for income information on any non-emergency calls, even if the topic is not related to billing or credit";

3. "[T]he potential impact to the Company's call center department's average handle time to 'routinely screen existing customers for household income level on any non-emergency calls – and inquire whether there have been any updates to household income in-formation already noted on accounts";

4. The "cost impacts that may arise due to increased call center average handle time to perform income screening"; and

5. "[T]he IT costs to enhance the UGI online account portal to perform routine income screening."

UGI Gas Exhibit BJM-9R (CAUSE-PA Response to UGI-I-8).

Finally, the average call handle time would increase by, at a minimum, the amount of time it takes for the customer service representative to read the income screening script, and for the customer to respond. The average handle time would increase even further if the customer has questions or needs to provide income information. Increases in call times require the Company to hire additional customer service representatives to meet call performance standards. Yet, Witness Cicero failed to perform any analyses on these points. Thus, this proposal lacks support and should be rejected.

Q. Does the Company have any proposals in light of the testimony of Witnesses Colton and Cicero?

A. Yes. To the extent that the Commission believes that OCA and CAUSE-PA have identified inadequate enrollment in CAP as a key affordability issue, the Commission should grant UGI Gas up to $3 million to fund a dedicated advertising campaign promoting the Company's low-income programs.

IV. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 13-RJ

Rejoinder Testimony of
Daniel V. Adamo

Topics Addressed: **Call Center Performance**
Settlement Compliance

Dated: June 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Gas?

A. Yes, I submitted my rebuttal testimony, UGI Gas Statement No. 13-R on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain claims made by Office of the Consumer Advocate ("OCA") Witness Barbara Alexander in her surrebuttal testimony, OCA Statement 5SR.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, I am sponsoring UGI Gas Exhibits DVA-1RJ through DVA-3RJ.

II. CALL CENTER PERFORMANCE

Q. Have you reviewed Witness Alexander's Surrebuttal Testimony?

A. I have.

Q. Witness Alexander asserts that the information in Table 1 of your rebuttal testimony is different from the information provided in discovery. OCA St. 5SR, at pp. 4-5. Do you have a response?

A. Yes. UGI Gas timely responded to the "[a]dditional discovery" about "the underlying basis for the change in results," which was "pending" at the time of Witness Alexander's surrebuttal testimony. OCA St. 5SR, at p. 5. As explained in that response, a copy of which is attached as UGI Gas Exhibit DVA-1RJ, the Company discovered a discrepancy in the 2023 calendar year abandonment rate when submitting the requested workpapers for Table 1 in my rebuttal testimony on May 18, 2026. Specifically, the volume of abandoned calls was found to be inadvertently included twice in the value of calls received for calendar year 2023 and not adjusted for in the calculation of abandonment rate. On May 20, 2026, the Company provided a supplemental response to OCA-3-1(a), corrected the calls received and the resulting abandonment rate. The Company also followed up with the Commission's Bureau of Consumer Services ("BCS") about the reporting error, and the data has been corrected in BCS's system.

Q. What is your response to Witness Alexander's discussion of call center performance results? OCA St. 5SR, at pp. 4-6, 10-11.

A. Although Witness Alexander states that she cannot conduct a comprehensive analysis on the Company's compliance with 2025 Rate Case Settlement items focused on customer service commitments, I have demonstrated that the Company has complied fully with the items due to date and is on track to meet all required deadlines remaining.[1]

Additionally, I would like to focus on the abandonment rate metrics that Witness Alexander references on page 6 of her surrebuttal testimony, where she states:

[1] Also, in Section III, *infra*, I provide an updated version of the compliance tracker from my rebuttal testimony, which shows the most current information on the Company's compliance actions under the 2025 Gas Rate Case Settlement. As seen in that document, UGI Gas remains on track to meet all of its obligations.

> The annual average Abandonment Rate increased from 4% in 2024 to 4.7% in 2025. This data confirms that customers experienced poor service in several months, a pattern that was also reflected in 2024 data. Finally, while not required by the prior settlement, UGI Gas' performance is below that of other Pennsylvania natural gas utilities, a performance that should be taken into account in the base rate case results and supports my recommendation for the call center performance results that should be required in this base rate case. Mr. Adamo's attempt to present data to show a different result or excuse their actual results should be rejected.

OCA St. 5SR, at p. 6.

I disagree with these statements. First, the most recent of the Commission's Customer Service Performance Reports is for 2024.[2] That report shows the Company's call abandonment rate is 4%. The value mentioned as the basis for the Company's 2024 baseline metrics for call abandonment rate is truncated, rounded, or both in the Commission's report. The report does not show the value in tenths of a percent. The Company's call abandonment rate for 2024 out to the tenths decimal place was 4.4%. Witness Alexander compares the 2024 value of 4% to the 2025 abandonment rate of 4.7% as a decline in customer service. The comparison should be 4.4% versus 4.7% to be inclusive of the tenths of a percentage. Whether using Witness Alexander's incorrect value of a 0.7% variance or the actual 0.3% variance in abandonment rate from 2024 to 2025, this tiny difference is not an indication of poor or degrading performance. Classifying the Company's performance as poor based on a less than 1% variance on a volume of close to 1.5 million calls received in a year is unfair.

In further support of its position regarding the variance year over year and how the Company continues to perform at an adequate level, 2025 was a unique year. The federal

[2] *See* "2024 Customer Service Performance Report," PA. PUB. UTIL. COMM'N (Dec. 2025), *available at* https://www.puc.pa.gov/media/3762/2024-customer-service-performance-report-final.pdf ("2024 Customer Service Report").

government shutdown occurred as the Company approached the winter collections moratorium. This left the Company's most vulnerable customers without access to the very critical LIHEAP funds they needed. In UGI Gas Exhibit DVA-2RJ, I performed an additional analysis showing the impacts of the federal government shutdown, and highlighting those impacts on operations in October and November of 2025. In order to respond to this unprecedented event, the Company was required to pivot and provide additional training to call center representatives in October and to deploy those new processes in November during a very high-volume call period. These actions were critical in swiftly helping customers going into the winter who were behind on their gas bills and could not utilize LIHEAP to keep their gas service active through winter. The results of these efforts were detailed on pages 10-11 of UGI Gas Witness Meilinger's direct testimony. Providing this support to customers in need placed an unanticipated strain on customer service resources during the early winter time period.

As seen in UGI Gas Exhibit DVA-2RJ, there was an increase in call handle time year over year in the October and November period due to addressing customers' needs that were exasperated by the federal government shutdown. UGI Gas was on track excluding October and November to perform better in 2025 than 2024 when looking at percentage of abandoned calls. Although call volume was slightly higher in these two months, the amount of time the Company's representatives were on the phone with customers was significantly longer. In those 2 months, they spent an additional 3,825 hours supporting those customers in need versus the prior year.

Also, UGI Gas's customer satisfaction scores during the months of October and November 2025 exceeded the scores received from customers surveyed during the same

months in 2024. Table 1 below highlights customers' view of customer service was still at a high level despite the slight increase in abandonment rate.

Table 1

Month	2024 Customer Satisfaction Score (1-10 Scale with 10 being highest score)	2025 Customer Satisfaction Score (1-10 Scale with 10 being highest score)
October	8.97	9.10
November	8.85	8.90

In addition, Witness Alexander's comment about UGI Gas's performance relative to its peers is inaccurate when looking at multiple reporting metrics provided in the 2024 Customer Service Report.[3] In my rebuttal testimony, I included UGI Gas Exhibit DVA-3R, which highlighted the Company's performance data for 2024 compared to other natural gas utilities' data for the same period in 2024. It is inappropriate to compare UGI Gas's 2025 data to the other natural gas utilities' 2024 statistics. A proper analysis would compare data for the same time periods to evaluate the Company's performance. For example, Tables 2-4 below extracted from the 2024 Customer Service Report highlight some key areas that conflict with Witness Alexander's statement that the Company is performing below other natural gas utilities.

[3] *See* note 2, *supra*.

Table 2 (Page 17 of 2024 Customer Service Report)

NGDC Survey Results – Ease of Reaching the Company – 2022-2024

Company	Satisfaction with Ease of Reaching the Company		
	2022	2023	2024
Columbia	85%	81%	86%
NFG	87%	86%	85%
Peoples	84%	84%	86%
PGW	74%	84%	82%
UGI Gas	82%	80%	86%
Industry Average	**82%**	**83%**	**85%**

Table 3 (Page 25 of 2024 Customer Service Report)

NGDC Survey Results – Representative's Handling of Contact – 2022-2024

Company	Satisfaction with NGDC Representative's Handling of Contact		
	2022	2023	2024
Columbia	93%	91%	91%
NFG	92%	91%	90%
Peoples	94%	91%	90%
PGW	91%	92%	90%
UGI Gas	90%	91%	91%
Industry Average	**92%**	**91%**	**90%**

Table 4 (Page 30 of 2024 Customer Service Report)

NGDC Survey Results – Overall Satisfaction with Contact – 2022-2024

Company	Overall			Credit/Collection			Other		
	2022	2023	2024	2022	2023	2024	2022	2023	2024
Columbia	89%	87%	89%	90%	85%	89%	89%	88%	89%
NFG	89%	88%	87%	88%	86%	84%	89%	89%	88%
Peoples	91%	89%	88%	89%	91%	88%	91%	88%	87%
PGW	86%	87%	86%	88%	88%	86%	91%	86%	86%
UGI Gas	86%	83%	88%	93%	80%	87%	87%	83%	88%
Industry Average	**88%**	**86%**	**87%**	**89%**	**86%**	**87%**	**88%**	**87%**	**88%**

III. SETTLEMENT COMPLAINCE

Q. OCA Witness Alexander responds to your rebuttal testimony regarding the Company's compliance with the obligations under the 2025 Gas Rate Case

Settlement. *See, e.g.*, OCA St. 5SR, at pp. 2-7. Do you have any updates to the status of the Company's completion of its compliance obligations?

A. Yes. Please see the updated status of the Company's progress with its compliance with customer service obligations from the 2025 Gas Rate Case Settlement in UGI Gas Exhibit DVA-3RJ.

IV. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 15-RJ

Rejoinder Testimony of
Jessica R. Rogers

Topics Addressed:

Overview of Case
Affordability Concerns
Policy Considerations

Dated: June 1, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jessica R. Rogers. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my rebuttal testimony, UGI Gas Statement No. 15-R, on May 13, 2026. I did not sponsor direct testimony in this proceeding.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA"), primarily by OCA Witness Deupree (OCA Statement 1SR), and the Coalition for Affordable Utility Service and Energy Efficiency in Pennsylvania ("CAUSE-PA"), specifically by CAUSE-PA Witness Cicero (CAUSE-PA Statement No. 1-SR) regarding the facts and circumstances driving the Company's rate relief and how those facts and circumstances should be analyzed alongside the affordability of the Company's rates.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No.

II. OVERVIEW OF THE COMPANY'S REJOINDER CASE AND FINAL POSITIONS

Q. Based upon your review of the surrebuttal testimony submitted in this proceeding, and the Company's rejoinder testimony, what are the major issues that remain to be resolved in this case?

A. From the outset, this case focused on a limited number of issues and was driven by the necessary capital investments planned by UGI Gas in the Fully Projected Future Test Year ("FPFTY"). Over the course of this case, the Company has reduced its claim by approximately $8.5 million to reflect adjustments to certain Operations and Maintenance ("O&M") expenses. However, at no point in this case have the parties challenged the necessity of the $468 million of the Company's planned capital investments to improve the safety and reliability of its infrastructure. Similarly, there are no disputes as to the necessity, reasonableness, or prudence of the identified capital expenditures incurred to provide safe, reliable, and reasonable service to its customers. Furthermore, the O&M disputes in this proceeding are extremely limited and not concerned with the reasonableness or prudency of the amount of costs incurred by the Company, but simply whether those reasonable and prudent expenses should be recovered in rates. As a result of the Company's updates to its revenue requirement that are summarized by UGI Gas Witness Hazenstab (UGI Gas Statement No. 2-RJ) and discussed in greater detail by other Company witnesses, at this point, the only contested revenue issues that remain are summarized in the table below:

Issue	UGI	I&E	OCA
Capital Structure	Actual 46% debt/54% equity	Actual 46% debt/54% equity	Hypothetical 51% debt/49% equity
Return on Equity	10.75%	9.81%	8.80% or 8.4%
Depreciation	Equal Life Group	Equal Life Group	Average Life Group ($20M disallowance)
Collections Expense		Accepts Company position	$3.01M disallowance
PUC Assessment		Accepts Company position	$1.80M disallowance
Rate Case Expense	1 year	2 years ($880,000 disallowance)	2 years ($880,000 disallowance)

The financial outcome of this case largely centers upon the appropriate depreciation methodology and the determination of a reasonable rate of return. On both of these issues, the alternatives presented by the parties are deficient, and for OCA in particular, reflect a rejection of long-standing Commission precedent regarding capital structure and depreciation that was affirmed as recently as December 2025.

Q. In your view, what does this mean for the Commission?

A. Given that no party has challenged the rate base inputs into the Company's revenue requirement, and many of the inputs that were disputed in the direct testimony filed by the parties in April have now been resolved, it is appropriate to conclude that the expenditures set forth in the Company's final, rejoinder accounting exhibit are just and reasonable, and therefore should not be adjusted further. In rejoinder, the Company's case reflects a baseline of capital investment and expenses necessary to continue to provide safe and reliable service to customers, to meet new customer demand, and to continue providing high-quality customer service, including substantial programs that assist low-income customers. The Company's acceptance of adjustments to the level of certain costs reflected

in rates is evidence of its willingness to (1) limit the disputed issues in this proceeding, and (2) accept the responsibility of managing those expenses.

Q. How should this influence the Commission's review of other issues?

A. The Company's case reflects the prudent management of the utility so that it can serve the public in a cost-effective manner. UGI Gas has addressed affordability considerations through many direct and tangible decisions that are reflected in this case, including managing the year-over-year increase in expenses, limiting or reducing certain costs where it was feasible to do so, and foregoing traditional and valid claims that it has sought (and been awarded) in past base rate cases for the time being in this instant case (e.g., incentive compensation; management performance adjustment). The Company also committed to a substantial multi-year increase in funding for Operation Share. In making a decision in this proceeding, the Commission should evaluate these actions to address affordability while simultaneously considering the long-term impacts on the Company's ability to cost effectively provide safe and reliable service in the future. On this last point, it is appropriate for the Commission to continue to take a long-term view of these issues, consistent with the long-term nature of UGI Gas's service, the long-lived nature of its infrastructure, and the multi-year commitments reaching out past the next decade that the Company has made to increase the safety and reliability of its system through the replacement of vintage materials.

III. REJOINDER REGARDING AFFORDABILITY ISSUES AND REGULATORY POLICY

Q. Did other parties respond to your rebuttal testimony regarding issues of affordability and regulatory policy?

A. Yes. Both OCA Witness Deupree and CAUSE-PA Witness Cicero submitted surrebuttal testimony in response to my rebuttal testimony.

Q. Please summarize the surrebuttal testimony of these witnesses.

A. Witnesses Deupree and Cicero both substantially mischaracterize the Company's arguments. Witness Cicero, in particular, asserts that the Company seeks to turn ratemaking into a simple math exercise,[1] seeks to avoid accountability around affordability impacts from rate increases,[2] and that only through denial of a rate increase would UGI Gas have "appropriate incentives" to improve its operations to achieve a fair rate of return.[3] To be clear, these statements are incorrect, as I will explain further in my testimony. Finally, both Witness Deupree and Witness Cicero argue that a lack of evidence of financial distress in this case should be considered by the Commission when evaluating OCA's and CAUSE-PA's no rate increase proposals.[4] This position must be rejected as being both inconsistent with long-standing precedent and contrary to sound public policy, as I will explain.

Q. Do you have any initial comments or responses to this testimony?

[1] CAUSE-PA St. No. 1-SR pp. 4-5.
[2] CAUSE-PA St. No. 1-SR, p. 14.
[3] CAUSE-PA St. No. 1-SR, p. 10.
[4] *See* OCA St. 1SR, at p. 6 (arguing the Commission should consider UGI Gas's lack of market distress in assessing the rate increase); CAUSE-PA St. 1-SR, at p. 12 (indicating that negative cash flow is "not a sign of financial distress").

A. Yes. OCA, CAUSE-PA and the Company (as well as other parties) all recognize that the Commission is permitted to consider and should consider the affordability of utilities' rates. However, the parties disagree as to how it should be considered and what resulting adjustments to rates are appropriately guided by that consideration. OCA and CAUSE-PA take the position that general affordability should be a threshold consideration, where any concerns at the macroeconomic level or as to a specific subset of a specific class of customers would bar any rate relief in its entirety, unless a utility evidences financial distress. The Company's position is that the Commission has always considered the affordability of rates, but has done so either through generic proceedings or, in the context of a rate case, on a wholistic evaluation encompassing rate design and revenue allocation, the additional programs and services offered by the Company, and ultimately in its allowed rate of return. The Commission's long-standing practice strikes the appropriate balance, because utilities are charged with providing service that is both safe and reliable, as well as affordable.

Q. Do you agree with Witnesses Deupree and Cicero that UGI Gas has not adequately considered affordability?

A. No, I do not agree. Contrary to the aspersions cast by OCA and CAUSE-PA witnesses,[5] the Company has taken a number of steps since its last rate case and in the context of this rate case to address the affordability of the service it provides to customers. From the outset of this case, the Company has made affirmative choices during each phase that show its consideration of affordability and in particular its focus on low-income customers. In

[5] *See, e.g.*, OCA St. 1SR, at pp. 3-4; OCA St. 6SR, at pp. 6-7; CAUSE-PA St. No. 1-SR, at pp. 17, 25.

addition to those actions set forth in my rebuttal testimony (which no party addressed in their surrebuttal),[6] the Company has proposed the following additional measures as a part of its rejoinder testimony in this proceeding:

- Withdrawing a substantial portion of its incentive compensation claim.
- Withdrawing the remaining disputed employee activity costs.
- Withdrawing the remaining disputed advertising costs.
- Proposing that the Commission approve funding that would provide the Company with the ability to implement a widespread advertising campaign about the Company's low-income programs.

Critically, while the record demonstrates that UGI Gas has successfully improved and increased participation in low-income programs in recent years, the Company agrees with OCA and CAUSE-PA that challenges remain related to the identification and enrollment of low-income customers in customer assistance programs that are important to understand and address. It is for this reason the Company invites the Commission to approve additional funding that will allow it to expand the reach of its messages to reach more vulnerable customers. Moreover, the Company is willing and able to continue to make further strides to improve in these areas, as evidenced by the substantial settlement on these issues in its last base rate case.

However, as explained by UGI Gas Witnesses Meilinger (UGI Gas St. No. 12-RJ) and Fang (UGI Gas St. No. 16-RJ), the attention warranted by these issues to examine and address them is simply ill-suited for a highly-complex base rate proceeding that must be resolved in a 9-month timeframe. Indeed, rather than being able to fulsomely engage with all interested stakeholders and collaborate regarding the issues presented and solutions to

[6] UGI Gas St. No. 15-R, at pp. 11-13.

the same in a proceeding tailored and focused upon those issues, certain of the testimony advanced by OCA and CAUSE-PA in this singular base rate case has regrettably devolved into mischaracterizations of the Company's position and ad hominem attacks that serve nobody's interests.

Q. Please respond to CAUSE-PA Witness Cicero's statement that utilities can simply move money around and do not need rate relief. [7]

A. This appears to have been in response to my testimony noting that Mr. Cicero had made an error with regard to the Company's earnings reports. Rather than acknowledging his error, Mr. Cicero appears to suggest that the substantial capital that is being spent by UGI Gas is nothing more than an accounting matter that can be remedied without any change in the revenue being recovered by the Company. This, of course, is not true and reflects a fundamental misunderstanding of utility economics. Capital expenditures are cash outlays, not mere accounting entries. The Company must maintain adequate cashflow to fund its capital program, because that capital supports payment to vendors supplying millions of dollars of materials and equipment, and to the employees and contractors that work in all conditions to ensure that service to customers remains safe and reliable. Rates that fail to provide sufficient revenue recovery do not simply produce an unfavorable variance on a financial statement; they impair the Company's ability to fund the very infrastructure investments that protect public safety and system integrity.

[7] CAUSE-PA St. No. 1-SR, p. 12.

Q. Please respond to CAUSE-PA Witness Mr. Cicero's claim that this case is merely about the Company's profits.[8]

A. This statement ignores the thousands of employees whose salaries and benefits are reflected in this case, the broad economic impact the Company's activities have on the health and welfare across its service territory and the Commonwealth generally, and the hundreds of thousands of customers that rely on the investments and expenses reflected in this case to deliver safe and reliable service. Given the voluminous testimony submitted by Witness Cicero on the topics of affordability, the sufficiency of the Company's low-income programs, the choice of rate design elements, and the critical public policies as applied through this case, his statement in his surrebuttal testimony that this case is merely about profits ignores the comprehensive universe of Company activities addressed in this case to focus on one litigated issue: the rate of return. Moreover, taking his argument to its logical conclusion, Witness Cicero assumes that the Commission's existing ratemaking process is insufficient to protect ratepayers, a proposition that is difficult to square with the Commission's well-established authority and long track record of fulfilling its statutory duties. The standard for a rate increase under Pennsylvania law is not financial distress, it is whether existing rates are just and reasonable. Section 1301 requires that rates be "just and reasonable," and the Commission's obligation is to set rates that allow a utility to recover its prudently incurred costs and earn a fair return on its investment. There is no statutory requirement, and therefore no Commission precedent, conditioning rate increases on a showing that a utility is in financial distress. Distress is not the standard; cost of service is.

[8] CAUSE-PA, St. No. 1-SR, pp. 4-5.

Q. Please respond to the arguments made by OCA Witness Deupree and CAUSE-PA Witness Cicero that cite UGI Gas's lack of financial or market distress as a reason why its rate proposals should be rejected.

A. I agree with OCA and CAUSE-PA that UGI Gas is not in financial distress. However, that is not, and should not be, the standard applied by the Commission in determining whether a rate increase is appropriate. The Company has been able to make prudent investments that make its system safer and more reliable because it has consistently been able to obtain the rate relief needed to fund that critical work while ensuring the Company has the opportunity to earn a fair rate of return on its investments. The rate relief provided in UGI Gas's rate cases funds good paying Pennsylvania jobs and customer service with high customer satisfaction, supports robust customer assistance programs (which, I note, have continuously evolved and improved as a result of engagement with stakeholders across a variety of proceedings, including base rate cases), and fuels business and industrial growth that supports Pennsylvania's economy. Rate cases reflect two sides of a coin: the steady, necessary and important investment in essential infrastructure that services the public must be coupled with steady, necessary, and reasonable rate relief that reflects the cost of serving customers. A failure on either side of this coin undermines the provision of safe and reliable service.

Steady rate relief has been recognized by the legislature and the Commission as a critical component to facilitate steady safety investments. In 2012, Pennsylvania had approximately 13,000 miles of cast iron and bare steel pipes, the replacement of which was

estimated to cost $12 billion and take decades to complete.[9] It was these very circumstances and the associated threat to public safety posed by vintage materials that led to the passage of Act 11, authorizing the FPFTY and the distribution system improvement charge ("DSIC") to provide the steady rate relief that would facilitate and expedite the decades' worth of replacement activities required. As of December 31, 2025, Pennsylvania had a total of less than 6,000 miles of cast iron and bare steel main – a reduction of more than 50%.[10] This substantial reduction in vintage materials, and the concurrent substantial increase in public safety, could not be accomplished if utilities were not provided adequate and timely rate recovery to support the sustained capital investment and were, instead, required to exhibit evidence of financial distress. The Commission has, as recently as its order in the Columbia Gas of Pennsylvania, Inc. rate case in December 2025, re-affirmed the importance of removing vintage materials on an accelerated basis. Timely rate relief is just as critical today as it was in 2012 to support accelerated replacement programs.

Q. Why is requiring financial distress as a condition for rate relief bad public policy?

A. In addition to being inconsistent with the Commission's legal obligations as part of the regulatory compact cited by Witness Cicero, requiring indications of financial distress would compromise a utility's ability to do critical work that serves the public. Prior to the point of financial distress, any prudently managed utility would take corrective steps, first

[9] Testimony of Robert F. Powelson, Chairman of the Pennsylvania Public Utility Commission, before the Pennsylvania House Appropriations Committee on February 27, 2012 https://www.legis.state.pa.us/WU01/LI/TR/Transcripts/2012_0043_0001_TSTMNY.pdf (last visited May 30, 2026).

[10] See, Pipeline and Hazardous Materials Safety Administration databases for cast/wrought iron showing 1,689 miles remaining, at https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Public%20Website/CI%20Miles/GD_Cast_Iron, and bare steel showing 4,226.58 miles remaining, at https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Public%20Website/_portal/GD_BARE_STEEL (last visited May 31, 2026).

and foremost of which would involve seeking rate relief; followed by (1) reducing any non-critical spending (e.g., charitable giving); and (2) eliminating headcount. Eliminating headcount would, in turn, slow the pace of improvements to the system, including the addition of new customers, stop the expansion of programs that would benefit the public, and erode the quality of customer service. Further, if a utility must have evidence of financial distress when it seeks a rate increase, it must then wait nine long months before it may experience any form of financial relief and only potentially see an improved financial position after the full FPFTY occurs. In the meantime, harm – potentially irreparable – may be done to the utility's facilities, employees, customers, and communities that rely on financially healthy utilities.

Finally, adopting a financial distress standard would ultimately produce the very outcome CAUSE-PA seeks to oppose - higher costs for ratepayers in the form of rate shock. A utility trending toward financial distress would face credit downgrades and higher borrowing costs long before any rate relief was granted, and deferred recovery of capital investment would accumulate into a backlog requiring recovery all at once, producing a revenue requirement far larger than incremental annual recovery would have generated. In other words, it costs far less to maintain a house than to rebuild it. The regulatory compact and the constitutional framework established in *Hope* and *Bluefield* exist precisely to prevent this scenario by maintaining utility financial health on a continuous basis, not as a crisis intervention mechanism triggered only after the damage is done. Protecting ratepayers means keeping the utility financially sound, not waiting until it is not.

Q. Do you have any other thoughts on the proposals advanced by both OCA and CAUSE-PA to provide no rate relief in this proceeding, or a rate decrease as advanced by OCA?

A. Yes. CAUSE-PA Witness Cicero cites to the Commission's decision in *Pa. Pub. Util. Comm'n, et. al v. Twin Lakes Utilities, Inc.*, Docket No. R-2019-3010958, (Order entered March 26, 2020) ("*Twin Lakes*"), and while I found this case to be illuminating, it appears to stand for the opposite of what Mr. Cicero advocates for in this proceeding. I reviewed this order, and this case involved a small, distressed utility (with approximately 110 customers) that had repeatedly failed to make necessary improvements to its water system and had a litany of service reliability and service quality issues, as well as a rate proposal that would have increased customer bills by orders of magnitude. Even though that utility was (in my view) apparently failing in its obligations to its customers, and even after the Commission discounted the authorized ROE to account for those service failures and to mitigate the immense rate impacts, the Commission still authorized a rate increase, with an approved ROE (9.23%) higher than the ROE calculated by OCA in this case (8.4% under the actual capital structure) or the implicit ROE that would be produced by both OCA and CAUSE-PA's proposal of no increase (7.70%). Given the serious customer service and safety issues in *Twin Lakes*, and for the reasons identified by UGI Gas Witness D'Ascendis, the Commission should view the positions advanced by OCA and CAUSE-PA in this proceeding as being inconsistent with the Commission's precedent or good public policy.

Q. Do either OCA or CAUSE-PA address the need for rate relief in the FPFTY due to the substantial capital investments identified?

A. No. Neither witness meaningfully addresses the point I raised in my rebuttal testimony that the substantial infrastructure replacement programs being undertaken by UGI Gas cause the Company to be cashflow negative, and that cash is required in order to run those programs, pay employees and contractors, and pay vendors supplying necessary materials. Further, they are critical of the frequency of base rate cases, and suggest that rate relief through base rate cases should only occur if there is evidence of financial distress. Financially distressed utilities—whether caused through imprudent management or a regulatory process that would deny utilities of appropriate cost recovery that is needed to meet the actual cost of service required for the provision of safe and reliable service—are good for nobody - Not the utility, its customers, stakeholders, or the Commission.

Q. Please respond to OCA Witness Deupree's and CAUSE-PA Witness Cicero's statements that statutory ratemaking authority in Pennsylvania shifts risks from utilities to their customers.

A. Both Witnesses Deupree and Cicero assert that statutorily approved mechanisms—the FPFTY and the DSIC, as well as the weather normalization adjustment ("WNA")—shift risk from the utility onto the ratepayer. I disagree with this characterization. The authorized ratemaking mechanisms in use by UGI Gas ensure the provision of safe and reliable service at a reasonable cost to the public. Each of these mechanisms is subject to careful review by stakeholders and the Commission, and is designed to allow utilities to recover prudently-incurred costs that have already been vetted by the Commission. What these mechanisms do not do is reduce the risk of recovery where a utility has acted imprudently, has exercised poor management decisions, or has incurred costs that are

otherwise inappropriate for inclusion in base rates. Said more succinctly, these mechanisms increase efficiency and improve the precision of the cost recovery process, allowing utilities to more effectively operate to serve the public while still maintaining all of the ratemaking risk associated with the disallowance of imprudent or unreasonable costs. Furthermore, while OCA and CAUSE-PA focus on these statutory mechanisms, they ignore other provisions of the Public Utility Code that clearly empower the Commission and stakeholders to challenge whether a utility is over-earning or otherwise including imprudent and unreasonable costs in its rates, and seek refunds of those amounts outside of a base rate case. Finally, the OCA and CAUSE-PA assertions do not recognize the myriad of risks the Company faces every day related to the specific execution and operational risks related to a sophisticated natural gas distribution system that must continually provide safe and reliable service.

Q. Contrary to the testimony of CAUSE-PA Witness Cicero,[11] how are UGI Gas's proposals in this proceeding responsive to the needs of its customers?

A. The record in this case demonstrates UGI Gas's dedication to cost-effectively meeting the needs of its customers. That evidence includes:

- Retirement of the last known mile of cast iron on its system in May 2026, marking a major safety milestone, and the continued accelerated replacement of other vintage materials.
- Effective management of expenses over time below the pace of inflation.
- Multi-year commitment to increase Operation Share funding up to $1,000,000, doubling the Company's annual donation.

[11] CAUSE-PA St. No. 1-SR, at p. 25.

- Voluntary actions in October/November 2026 to assist hundreds of vulnerable customers that otherwise would have been harmed by the lack of government funding of LIHEAP. This included an additional $500,000 Company donation to Operation Share.

- Growth in CAP program participation by 51% from 2018 through YTD May 2026.

- Increase in funding for LIURP by 84% since 2018.

- Evidence of steady or improved customer service metrics across many categories, including high customer satisfaction ratings.

- Proposed ROE below the mid-point of the proxy group, and no proposal of a management effectiveness adder.

- Withdrawal of approximately $8.5 million in claimed expenses that have been previously authorized by the Commission for inclusion in rates.

The Company is committed to continuous improvement in how it operates and in the quality of its facilities so that UGI Gas can meet the needs of its customers, but that continuous improvement has incremental costs, overwhelmingly costs that no party has opposed, that must be reflected in rates. UGI Gas's case in rejoinder strikes a balance between the interests of customers and the financial needs of the Company.

IV. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2025-3059523 et al.

UGI Utilities, Inc. – Gas Division

Statement No. 16-RJ

Rejoinder Testimony of
Cyndee S. Fang, Director
Atrium Economics, LLC

Topics Addressed: **Affordability**

Dated: June 1, 2026

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Cynthia S. Fang, and I am employed by Atrium Economics, LLC ("Atrium") as Director. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my rebuttal testimony, UGI Gas Statement No. 16-R, on May 13, 2026.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the surrebuttal testimony submitted by other parties in this proceeding concerning affordability, the role of targeted assistance programs, and the appropriate regulatory forum for evaluating broader questions related to program enrollment, affordability metrics, and potential program changes.

- Office of Consumer Advocate ("OCA")
  - Statement No. 1-SR – surrebuttal testimony of Michael W. Deupree ("Mr. Deupree"); and
  - Statement No. 6SR – surrebuttal testimony of Roger D. Colton ("Mr. Colton").
- Coalition For Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1-SR – surrebuttal testimony of Patrick M. Cicero ("Mr. Cicero").

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No, I am not.

II. AFFORDABILITY AND THE APPROPRIATE REGULATORY FORUM

Q. Mr. Colton, Mr. Deupree, and Mr. Cicero each contend, in different ways, that affordability is an important issue in this proceeding. Do you disagree with that premise?

A. No. I do not disagree that affordability is an important issue. To the contrary, my rebuttal testimony expressly recognized that many customers are experiencing real financial strain and that affordability concerns warrant careful attention. In that respect, there is substantial agreement across the parties that affordability matters. Where I differ from these witnesses is not on whether affordability is important, but on how the issue should be evaluated in this rate case and on what regulatory tools are most likely to produce meaningful and durable improvements for customers.

Q. If the parties broadly agree that affordability is important, what is the principal difference between your approach and the approach advanced by Mr. Colton, Mr. Deupree, and Mr. Cicero?

A. The principal difference is that the Company's approach, as presented in my rebuttal testimony and the testimony of other UGI Gas witnesses, provides the Commission with a more effective way to advance meaningful change on affordability issues. It recognizes the importance of affordability, while also recognizing that those issues deserve a focused and robust review that may be difficult to achieve in a rate case with many competing issues.

The record also demonstrates that this approach is more complete than the surrebuttal criticisms suggest. Mr. Colton questions my use of census-block-group median household income in the systemwide gas-burden analysis, but my rebuttal testimony also included a separate, customer-level Customer Assistance Program ("CAP") analysis using

verified income data for the subgroup most directly relevant to affordability policy. See OCA St. 6SR at 31-43; UGI Gas St. No. 16-R at 18-25. Similarly, Mr. Cicero does not present a separate quantitative analysis, but instead focuses on the limitations of the systemwide analysis for evaluating the most vulnerable customers, while my rebuttal testimony separately included a low-income CAP analysis demonstrating that CAP materially reduces customer burdens. See CAUSE-PA St. No. 1-SR at 17-23; UGI Gas St. No. 16-R at 18-25. Mr. Deupree's surrebuttal largely restates the macroeconomic and shared-burden themes from his direct testimony without presenting additional analysis. See OCA St. 1SR at 3-7. Later in my testimony, I will provide a detailed comparison of the strengths of my approach compared to Mr. Colton's analysis, which is the only other analytic framework provided as evidence in this proceeding for the Commission to evaluate.

In short, the Company's approach does not diminish the importance of affordability; rather, it addresses affordability using the tools best suited to the issues presented here. It provides systemwide context through a transparent and replicable methodology, supplements that analysis with a customer-level review using the Company's verified CAP income data, recognizes the importance of targeted assistance, and preserves a clear distinction between rate-case determinations and broader program-policy reform. In my view, that framework is more informative and more useful to the Commission than the broader, but less procedurally focused, approach advanced by the intervenors.

Q. Why do you believe a separate proceeding is needed if the goal is to move the needle on affordability in a meaningful way?

A. A separate proceeding is needed because the record demonstrates that the most consequential affordability questions extend beyond whether affordability matters. They include how affordability should be measured, which customer populations should be prioritized, what data are sufficiently reliable, what barriers limit program participation, and whether existing program structures should evolve. Those are important questions, but they warrant a more focused inquiry than a base rate case is designed to provide. They are substantive program and policy questions that warrant dedicated examination if the Commission seeks to produce meaningful improvements in customer outcomes.

The intervenors' own critiques underscore that point. Mr. Colton's surrebuttal focuses extensively on disputes over affordability metrics, income proxies, and methodological choices. See OCA St. 6SR at 31-40. Mr. Cicero likewise emphasizes enrollment gaps, the distinction between enrolled and unenrolled low-income customers, and the interaction between base rates and universal service program performance. See CAUSE-PA St. No. 1-SR at 15-23, 24-33. Those criticisms do not establish that the Company's rate request should be decided on a different basis. Rather, they demonstrate that broader affordability reform would require a more structured inquiry into program administration, data, and design than this base rate case can reasonably provide.

That is why the Company's approach is the more effective one. It identifies what can be concluded reliably on this record—namely, that affordability is important, that targeted assistance programs matter, and that CAP is effective for participating customers—while also recognizing that moving the needle further would require a

dedicated proceeding capable of addressing the broader issues directly and comprehensively. See UGI Gas St. No. 16-R at 24-30.

Q. What types of issues, in your view, would need to be examined in that separate proceeding?

A. At a minimum, a separate proceeding addressing affordability should examine three related categories of issues. First, there should be a more detailed assessment of customer hurdles to enrollment. As both Mr. Colton and Mr. Cicero emphasize, participation outcomes can be affected by screening, documentation, communication, referral practices, and broader administrative barriers. See OCA St. 6SR at 40-43; CAUSE-PA St. No. 1-SR at 23-33. Those are implementation questions that would benefit from focused review of customer pathways, program operations, and administrative feasibility.

Second, that separate proceeding would allow for a fuller and more robust examination of which metrics should be used to assess affordability and what data are available to support those metrics. That need is evident from Mr. Colton's detailed critique of my systemwide gas-burden analysis, including his objections to the use of census-block-group median household income and his preference for alternative affordability metrics. See OCA St. 6SR at 31-40. Whether one agrees or disagrees with those criticisms, they confirm that the parties are debating foundational methodological questions. A dedicated proceeding is better suited to resolve those issues consistently, transparently, and on a more fully developed evidentiary record.

Third, that proceeding would provide the appropriate forum to assess whether program redesign should be considered. My testimony does not suggest that the current

CAP is ineffective. To the contrary, the customer-level CAP analysis in my rebuttal testimony showed that CAP materially reduces gas burdens for participating customers. See UGI Gas St. No. 16-R at 21-25. Mr. Cicero's surrebuttal, however, argues that enrollment gaps, customer needs outside CAP, and broader affordability pressures may warrant additional or different measures. See CAUSE-PA St. No. 1-SR at 15-23. If parties wish to evaluate whether there should be more—whether through refinement, expansion, or complementary tools—that inquiry should occur in a single forum designed to examine program objectives, customer targeting, administrative tradeoffs, and funding implications comprehensively, rather than piecemeal in a base rate case.

Q. Does your position mean that the Commission should disregard affordability concerns in this case?

A. No. My position does not mean the Commission should disregard affordability concerns. It means that the Commission should address them in a manner consistent with the purpose of this proceeding and the tools available in this forum. In this rate case, affordability concerns provide important context, underscore the value of targeted assistance programs, and reinforce the importance of program effectiveness. But they do not alter the central question of whether the Company's proposed rates are supported by prudent costs, nor do they eliminate the need for a more focused, separate examination if the Commission wishes to address broader affordability questions in a way that is likely to produce durable and well-informed improvements for customers.

Q. In your view, what is the central methodological issue with the intervenor criticisms of your affordability analysis?

A. In my view, the central methodological issue is that the intervenor criticisms largely attack the limitations of the systemwide proxy analysis while giving insufficient weight to the fact that my testimony already included a second, verified-income customer-level analysis of the CAP population. That second study is not peripheral—it is the direct response to the principal critique they advance. See UGI Gas St. No. 16-R at 18-25.

As a result, the intervenors' methodology critique is incomplete. It treats the first study as though it were the entirety of the affordability analysis, when in fact the record contains two related studies serving two different purposes: a systemwide contextual study and a targeted CAP study using verified income. When those two studies are read together, the Company's approach is methodologically stronger than the intervenors suggest because it both provides territory-wide context and directly evaluates the low-income subgroup using customer-level income data.

For that reason, I continue to believe the Company's methodology provides the Commission with a sound and decision-useful framework for evaluating the affordability issues presented in this proceeding.

Q. How do you respond to the criticism that your systemwide analysis "tells us nothing"[1] about low-income customers or those facing the greatest hardship?

A. I do not agree with that criticism. The systemwide study was not presented as a stand-alone measure of low-income hardship, nor was it offered as the sole basis for evaluating

[1] CAUSE-PA St. No. 1-SR at 17.

affordability. It was presented as one part of a broader analytical framework. See UGI Gas St. No. 16-R at 15-18. The criticism is therefore incomplete because it isolates the first study while disregarding the second study that I also presented.

Specifically, my rebuttal testimony included a separate customer-level gas-burden analysis of CAP-enrolled customers using verified income data. See UGI Gas St. No. 16-R at 18-25. That second analysis was conducted precisely because a proxy-based systemwide study cannot provide the same degree of precision for the low-income subgroup as a verified-income customer-level analysis. In other words, the record already contains the direct empirical check that the intervenors claim is needed.

That is why I do not find it persuasive when Mr. Colton and Mr. Cicero focus their criticism almost entirely on the systemwide study while devoting limited discussion to the CAP analysis. See OCA St. 6SR at 40-43; CAUSE-PA St. No. 1-SR at 18-23. The CAP analysis is the targeted low-income affordability analysis. It demonstrates that CAP materially reduces gas burdens for participating customers and provides the most relevant record evidence concerning affordability outcomes for income-eligible participants. For that reason, the claim that my testimony "tells us nothing" about vulnerable customers is simply not correct.

Q. Mr. Colton proposes an alternative affordability methodology based on ZIP-code-level data and a weighted average burden calculation. Why do you believe your methodology is more informative and reliable for use in this proceeding?

A. My methodology is more useful and more reliable because it uses more detailed information, including information that is specific to UGI Gas's customer base, and shows

how customer burdens vary across the population. Mr. Colton's alternative approach is less helpful for that purpose. See OCA St. 6SR at 38-40.

First, his approach uses ZIP codes rather than census block groups. ZIP codes cover larger and more diverse areas, so they provide a less precise match between customer locations and local income conditions. Second, his approach uses average usage and average bill data, which removes the customer-level differences that are important to understanding affordability. Third, his approach produces a single average burden figure for the service territory, rather than showing the full distribution of customer burdens. As a result, it cannot show how many customers are above particular burden thresholds, identify the upper end of the burden distribution, or distinguish among different customer groups in the way my analysis does. See UGI Gas St. No. 16-R at 16-18, 21-25.

For those reasons, the Company's methodology is better suited to this case. It uses customer-level annual bill data, the most detailed publicly available income proxy for the systemwide study, and verified customer-level income for the CAP subgroup. In that way, it provides both a systemwide view and a direct low-income companion study, which Mr. Colton's proposed alternative does not provide.

Q. Mr. Colton also contends that effective buying income or tax-adjusted income should be used instead of median household income. Do you agree?

A. No. I do not believe a tax-adjusted or "effective buying income" measure is better for this analysis. My use of gross household income is consistent with the way utility affordability is usually evaluated. CAP eligibility, federal poverty guidelines, and common affordability benchmarks - including the Commission's Home Energy Affordability for Low Income

Customers study provided in docket number M-2017-2587711[2] - are generally based on gross income, not an after-tax income estimate. See UGI Gas St. No. 16-R at 18-25.

Using effective buying income would also require many additional assumptions that are not directly available at the block-group level, such as household size, tax status, credits, deductions, and other tax-related factors. Those assumptions would add complexity and uncertainty. By contrast, gross median household income is a Census measure that can be applied consistently and transparently across the study population.

In addition, even if after-tax income were modeled, it is not expected to change the main result of my testimony: lower-income customers face higher burdens than the general customer population, and CAP materially reduces those burdens for participating customers. That overall pattern would remain the same due to the fact that low-income households' pre- and post-tax-adjusted incomes typically do not experience wide margins of change. In my view, the gross-income approach is clearer, more consistent with existing program standards, and better suited to the concerns raised in this proceeding.

Q. Mr. Colton criticizes your exclusion of zero-income CAP customers from the verified-income burden calculation. Why was that exclusion appropriate?

A. Zero-income customers are important and were not left out of the affordability discussion. My rebuttal testimony specifically identified them and reported that 1,396 of the 13,774 CAP-enrolled customers in the dataset—about 10 percent—had verified annual income of $0. See UGI Gas St. No. 16-R at 19-21. Those customers were discussed in the testimony;

[2] https://www.puc.pa.gov/pcdocs/1602386.pdf.

they were excluded only from the energy-burden calculation because that specific ratio cannot be calculated when income is zero.

That is because gas burden is defined as annual gas bill divided by annual household income. When verified annual income is zero, the ratio is mathematically undefined. See UGI Gas St. No. 16-R at 20-22. This is not a judgment about whether those customers matter. It is simply a mathematical limitation of the metric itself. As noted in my rebuttal testimony, the Commission's Home Energy Affordability for Low Income Customers study recognized this same limitation. See UGI Gas St. No. 16-R at 20-22. That study explained that zero-income households present a measurement challenge for burden analysis because the standard burden ratio cannot be calculated in the usual way when income is zero. See Home Energy Affordability for Low Income Customers in Pennsylvania, Docket No. M-2017-2587711, at 17-18.

In short, zero-income customers were not excluded from the discussion of affordability. They were identified and specifically discussed in the record. They were excluded only from the calculation of energy burden because the standard burden ratio cannot be computed for them.

Q. Mr. Colton and Mr. Cicero both criticize the Company's program enrollment outcomes and argue that more should be done to increase participation. Do you disagree that enrollment matters?

A. No. I do not disagree that enrollment matters. To the contrary, my testimony recognizes that participation is critical to whether targeted assistance programs achieve their intended affordability outcomes. Where I differ from Mr. Colton and Mr. Cicero is not on the

importance of enrollment, but on the regulatory conclusion that should be drawn from the existence of enrollment gaps. In my view, those gaps do not establish that the Company's proposed base rates are unjust or unreasonable. Rather, they point to questions concerning screening, outreach, recertification, customer communication, and program administration that may be better addressed through more focused review in the appropriate forum. See OCA St. 6SR at 40-43; CAUSE-PA St. No. 1-SR at 23-33; UGI Gas St. No. 16-R at 27-30.

Q. Why do you believe questions about enrollment barriers are better addressed in a separate program-focused review than in this base rate case?

A. Because enrollment barriers are operational and administrative in nature. They involve questions such as how customers are identified, how information is communicated, what documentation is requested, how recertification is managed, how referrals are handled, and what tradeoffs exist between administrative simplicity, customer burden, and program integrity. Those issues may be important, but they are not and will not be resolved by adjusting the revenue requirement in a base rate case. More fundamentally, affordability challenges are driven by low income, economic hardship, and barriers to program participation are not solved by changing the revenue requirement alone. In my view, they are better addressed in a proceeding designed to examine program operations directly, with the appropriate record on implementation feasibility, customer experience, data systems, and coordination across assistance mechanisms. That type of focused review is more likely to produce practical and durable improvements than attempting to address those issues indirectly through a base rate determination.

Q. Does the current record support the conclusion that CAP is ineffective or that the Commission should redesign the program in this proceeding?

A. No. In my view, the current record does not support the conclusion that CAP is ineffective. To the contrary, the verified-income CAP analysis in my rebuttal testimony showed that CAP materially reduces gas burdens for participating customers. See UGI Gas St. No. 16-R at 21-25. That is a strong indication that the program is functioning as an important affordability tool for those it reaches. The fact that parties may wish to examine whether there should be additional measures, modified features, or complementary tools does not convert that record into evidence that the current program is failing. Rather, it suggests that future evaluation of possible refinements may be appropriate in a forum designed to assess program design comprehensively.

Q. How do enrollment and potential program design issues fit within your overall affordability position in this case?

A. They fit within it directly. My position has been that affordability is an important issue, that targeted assistance is the appropriate regulatory tool for addressing income-based hardship, and that the record confirms CAP is an effective mechanism for participating customers. At the same time, the record also indicates that questions concerning enrollment barriers, the choice of affordability metrics, and whether any program refinements should be considered are broader issues that warrant more focused review than this base rate case can provide. In my view, that is not a reason to discount affordability concerns. It is a reason to address them using the most appropriate and effective regulatory forum. Finally,

an individual utility may be able to have some limited impact on economic hardship for its customers, particularly for low-income customers, but it cannot resolve socioeconomic disparities; nor should the Commission deviate from establishing an appropriate cost for providing safe and reliable service solely because of external socioeconomic disparities.

III. ROLE OF CAP AND POTENTIAL PROGRAM EVOLUTION

Q. How does your analysis of CAP inform your views on affordability and on possible future program changes?

A. My analysis supports two conclusions, both of which reinforce the strength of the Company's approach. First, CAP is an important and demonstrably effective affordability tool for customers who participate in it. The customer-level analysis in my rebuttal testimony used verified CAP income data and showed that CAP materially reduces burdens for enrolled customers. See UGI Gas St. No. 16-R at 18-25. That is significant because it responds directly to one of the central intervenor criticisms of my broader systemwide analysis—namely, that a proxy-based systemwide metric may not fully capture low-income customer conditions. By separately examining CAP customers using verified income data, my testimony addressed that concern directly and provided a targeted analysis of the customer group most relevant to affordability policy.

Second, the existence of a meaningful and effective targeted program does not preclude future evaluation of whether additional measures should be considered. Rather, it provides an important starting point: the current CAP is providing measurable benefit, and any discussion of future modifications or complementary tools should take that demonstrated effectiveness into account. This is another respect in which my approach is helpful to the Commission. Mr. Colton and Mr. Cicero both rely on my CAP findings to

support broader policy arguments, but those same findings also indicate that targeted assistance is an important mechanism for addressing income-based hardship and that related questions may be appropriately examined through focused program review. See OCA St. 6SR at 40-43; CAUSE-PA St. No. 1-SR at 18-23.

Q. Does acknowledging that additional program options might be worth evaluating undermine your testimony in support of the Company's position in this proceeding?

A. No. Those points are entirely consistent. Recognizing that a program can be effective today while also being open to future evaluation or refinement is not a contradiction. In this case, my testimony supports the Company's position that affordability is important, that targeted assistance is the appropriate regulatory tool, and that broader questions about enrollment barriers, measurement, and possible program evolution should be examined in a proceeding designed for that purpose. That is, in my view, a more practical and more effective path than attempting to use this base rate case to resolve broader affordability-policy questions that extend beyond the prudence of the Company's costs and the appropriate level of rate relief.

IV. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3059523
v.	:	
	:	
UGI Utilities, Inc. – Gas Division	:	
	:	

DIRECT TESTIMONY

OF

Michael Deupree

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 1

Date Served: April 13, 2026

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Senior Research Consultant with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the University of Kansas in Lawrence, Kansas. I began my professional career with the Staff of the Kansas Corporation Commission in 2008 while in graduate school conducting analyses of topics related to energy and economy as a Research Assistant, eventually being promoted to a Research Analyst and later Senior Research Economist after graduation. I left the Kansas Corporation Commission to take a position with ACG in late 2011, where I have been promoted to positions of increasing responsibility since, including my current position which I started in Spring of 2025. Appendix A provides my professional resume, which includes a listing of my publications, presentations, pre-filed expert witness testimony, expert reports, and expert legislative testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Pennsylvania Office of Consumer Advocate ("OCA") to address matters related to the general rate case filed by UGI Utilities, Inc. – Gas Division ("UGI-G" or the "Company"). I specifically have been asked to provide an overview of this case from a public policy perspective, and review issues related to alternative regulation and the Company's proposed Allocated Class Cost of Service Study ("ACOSS") and associated rate design.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits MWD-1 through MWD-8.

- Exhibit MWD-1: Commission Alternative Regulation Consideration (§ 69.3302)
- Exhibit MWD-2: Survey of Approved Pennsylvania Natural Gas WNA Mechanisms
- Exhibit MWD-3: Summary of Results of Company's Proposed ACOSS
- Exhibit MWD-4: Summary of Results of ACOSS Using Seaboard Allocation
- Exhibit MWD-5: Summary of Results of Alternative ACOSS
- Exhibit MWD-6: Summary of Company's Proposed Revenue Allocation
- Exhibit MWD-7: Summary of Results of Alternative Revenue Allocation
- Exhibit MWD-8: Analysis of Customer-Related Costs

Q. PLEASE INTRODUCE OCA EXPERT WITNESSES AND SUMMARIZE THE TOPICS OF THEIR RESPECTIVE TESTIMONIES IN THIS PROCEEDING.

A. In addition to my testimony, OCA is sponsoring the testimony of five additional expert witnesses in this proceeding including:

- **Ms. Jennifer L. Rogers (OCA Statement 2),** Principal and Vice President at Exeter Associates, Inc. Ms. Rogers presents OCA's recommended rate base, pro forma operating income under present rates, and overall revenue deficiency for UGI-G.
- **Mr. David J. Garrett (OCA Statement 3),** Managing Member at Resolve Utility Consulting PLLC. Mr. Garrett presents OCA's recommended proposed return on equity ("ROE"), capital structure, and overall rate of return ("ROR").
- **Mr. James S. Garren (OCA Statement 4),** Senior Manager at NewGen Strategies and Solutions LLC. Mr. Garren presents OCA's recommended depreciation expense.
- **Ms. Barbara R. Alexander (OCA Statement 5),** Owner and Manager of Barbara Alexander Consulting LLC. Ms. Alexander addresses UGI-G's compliance with certain settlement conditions included in its recent 2025 rate case settlement, as well as UGI-G customer service quality and operational performance metrics.
- **Mr. Roger Colton (OCA Statement 6),** Owner of Fisher Sheehan & Colton, Public Finance and General Economics, Belmont, Massachusetts. Mr. Colton addresses the affordability of UGI-G rates, and UGI-G's compliance with agreements as part of its recent 2025 rate case settlement pertaining to low-income support programs.
- **Mr. Zach Teti (OCA Statement 7),** Senior Regulatory Analyst at OCA. Mr. Teti presents OCA's summary of public input from the Public Hearings in this proceeding.

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION BASED ON CURRENT MACROECONOMIC CONDITIONS?

A. I recommend the Commission take into consideration current macroeconomic conditions, including consumer affordability concerns, when determining just and reasonable rates for the

Company. Average Pennsylvanians are still struggling with lingering inflation concerns besides looking at potential additional concerns placed on them due to fallout from the conflict in the Persian Gulf. This while the Company has seen increasing stock prices for its shareholders and no obvious market distress. The Commission, in particular, should require some level of shared burden, balancing consumer affordability concerns with the financial interests of the Company. I have been advised by counsel that the OCA will argue in their legal briefs that the Commission should not grant UGI any increase in this proceeding due to the substantial affordability concerns that consumers are facing.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING REGULATORY LAG?

A. The Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. Rather, the evidence, including statements made by its parent company, suggests that regulatory lag is already being effectively managed. The Commission should reaffirm the value of regulatory lag as a structural feature of traditional ratemaking and recognize that further erosion of this principle is neither necessary nor justified in this case.

Q. WHAT IS YOUR POSITION ON THE CONTINUATION OF THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENT?

A. I recommend that the Commission affirmatively discontinue the current Weather Normalization Adjustment ("WNA") mechanism. The mechanism has failed to produce balanced outcomes for ratepayers, functioning as an asymmetric surcharge on customers' bills for the three full years the mechanism has been in operation, even though the mechanism was designed to symmetrically provide both surcharges and credits to customers. The WNA is also not required to

address regulatory lag concerns of the Company given the Company's use of a Fully Projected Future Test Year ("FPFTY") and Distribution System Investment Charge ("DSIC").

Q. DO YOU HAVE ANY ALTERNATIVE PROPOSAL IF THE COMMISSION DECIDES TO CONTINUE THE WNA?

A. I recommend that the Commission increase the deadband from three percent to five percent and eliminate the month of October from the WNA period if the Commission determines that the WNA should continue. This would strengthen ratepayer protections and would furthermore make the Company's WNA pilot consistent with the recent WNA pilot the Commission approved for Columbia Gas. WNA communications with customers should also be reformed to include a historical presentation of incremental charges and credits as recommended by Ms. Alexander.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED ALLOCATED COST OF SERVICE STUDY?

A. I recommend that the Commission adopt an alternative cost of service approach that better aligns with cost causation principles and the way the Company's distribution system is designed and operated. Specifically, I recommend the use of a Peak and Average ("P&A") cost allocation methodology using weights based on the Company's test year system load factor in place of the Company's Average and Excess ("A&E") approach for allocating distribution system costs. Conceptually, my proposed P&A cost allocation method is similar to the earlier Seaboard method relied on to allocate costs associated with distribution mains. However, where the Seaboard method uses a 50-50 weighting of the demand and volumetric components, my proposal would base these weights on the Company's system load factor, or the ratio of peak day system requirements to average daily system requirements. This bases the weights of the two components

in a P&A cost allocation method on empirical data specific to the Company's Pennsylvania operations. The Company's test year system load factor is 42.36 percent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE APPORTIONMENT?

A. I recommend the Commission adopt a more reasonable revenue apportionment method based on my alternative Allocated Cost of Service Study ("ACOSS") results that also limits the rate increase compared to the Company's proposed revenue allocation method. Specifically, I recommend that the Commission cap the rate increase to any single customer class to no more than 1.15 times the system average increase and also remove all proposed rate decreases in the current proceeding. My proposal would increase base rates for the residential class by 14.01 percent under the Company's proposed revenue requirement increase, compared to the Company's proposed increase to these same customers of 15.05 percent.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in residential and commercial customer charges. The Company's proposed increase in customer charges comes in the immediate aftermath of an 8.3 percent increase in these same charges in the Company's prior rate case, Docket No. 2024-3052716. Furthermore, an analysis of customer-related costs finds that residential rate classes are currently recovering a significant portion of customer-related costs through monthly customer charges. The proposal would also negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the Company's current customer charges for all customers.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I recommend that the Commission limit its increase in the Company's monthly customer charges to the percentage rate increase class revenue requirement. In the context of my proposed revenue apportionment this would be a 14.01 percent increase for residential customers at the Company's proposed overall requested rate increase. This would correspond to a roughly $2.25 increase in the monthly residential customer charge, or an increase from the current $16.25 per month to $18.50 per month. I further recommend that any increase in customer charges be subject to scalebacks to reflect changes in allocated class revenue increases pursuant to Commission Orders.

III. CURRENT MACROECONOMIC SITUATION

Q. WHAT IS YOUR UNDERSTANDING OF THE PURPOSE OF THIS PROCEEDING?

A. The purpose of this case is to determine the "just and reasonable" rates for the Company under Chapter 13, and other provisions, of the Public Utility Code.

Q. WHAT ARE PUBLIC UTILITIES IN THE CONTEXT OF REGULATION?

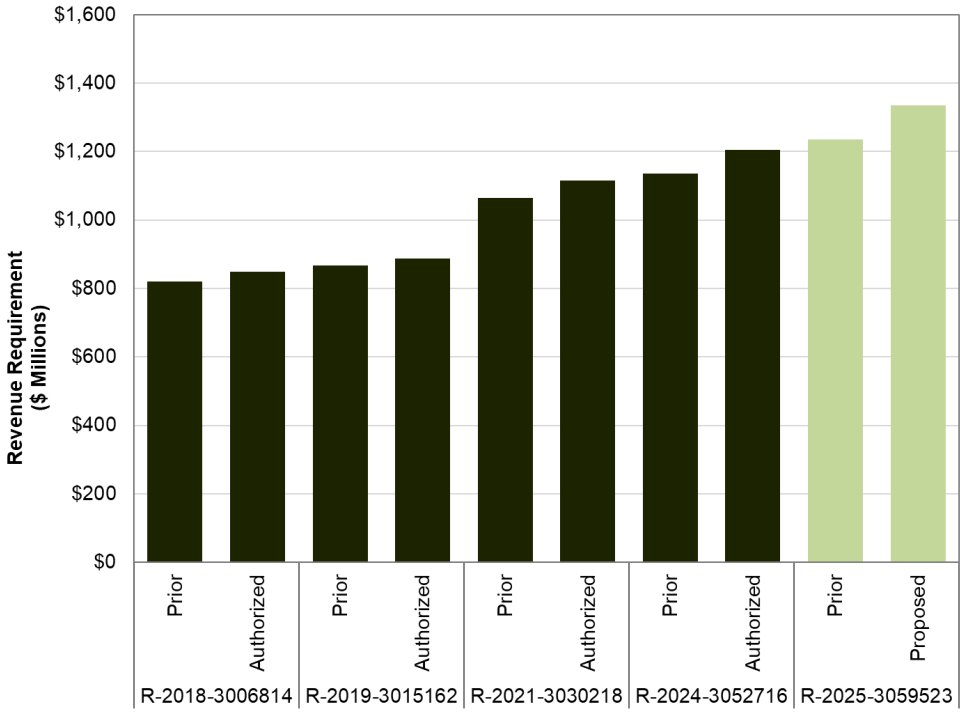
A. Public utilities are considered in economics to be natural monopolies, specifically that the high capital cost associated with the establishment and operations of public utilities renders having multiple competing services – as would be found in other industries – economically inefficient and therefore not in the public interest. Regulation, therefore, is designed as a substitute for the disciplining forces that would be found in competitive markets that prevent an industry from using its unfettered monopolistic powers to set prices and conditions of service. However, regulators

cannot tip the scale so far in the favor of consumers that regulation becomes confiscatory to the public utility by preventing the utility from the opportunity to earn a reasonable rate of return on their investment and deprives the utility of sources of capital.

Q. AS A NON-LAWYER, HOW IS THE PHRASE "JUST AND REASONABLE" GENERALLY VIEWED IN THE CONTEXT OF REGULATION?

A. Regulators typically evaluate "just and reasonable" in the context of what is called a "zone of reasonableness." This inherently assumes that there is no one correct answer to the question of "just and reasonable," but instead requires regulators to balance the interests of several sectors of the public, including not only utility investors, but also the interests of the utility's customers (that itself is comprised of different classes of customers with different individual interests) and the public policy interests of local governments impacted by the utility's operations. Importantly, this framework of regulation implies that regulators must be cognizant of the larger macroeconomic situation impacting utility customers, and how this impacts customers' ability to afford utility service.

Figure 1: Historic UGI-Gas Revenue Requirement Increases



Source: Final Orders and Compliance Filings.

Q. HOW DOES THE CURRENT PROCEEDING COMPARE WITH THE COMPANY'S PREVIOUS RATE CASE?

A. In the current filing, the Company requests a $99.4 million, or approximately 8.0 percent, increase in its currently authorized revenues. This is immediately on the heels of the Company's prior rate case (Docket No. R-2024-3052716) decided by the Commission in October of 2025, where the Company was authorized to increase revenues by $69.5 million. Figure 1 above shows the Company's proposed rate increase in conjunction with its last four rate increases since 2019, and demonstrates the burden these continual rate increases have placed on Company ratepayers. Since 2019, ratepayers have seen rates increase by more than 45 percent in just six years, averaging nearly 7.6 percent per year. If the current requested rate increase is approved, the cumulative increase since 2019 will exceed 57 percent, averaging nearly 9.5 percent per year.

Q. IS THERE ANY EVIDENCE THAT UGI CUSTOMERS ARE FACING AFFORDABILITY PRESSURES?

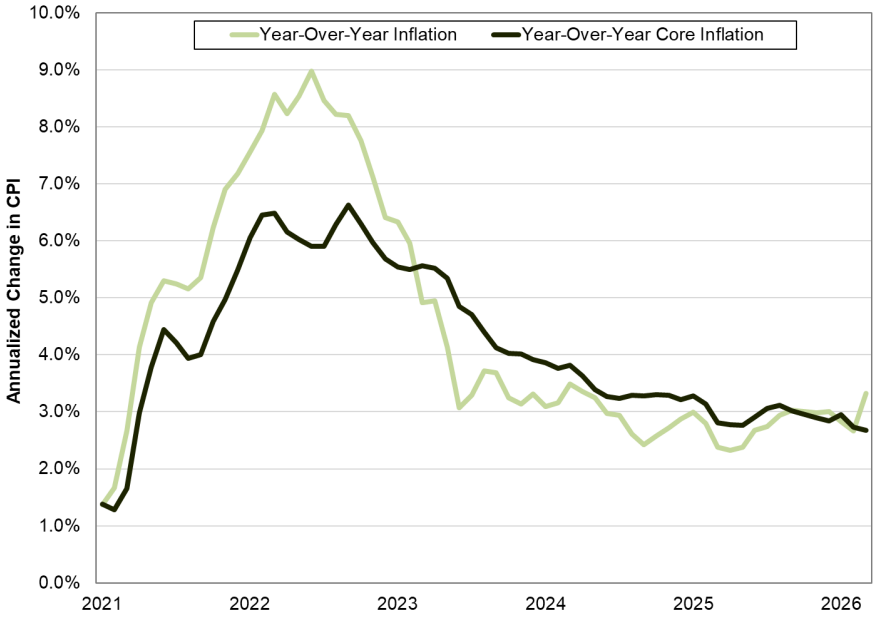
A. Yes. Both customer terminations and reconnections have been increasing in recent years. Specifically, customer terminations have increased by 36 percent from the years 2021 to 2025, with reconnections similarly increasing by 31 percent during the same period.[1] This indicates that customers are struggling to maintain natural gas service in the context of the Company's recent authorized rate increases and other macroeconomic pressures these customers are facing. These rate increases are contributing to broader affordability concerns placed on consumers.

Q. WHAT DO YOU MEAN BY AFFORDABILITY CONCERNS?

A. By affordability concerns, I mean the increasing burden on residential customers when utility costs are added to already elevated household expenses. Utility rate increases do not occur in a vacuum. Consumers experience utility rate increases alongside the ongoing price increases of food, housing, transportation, and other necessities. These concerns are especially acute for low-income households who devote a larger portion of their income to these necessities. It is for this reason that it is important to consider whether broader consumer prices remain elevated when establishing rate increases.

[1] Pennsylvania Public Utility Commission, *Utility Consumer Activities Report and Evaluation (UCARE) 2023* (January 2025). Pennsylvania Public Utility Commission, *2024 Residential Collections Data* (June 2025); Pennsylvania Public Utility Commission, *Terminations and Reconnections: Year-to-Date December 2024 vs. Year-to-Date December 2025* (January 16, 2026).

Figure 2: Monthly Growth in CPI

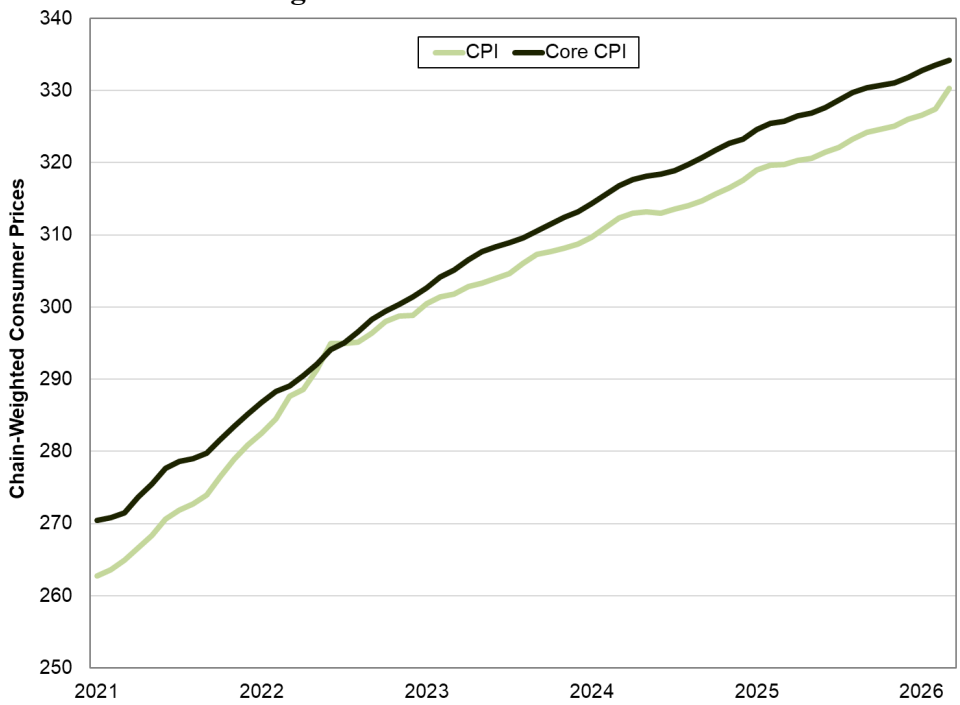


Source: Bureau of Labor Statistics

Q. IS THERE ANY EVIDENCE OF RISING PRICES IN CONSUMER PRODUCTS?

A. Yes. One commonly used measure of changes in the prices of goods and services is the Consumer Price Index ("CPI"), which is published by the U.S. Bureau of Labor Statistics ("BLS"). CPI measures changes over time in the prices consumers pay for a representative basket of goods and services, including food, energy, transportation, shelter, and other commodities. While the annualized growth in CPI has fallen from devastating highs that were seen in the immediate aftermath of the 2020 pandemic, it should be recognized that CPI is still elevated, reaching 3.3 percent in March 2026. This is well above the Federal Reserve's annual inflation target of 2.0 percent.

Figure 3: Consumer Price Index



Source: Bureau of Labor Statistics

Q. DOES THE MODERATING OF CPI GROWTH RATE FROM ITS HIGHS IMMEDIATELY FOLLOWING THE 2020 PANDEMIC MEAN THAT CONSUMER PRICES HAVE FALLEN?

A. No. It is important to recognize that CPI is reported monthly in terms of an annualized increase in consumer prices, meaning that a decline in the monthly 'headline' CPI does not mean that consumer prices have decreased, but rather that the rate of growth in consumer prices has slowed. Figure 3 shows that overall consumer prices have been continually increasing since at least 2021, even while the rate of growth has somewhat stabilized. Over the period January 2021 to January 2026, overall consumer prices increased 24.3 percent, while "core" consumer prices – which remove volatile energy and food prices – increased nearly 23.1 percent.

Q. HAS THE FEDERAL RESERVE MADE ANY STATEMENTS REGARDING RECENT INFLATION?

A. Yes. Chairman Powell addressed this in a recent press conference on March 18, 2026. The Federal Reserve's preferred measure of inflation is the Personal Consumption Expenditures Price Index ("PCE"), a related, but generally broader, measure of consumer inflation similar to CPI that is produced by the U.S. Bureau of Economic Analysis ("BEA"). Specifically, CPI is limited to out-of-pocket spending on goods and services by urban households while PCE extends this "basket of goods" to include rural households and third-party expenses on the consumer's behalf, such as employer-provided health insurance, Medicare and Medicaid.[2] He stated that estimates indicate that over the twelve months ending in February 2026, PCE and Core PCE prices rose by 2.8 percent and 3.0 percent, respectively.[3]

Q. HAS THE FEDERAL RESERVE RELEASED ANY INFLATION PROJECTIONS FOR 2026?

A. Yes. In the same press conference referenced above, Powell stated that the median PCE projection for 2026 is 2.7 percent.[4] Total PCE inflation of 2.7 percent would be 70 basis points above the Federal Reserve's 2.0 percent longer-run inflation goal. This is important because the Federal Reserve's own outlook has inflation above target levels in 2026. This means that consumers are expected to continue dealing with increasing pressures on their cost of living.

Q. ARE THERE ANY OTHER REPUTABLE INFLATION PROJECTIONS?

---

[2] "Inflation – Measuring the cost of living: The CPI versus the PCE price index," Cleveland Federal Reserve, Center for Inflation Research; note that changes in annual PCE inflation on average have been 0.39 percent than changes in annual CPI inflation.

[3] Board of Governors of the Federal Reserve System, Transcript of Chair Powell's Press Conference, Mar. 18, 2026, at 2.

[4] *Id*.

A. Yes. The Federal Reserve Bank of Philadelphia releases the Survey of Professional Forecasters, which includes inflation projections. In the First Quarter 2026 Survey, released on March 6, 2026, the forecasters project that CPI and core CPI will both rise 2.6 percent. [5] This is measured on a fourth-quarter-over-fourth-quarter basis. This suggests that professional forecasters also expect inflation to remain elevated enough to affect affordability.

Q. WHAT IS THE EFFECT OF THIS CONTINUOUS INFLATIONARY PROCESS?

A. This continuous inflationary process means that when prices rise at abnormally high levels, there must be compensatory periods of lower levels for inflation to return to its long-term average. For example, if the average annual inflation rate is two percent, then a year with three percent inflation would need to be followed by a year with approximately one percent inflation to return to the average trend. Even though present inflation is below the levels seen in 2022 and 2023, it is still above two percent, so there must be periods below this target to return to the long-term average. Until the economy experiences these off-setting low inflationary periods, consumers must bear the cumulative effects of the price level rising more quickly than its average trend.

Q. HAVE ENERGY-RELATED PRICES ALSO CONTRIBUTED TO AFFORDABILITY PRESSURE?

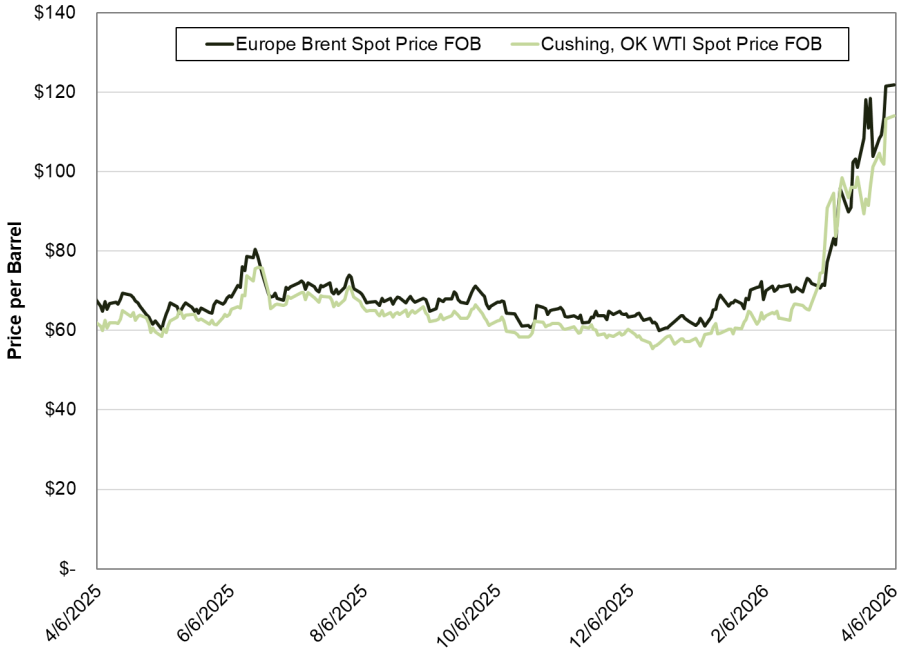
A. Yes. Pennsylvania consumers are currently experiencing financial pressure from all aspects of the energy market. Wholesale electricity prices in the PJM western hub, for example, increased 48.8 percent on average from 2024 to 2025. Likewise, Pennsylvania natural gas citygate prices increased 2.8 percent from December 2024 to December 2025 on the back of a nearly 41.9 percent increase in wholesale natural gas prices during the same period.

[5] Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter 2026, released Mar. 6, 2026, at 4.

Q. HAVE ANY RECENT DEVELOPMENTS INCREASED MARKET UNCERTAINTY?

A. Yes. Recent geopolitical and macroeconomic developments have increased uncertainty in energy markets and prices in a way that is relevant to consumer affordability. The most notable of these is the geopolitical conflict in the Persian Gulf affecting energy prices. Currently it is unknown what the lasting impact of this conflict will have on global markets, as this will be heavily influenced by how long the conflict continues. However, initial impacts on international and domestic markets present a word of caution.

Figure 4: Crude Oil Prices



Source: U.S. Energy Information Administration

Q. HOW HAS CONFLICT IN THE PERSIAN GULF AFFECTED MARKET UNCERTAINTY?

A. The conflict in the Persian Gulf has contributed to recent elevated crude oil prices in both international and domestic markets. International crude oil measured at the Brent hub in the North Sea has increased by more than 78.9 percent since the beginning of the recent conflict. Likewise,

domestic crude oil prices measured in terms of West Texas Intermediate ("WTI") have increased by nearly 70.3 percent since the beginning of the recent conflict. Both indexes are now trading in excess of $100 per barrel, well above the historic range of $60-$80 per barrel that is normally seen for these commodities.

Q. WHY ARE INCREASES IN CRUDE OIL PRICES IMPORTANT TO THE CONTEXT OF THE CURRENT RATE PROCEEDING?

A. The observed increase in crude oil prices shows how price shocks caused by the conflict in the Persian Gulf will likely filter through the larger macroeconomy. While the US does not purchase significant volumes of crude from the Persian Gulf anymore, the Persian Gulf is a major supplier of crude oil internationally, and crude oil is an international commodity. Therefore, domestic crude prices have already increased to reflect the knowledge that domestic supplies will be diverted in the international marketplace to take up the slack from constrained international supplies. Besides directly impacting Pennsylvanians through higher retail gasoline prices, higher crude prices will likely impact other aspects of the daily lives of Pennsylvanians already struggling under lingering inflation concerns. In fact, the Energy Information Administration reported that domestic gasoline prices recently have been more closely tied to Brent Oil prices than WTI.[6]

Q. COULD INCREASED OIL PRICES AFFECT AFFORDABILITY CONCERNS FOR UGI-G CUSTOMERS?

A. Yes. First the conflict in the Persian Gulf has restricted the flow of not only crude oil, but also Liquified Natural Gas ("LNG") supplies from the Persian Gulf to consumers in Asia. It is likely that these consumers will turn to alternative supplies from the US as stored supplies dwindle.

[6] U.S. Energy Information Administration, "U.S. gasoline prices move with Brent rather than WTI crude oil," Today in Energy, dated Nov. 3, 2014.

This will, in turn, place upward pressures on wholesale natural gas prices in the US as more natural gas is diverted to international supplies. Likewise, higher oil prices will lead to higher prices of downstream products as the increased transportation costs caused by higher gasoline and diesel prices are incorporated into retail prices. In the same Federal Reserve press conference discussed above, Chairman Powell stated that these elevated energy prices will push up overall inflation in the near term, but the scope and duration of these effects are uncertain.[7]

Q. IS THERE SIGNIFICANT UNCERTAINTY REGARDING HOW THE CURRENT CONFLICT WILL IMPACT THE ECONOMY?

A. Yes. As stated above, the ultimate impact of the recent conflict in the Persian Gulf is hard to predict because it is heavily determined by the ultimate length of the conflict, and how quickly international commodity markets can return to normal. Indeed, Chairman Powell, when asked if he believed the oil shock would be temporary, replied, "So, and the thing I really want to emphasize is that nobody knows. The economics effect could be bigger, they could be smaller, they could be much smaller or much bigger. We just don't know."[8]

Q. ARE THERE ANY OTHER RELEVANT INDICATORS OF MARKET UNCERTAINTY?

A. Yes. The VIX index represents a market of financial derivatives of S&P 500 traded on the CME Group, and is therefore a commonly used measure of expected near-term stock market volatility, as financial derivatives, such as options, become more valuable during periods of uncertainty. The VIX index has seen a 50 percent increase in value since the start of the recent

[7] Board of Governors of the Federal Reserve System, Transcript of Chair Powell's Press Conference, Mar. 18, 2026, at 2.

[8] *Id.* at 6.

conflict in the Persian Gulf, indicating elevated concern regarding future stock market volatility.[9] I have also reviewed the Federal Reserve Bank of Philadelphia's Survey of Professional Forecasters regarding growth and the likelihood of negative real GDP growth.

Q. WHAT DOES THE SURVEY OF PROFESSIONAL ECONOMISTS INDICATE?

A. The most recent survey presented a mixed picture. Forecasters increased their annual-average real GDP forecast for 2026 from 1.8 percent to 2.5 percent. However, they continued to assign a meaningful probability to a negative quarter of real GDP growth in 2026, with mean probabilities ranging from approximately 17.8 percent to 22.7 percent over the four quarters. [10] Assuming that each of these four probabilities is independent for illustrative purposes, this forecasts a 60.1 percent likelihood of a negative real GDP growth quarter in 2026. In my view, that does not establish that a recession is likely, but it does suggest that the outlook remains uncertain enough to support caution.

Q. HAVE TARIFFS ALSO AFFECTED AFFORDABILITY CONCERNS?

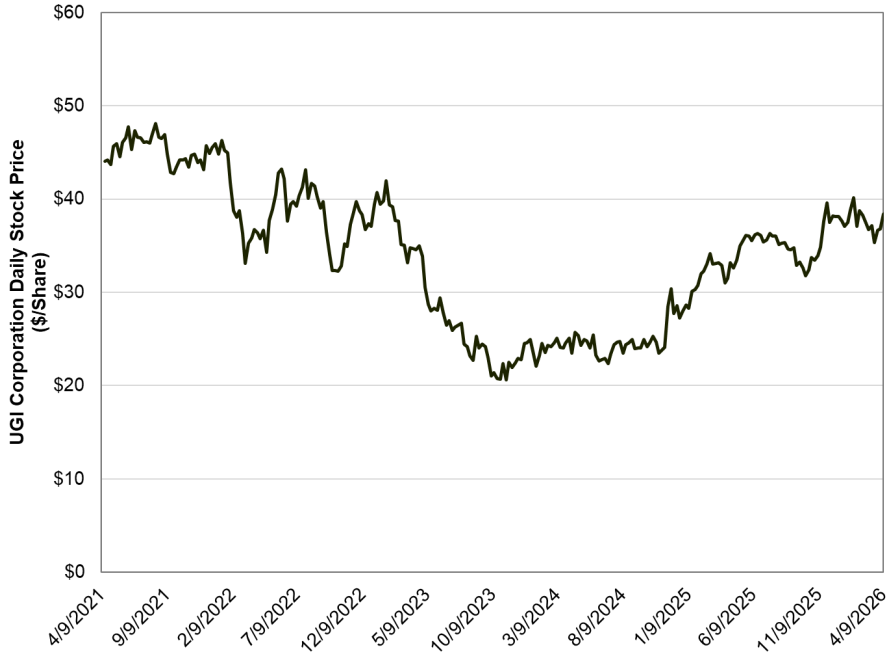
A. Although often lost in the current discussion regarding price concerns caused by the recent conflict in the Persian Gulf, it should be recognized that markets are also still dealing with uncertainty from recent tariffs placed on imports. Chairman Powell stated that of the Federal Reserve's 3.0 percent core inflation estimate, between .50 and .75 percentage points are due to

[9] Chicago Board Options Exchange via FRED, Data Set: CBOE Volatility Index: VIX, accessed April 2, 2026.

[10] Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter 2026, at 1, 6.

tariffs.[11] Federal Reserve materials indicate that those effects developed gradually rather than as a single price spike, and that some of the tariff increases were passed through to consumers.[12]

Figure 5: UGI Corporation Stock Price



Source: S&P Global

Q. HAS THE CURRENT FINANCIAL UNCERTAINTY CAUSED FINANCIAL STRUGGLES FOR THE COMPANY?

A. No, it does not appear that the Company has been experiencing significant financial concerns due to the recent macroeconomic concerns. On April 9, 2026, the common stock for UGI Corporation (the Company's ultimate parent) closed at $38.38 per share, a level consistent with where the company traded in late 2022 and early 2023, recovering its value from a minor decline

[11] Board of Governors of the Federal Reserve System, Transcript of Chair Powell's Press Conference, March 18, 2026, at 4.

[12] Board of Governors of the Federal Reserve System, The Slow Climb: How Tariffs Gradually Raised Retail Prices in 2025, FEDS Notes, March 5, 2026.

in value from late 2023 through 2024. This indicates that the Company is not in a position of obvious market distress.

Q. WHAT IS YOUR RECOMMENDATION BASED ON CURRENT MACROECONOMIC CONDITIONS?

A. I recommend the Commission take into consideration current macroeconomic conditions, including consumer affordability concerns, when determining just and reasonable rates for the Company. Average Pennsylvanians are still struggling with lingering inflation concerns besides looking at potential additional concerns placed on them due to the current conflict in the Persian Gulf. This while the Company has seen increasing stock prices for its shareholders and no obvious market distress. The Commission, in particular, should require some level of shared burden, balancing consumer affordability concerns with the financial interests of the Company.

IV. REGULATORY LAG

Q. PLEASE DISCUSS THE COMPANY'S REGULATORY LAG CONCERNS.

A. While the Company does not explicitly frame its concerns as "regulatory lag," its testimony reflects a clear focus on improving revenue stability and predictability within its existing rate structure.[13] The Company explains that variability in weather—particularly changes in heating degree days—can materially affect customer usage and, in turn, revenues. Specifically, warmer-than-normal conditions can lead to under-recovery of revenues, while colder-than-normal conditions can result in over-recovery. To address this issue, the Company proposes to extend its Weather Normalization Adjustment ("WNA") mechanism for an additional five years after the current expiration in October 2027.[14]

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[13] *See,* Direct Testimony of John D. Taylor, Company Statement No. 11 at 35:19 to 36:2.

[14] *Id.* at 32:6-8.

Q. DOES THE COMPANY ALREADY HAVE MECHANISMS IN PLACE THAT REDUCE REGULATORY LAG?

A. Yes. The Company utilizes a Fully Projected Future Test Year ("FPFTY") in this proceeding, which allows the Company to estimate future cost changes that will occur prior to the proposed implementation of new rates. The Company also already recovers a portion of its fixed costs through monthly customer charges, and in this proceeding, it proposes to increase those charges.[15] Lastly, the Company also has implemented a Distribution System Improvement Charge ("DSIC"), which allows for interim recovery of qualifying capital investments between rate cases. These tools provide the Company with multiple avenues to manage regulatory lag and ensure timely cost recovery. The proposed continuation of the WNA would further enhance this framework.

Q. DO CHANGES IN CUSTOMER USAGE NECESSARILY REFLECT REGULATORY LAG?

A. No. Declines in usage can result from a range of factors, including efficiency measures, economic conditions, or customer behavior. These changes are not inherently problematic and do not, by themselves, create regulatory lag. Moreover, if usage declines are accompanied by stable or declining costs, there may be no mismatch that requires correction.

Q. PLEASE DEFINE REGULATORY LAG.

A. Regulatory lag can be defined in several different ways. One definition holds that regulatory lag is the time period between when a utility's rates go into effect, after the course of

[15] *Id.* at 26.

an evidentiary hearing process and its next rate case.[16] Another definition holds that regulatory lag can be represented as the period between when a utility investment is undertaken and the time it enters into rates.[17] Yet another definition holds that regulatory lag is the time period in which a utility's achieved rate of return differs from that allowed by regulators.[18] At the heart of all these definitions is one theme: the frequency and timing of rate cases can impact utility earnings, positively or negatively.

Q. IN UTILITY RATE REGULATION, WHICH PARTY CONTROLS REGULATORY LAG OR THE DURATION OF TIME BETWEEN RATE CASES?

A. Typically, utilities control the duration between rate cases. In most states, utilities have the statutory ability to request rate increases if they believe that their rates are not affording them the opportunity to earn a fair return on and of their investments and prudently incurred costs. While state utility commissions and other stakeholders can, in theory, request a utility be "brought in" for a rate case, my experience is, and research indicates, that this event rarely happens. For instance, research on the topic of regulatory lag conducted in the early 1980s by Ronald Braeutigam and James Quirk, surveyed state utility rate cases during the period 1948 to 1978 and found that over 350 of the 363 surveyed rate cases (96 percent) were brought by a regulated utility, with the smaller number attributable to regulators or consumer groups. While this is an older, dated study, the results are likely to ring true even over the past two decades.

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[16] Scott E. Atkinson and Clifford Nowell. (1994). "Explaining Regulatory Commission Behavior in the Electric Utility Industry." *Southern Economic Journal*. Vol. 60, No. 3: 634-643.

[17] Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

[18] A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science* 4 (Spring): 82.

Q. DOES A UTILITY'S ABILITY TO DETERMINE THE TIMING OF A RATE CASE SHIFT A CERTAIN DEGREE OF REGULATORY RISK ONTO RATEPAYERS?

A. Yes. When the timing of a rate case is left in the hands of the utility, it can effectively shift the risk of regulation and regulatory lag away from itself and onto ratepayers. The option to request higher rates by utilities, in effect, creates a price floor that buttresses a utility's value.[19] This price floor allows shareholders to retain benefits created by regulatory lag (*i.e.*, earning an actual rate of return that is higher than the authorized rate of return, or over-earning), as well as the option to defend against challenges to those benefits through the timing of a rate case. Paul Joskow, writing as early as 1973, concluded in a frequently referenced regulatory article, that utility commissions tend to defend against rate increases, but are less aggressive in pursuing rate decreases when rates are stable or decreasing in real terms.[20] This outcome has often been thought to have occurred in the post-war period until about the late 1960s, and arguably throughout the 1990s.

Q. IS REGULATORY LAG UNFAIR OR CONFISCATORY TO UTILITIES?

A. No. The premise that regulatory lag is somehow unfair is simply antithetical to most of the research in utility regulation over the past 50 years. Regulatory lag has long been recognized as a key component of the overall regulatory compact, given the discipline it can impose on utility operational and investment decisions. Regulation acts as a substitute for the disciplines of competition.[21] Regulatory lag prevents utility regulation from devolving into a "cost-plus" approach that simply passes through costs on a dollar-for-dollar basis to ratepayers and can lead

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[19] Graeme Guthrie. (2006) "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

[20] Paul L. Joskow. (1973) "Pricing Decisions of Regulated Firms: A Behavioral Approach." *The Bell Journal of Economics and Management Science*. 4 (Spring):118-140.

[21] Charles F. Phillips, *The Regulation of Public Utilities: Theory and Practice*, (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 154.

to cost and investment inefficiencies. The cost-plus regulatory approach also shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes, which was recognized as early as the 1960s and has come to be known as the "Averch-Johnson" or "A-J" effect.

Q. HOW ARE THE CONCLUSIONS REGARDING REGULATORY LAG RELATED TO WHAT IS COMMONLY REFERRED TO AS THE "A-J EFFECT"?

A. In the early 1960s, a seminal article was published that dramatically influenced the theory and practice of utility regulation and economic thinking regarding the optimal regulation of natural monopolies. This article, authored by Professors Harvey Averch and Leland Johnson, and published in the *American Economic Review* in 1962, posited that rate of return regulation creates an incentive for regulated utilities to overcapitalize, resulting in an inefficient utilization of resources and higher-than-optimal rates.[22] This finding; however, was premised upon a model with a number of assumptions, one of which presumed there was no regulatory lag and that rates were set on a period-to-period basis. In other words, rates were set on a "cost-plus" regulatory approach.

Q. HOW IS REGULATORY LAG RELATED TO THIS RESEARCH?

A. Soon after its publication, Averch and Johnson's article was met with a flurry of scholarly research attempting to empirically verify the A-J effect, as well as examining the conditions under which the effect would and would not, be sustained.[23] Rejoinders to the research noted that two characteristics of the regulatory process tended to temper the likelihood and prevalence of the A-

[22] H. Averch and L. Johnson. (1962) "Behavior of the Firm under Regulatory Constraint," *American Economic Review*. 52:1052-1069.

[23] These works are surveyed in Graeme Guthrie. (2006). "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

J effect: (1) the possibility of disallowances through the prudence review process[24] and (2) the positive efficiency incentives created by regulatory lag.[25] In fact, a series of articles published soon afterwards noted that regulatory lag typically creates incentives for utilities to seek efficiency opportunities between rate cases since the gains (profits) from those investments inure to shareholders instead of ratepayers.[26]

Q. HOW DID THE FINDINGS IDENTIFYING THE BENEFITS OF REGULATORY LAG ARISE?

A. One of the earliest works on the impact of regulatory lag was published in 1971 by William Baumol and Alvin Klevorick.[27] Their work was the first of what was to become a series of articles showing that regulatory lag actually diminished incentives for overcapitalization, since the earnings gained by avoiding these inefficient actions passed directly to shareholders. Soon after, Klevorick, writing separately from Baumol, built upon this model by explaining how multi-year regulatory lags, coupled with demand and cost uncertainty, created strong incentives for efficiency

[24] A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science.* 4 (Spring): 82. P. Joskow. (1974). "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation." *Journal of Law and Economics*, Vol. 17: 291-327. R.J. Gilbert and D.M. Newbery.(1988). *Regulation Games*. Working Paper 8879, University of California Berkeley, June 16.T.P. Lyons. (1991.) "Regulation with 20-20 Hindsight: 'Heads I Win, Tails You Lose'?" *Rand Journal of Economics*. Vol. 22 (Winter): 581-595.

[25] Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

[26] W.K. Viscusi, J.M. Vernon, J.R. Harrington, Jr. (1997) *Economics of Regulation and Antitrust*, Second Edition. Cambridge: MA: MIT Press, 380. See also the works surveyed in Graeme Guthrie. (2006). "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

[27] William J. Baumol and Alvin K. Klevorick. (1970). "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion." *The Bell Journal of Economics and Management Science*. 1 (Autumn):162-190.

to maintain profitability.[28] One of his additional findings at the time, however, was that these incentives might also discourage regulated firms from investing in research and development.

Q. HOW IS THIS DISCUSSION RELEVANT TO THE COMPANY'S CURRENT FILING?

A. The Company's filing focuses on concerns related to revenue variability and stability. However, as discussed above, regulatory lag can serve a beneficial regulatory function and does not, by itself, indicate a structural problem. The Company's ability to file rate cases at will, utilize FPFTYs, and recover infrastructure costs through the DSIC already provide mechanisms to reduce lag. As such, the insinuation that regulatory lag is a barrier to fair return is inconsistent with both its regulatory tools and academic literature.

Q. DOES REGULATORY LAG, WHILE ENCOURAGING EFFICIENCY, DISCOURAGE INNOVATION?

A. No. Interestingly, this notion is a myth that arises in the practice of public utility regulation but is debunked by several academic articles. Elizabeth Bailey, who also served as an economic researcher at Bell Laboratories, addressed this issue originally raised by Klevorick during this active period of regulatory scholarship in the 1960s and 1970s. Bailey found that regulatory lag helped to facilitate, not reduce, the incentives for cost-reducing innovations.[29] Bailey's work built upon earlier work that she did with Roger Coleman in 1971 that further supported the conclusions

[28] A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science*. 4 (Spring): 82.

[29]Elizabeth E. Bailey. (1974). "Innovation and Regulation." *Journal of Public Economics*. 3: 285-295.

of Baumol and Klevorick, that regulatory lag induces profit-maximizing firms to adopt minimum-cost production alternatives.[30]

Q. ARE THERE ANY PARALLELS AMONG REGULATORY LAG, INNOVATION, RELIABILITY, AND SAFETY?

A. Yes. The Company links its increased capital investments for safety, reliability, and system modernization to concerns about revenue stability under its current rate design. However, it should be recognized that the key benefits of regulatory lag are the weakening of the natural incentive for a utility to over-capitalize and the strengthening of the natural incentive for a utility to minimize production costs in order to increase shareholder profits.

Q. PLEASE EXPLAIN THE TERM "REGULATORY COMPACT".

A. The regulatory compact, as it is generally referred to in a regulatory policy context, allows utilities the opportunity to earn a fair rate of return of and on their investments as well as their prudently incurred costs. In return, utilities are expected to provide safe, adequate, efficient, and reasonable service and facilities.

Q. HAVE ANY STUDIES LOOKED AT THE IMPACT OF REGULATORY LAG FROM A BROAD INDUSTRY-WIDE PERSPECTIVE DURING THESE PAST PERIODS?

A. Yes, there have been a few studies that have examined regulatory lag during the inflationary period of the 1970s. The conclusions are mixed. Seth Norton, for instance, conducted empirical research examining 45 utilities over a period from 1945 to 1974. The period spans both the high-growth, high-productivity, low-cost periods for the industry prior to 1970 and the

[30]Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

inflationary low-growth periods throughout the 1970s. According to Norton, there were no significant financial impediments or opportunities created by regulatory lag in any of these periods.[31]

Q. WILL THE COMPANY'S PROPOSALS SHIFT ANY RISKS AWAY FROM ITSELF AND ONTO RATEPAYERS?

A. Yes. The Company's proposals are designed to insulate the Company from fluctuations in usage and weather-related variability. By guaranteeing recovery of authorized revenues regardless of actual customer consumption, these mechanisms significantly reduce the Company's exposure to traditional business risks. As a result, the risk of revenue underperformance due to declining sales, conservation, economic conditions, or unseasonably warm weather is shifted entirely onto ratepayers. Importantly, the Company has not proposed any corresponding ratepayer protections such as earnings tests, revenue caps, or performance incentives. This asymmetric risk allocation leaves ratepayers exposed to upward rate adjustments without any assurance of offsetting benefits or improved utility performance.

Q. PLEASE EXPLAIN HOW REGULATORY RISK IS SHIFTED TO RATEPAYERS.

A. As I discussed above, utilities typically control the timing of rate case filings. Accordingly, utilities enjoy the ability to request higher rates, as well as the protection afforded by a price floor that allows shareholders to retain benefits (*i.e.*, over-earning) created by regulatory lag. Thus, in times of over-earning, risk is shifted to ratepayers because utilities are not likely to elect to file a rate case. In times where a utility is under-earning, risk also is shifted to ratepayers because the utility can file for a rate increase.

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[31] Seth W. Norton. (1987). "In Search of Regulatory Lag." *Quarterly Journal of Business and Economics*. Vol. 26 No. 4 (Autumn):3-16.

Q. DOES THE PRESENCE OF REGULATORY LAG CREATE ANY POLICY SUPPORT FOR THE COMPANY'S PROPOSALS?

A. No. The presence of regulatory lag in and of itself does not create policy justification for the Company's proposals. Regulatory lag can lead to both costs and benefits for a regulated utility. The Company's proposals are incorrectly premised upon a presumption that regulatory lag is bad and always will be bad. Regulatory lag creates opportunities for utilities to achieve gains as well as losses. The simple fact that regulatory lag creates "opportunities" and not guarantees, is one of the reasons why regulatory lag is considered efficiency enhancing. There is a long and rich history in the practice and theory of utility regulation supporting these efficiency-enhancing conclusions. Thus, there is no inherent nor *a priori* policy rationale supporting the Company's proposals. If anything, past thought and practice in utility regulation supports rejection of proposals of this nature on a policy basis.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING REGULATORY LAG?

A. The Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. Rather, the evidence, including statements made by its parent company, suggests that regulatory lag is already being effectively managed. The Commission should reaffirm the value of regulatory lag as a structural feature of traditional ratemaking and recognize that further erosion of this principle is neither necessary nor justified in this case.

V. WEATHER NORMALIZATION PROPOSAL

Q PLEASE DISCUSS THE COMPANY'S WNA.

A. The Company's WNA is a ratemaking mechanism that adjusts customer bills during the heating season (October through April) based on deviations from what the Company defines as "normal" weather.[32] Specifically, the mechanism applies a formula using the ratio of normal heating degree days ("NHDDs") to actual heating degree days ("AHDDs") and applies that ratio to the weather-sensitive portion of each customer's usage to generate either a credit or a surcharge on the customer's bill.[33] A three-percent deadband is used to prevent minor weather variations from triggering bill changes.[34] The WNA is limited to weather-related usage changes and applies to residential customers, excluding Customer Assistance Program ("CAP") customers, as well as small commercial customers.[35]

Q. WHY ARE WEATHER NORMALIZATION ADJUSTMENTS TYPICALLY USED BY GAS UTILITIES?

A. Weather normalization adjustments are generally used to reduce revenue volatility that results from fluctuations in weather which can lower customer gas usage and thus reduce a utility's recovery of fixed costs through volumetric rates. The intent is to provide more predictable revenues for the utility while smoothing customer bills. However, this goal must be balanced with customer protections to ensure the mechanism does not systematically overcharge customers or remove all utility risk.

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[32] *See,* Direct Testimony of John Taylor, Company Statement No. 11 at 35:13-16.

[33] *Id.* at 35:5-7.

[34] *Id.* at 35:8-11.

[35] *Id.* at 35:12.

Q. CAN UTILITIES SMOOTH CUSTOMER BILLS WITHOUT A WNA?

A. Yes. Utilities typically offer normalized billing, also referred to as budget billing, to customers interested in establishing fixed monthly bills for purposes of budgeting by averaging expected annual utility charges over twelve equal monthly payments. Normalized billing also assists the utility by providing greater certainty regarding its monthly revenue streams from customers.

Q. WHAT IS THE COMPANY PROPOSING IN THIS CASE WITH RESPECT TO THE WNA?

A. The Company is proposing to extend its current WNA pilot mechanism for an additional five years beyond its current expiration in October 2027.[36] The Company is also proposing to adopt a ten-year historical average of HDDs for WNA calculations in place of the current 15-year average.[37] However, the Company does not recommend applying the normalization period on a rolling basis unless the Commission also adopts the same approach for determining base-rate billing determinants.[38] Instead, the Company proposes that the ten-year normals be updated in future base rate proceedings.[39]

Q. WHY DOES THE COMPANY PROPOSE TO MODIFY THE CURRENT WNA NORMALIZATION PERIOD FROM 15 YEARS TO 10 YEARS?

A. The Company proposes to modify the current 15-year normalization period used for WNA purposes with a 10-year normalization period to align with the Company's similar proposed

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[36] *Id.* at 32:6-7.

[37] *Id.* at 24:18-22.

[38] *See,* Direct Testimony of John Taylor, Company Statement No. 11, Exhibit JDT-2 at 3.

[39] *See,* Direct Testimony of John Taylor, Company Statement No. 11 at 24:18-19.

movement in the current proceeding for normalizing base rate revenues.[40] The Company specifically argues that using different weather baselines for the setting of base rates and for WNA calculations could introduce misalignments in future WNA recoveries.[41]

Q. WHAT ARE THE PRACTICAL EFFECTS FOR RATEPAYERS ASSOCIATED WITH THE PROPOSED CHANGE IN WNA NORMALIZATION PERIODS?

A. Assuming that a 10-year historical average will better reflect future weather conditions,[42] the proposes change in the Company's weather normalization should reduce future volumetric differences between actual and normal usage due to weather conditions.[43] Theoretically, this should also reduce the volatility of future WNA surcharges and credits. The Commission accepted a similar proposed change to a 10-year normalization period recently for Columbia Gas of Pennsylvania ("Columbia Gas"), noting that normalization periods longer than 10 years appeared to result in a "historical bias" that diminished recent warming trends.[44]

Q. HAS THE COMMISSION ADOPTED A STATEMENT OF POLICY REGARDING ALTERNATIVE RATEMAKING MECHANISMS LIKE THE WNA?

A. Yes. In 52 Pa. Code § 69.3302(a) the Commission established 14 separate distribution rate considerations in determining just and reasonable alternative ratemaking distribution mechanisms and rate design. Exhibit MWD-1 presents these 14 considerations, along with the relevant effect of the WNA on each consideration. My review of the Commission's consideration criteria finds

[40] *Id.* at 33:14-19.

[41] *Id.* at 34:1-3.

[42] *Id.* at 34:8-10.

[43] *Id.* at 34:15-17.

[44] Pennsylvania Public Utility Commission, Docket No. R-2025-3053499, Opinion and Order at 302.

that the current WNA either does not impact the Commission's areas of concern or will potentially worsen those areas of concern.

Q. WHEN DID THE COMPANY FIRST IMPLEMENT ITS WNA MECHANISM?

A. The Company first implemented its WNA as part of its 2022 general rate case (Docket No. R-2021-3030218) when the Commission adopted a settlement approving the Company's proposed WNA as a five-year pilot program.[45] The settlement also required the Company to include a three percent deadband and to comply with certain reporting requirements.[46] It further provides that the continuation of the WNA pilot may be challenged or modified in future general rate proceedings.[47]

Q. HAS THE COMPANY'S WNA BEEN MODIFIED SINCE ITS INITIAL IMPLEMENTATION?

A. Yes. In the Company's most recent general rate case (Docket No. R-2024-3052716), the Commission approved a settlement that adopted several modifications to the WNA pilot.[48] The modifications include the following:[49]

- The Company was required to review and enhance its WNA customer communication materials, including sharing draft revisions with the parties, and the Universal Service Advisory Committee ("USAC") for feedback, with the review process to be completed by December 31, 2025.
- The WNA pilot was modified so that it no longer applies to May bills and instead applies only to bills rendered during the heating season months of October through April.

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[45] Pennsylvania Public Utility Commission, *Order.* Docket No. R-2021-3030218 at ¶ 2. Pennsylvania Public Utility Commission, *Recommended Decision.* Docket No. R-2021-3030218 at Section IV, ¶ 40.

[46] Pennsylvania Public Utility Commission, *Recommended Decision.* Docket No. R-2021-3030218 at Section V, ¶ 42(a)-(d).

[47] Pennsylvania Public Utility Commission, *Recommended Decision.* Docket No. R-2021-3030218 at Section V, ¶ 42(a).

[48] Pennsylvania Public Utility Commission, *Order.* Docket No. R-2024-3052716 ¶ 1. Pennsylvania Public Utility Commission, *Recommended Decision.* Docket No. R-2024-3052716 at Section V, ¶ 58.

[49] Pennsylvania Public Utility Commission, *Recommended Decision.* Docket No. R-2024-3052716 at Section V, ¶ 58(a)-(e).

- The WNA pilot was modified so that it no longer applies to confirmed low-income customers participating in the CAP who are billed on a percent-of-income basis, effective for bills rendered on and after November 1, 2025.
- The Company was required to provide additional reporting regarding the number and percentage of bills that receive upward adjustments due to warmer-than-normal weather and downward adjustments due to colder-than-normal weather.
- The settlement reaffirmed that the WNA pilot will end on October 31, 2027 unless affirmatively extended by Commission order, and provides that any request to continue or modify the WNA must be filed by the Company no later than January 31, 2026, and must include a report and recommendation evaluating the use of a rolling ten-year historical average to calculate NHDDs.

Q. WHAT IS THE EFFECT OF THE COMPANY'S PROPOSAL IN THIS PROCEEDING TO EXTEND THE WNA PILOT?

A. The Company's proposal would extend a relatively new pilot mechanism before it has been subject to meaningful evaluation. In its short operations, the WNA has consistently produced net surcharges for customers and operates without key safeguards such as reconciliation, earnings tests, or weather trend adjustments. By seeking to extend the WNA, the Company is effectively attempting to shield itself from weather-driven sales risk, while continuing to recover fixed costs through volumetric charges. This conversion would institutionalize an asymmetric mechanism that benefits the utility without demonstrating corresponding benefits to ratepayers.

Table 1: Summary of WNA Annual Reports

	Heating Season			
	2022-2023	2023-2024	2024-2025	2025-2026
OCT	$ -	$ 258,355	$ 795,006	$ 374,502
NOV	1,536,159	1,280,999	3,968,165	(1,384,160)
DEC	1,021,184	2,267,281	1,388,659	(6,571,747)
JAN	6,152,516	8,167,157	(1,431,770)	(5,580,525)
FEB	10,999,357	9,077,681	(1,513,534)	(14,440,359)
MAR	9,194,818	11,847,340	4,406,295	-
APR	4,311,784	4,906,085	5,750,700	-
MAY	487,940	2,918,063	2,950,691	-
Heating Season Total	**$33,703,758**	**$40,722,960**	**$16,314,211**	**$(27,602,289)**
Billing Cycle Adjustments (Jun - Sept)	$ (7,809)	$ 188,380	$ 13,069	-

Source: Company Responses to Data Request OCA-7-2 and OCA-8-50.

Q. WHAT HAS BEEN THE ACTUAL IMPACT OF THE WNA ON RATEPAYERS?

A. The actual impact of the WNA on residential and non-residential customers has resulted in net bill surcharges during each of the three full heating seasons under the mechanism to date. The Company has filed WNA reports with the Commission that summarize the monthly dollar amounts of WNA charges and credits issued to customers.[50] Table 1 includes a summary of the over/under collections reported by the Company since the inception of the mechanism in November 2022. During the first three heating seasons, 2022-2023 through 2024-2025, the Company collected approximately $90.7 million in net WNA revenues from customers. Each of those heating seasons produced a net surcharge to customers. Despite the Company claiming that the mechanism is symmetrical,[51] these results to date show that customers have experienced significant net surcharges during the majority of the pilot period.

Q. ARE ONE-WAY SURCHARGE MECHANISMS CONSISTENT WITH SOUND REGULATORY POLICY?

A. No. Regulatory policy disfavors mechanisms that allow utilities to recover lost revenues or costs from customers without also exposing the utility to comparable downside risk or performance standards. The WNA, as designed and applied by the Company, operates as a one-way ratchet: it imposes surcharges but has failed to provide meaningful refunds. This violates basic ratemaking principles of fairness and reciprocity between ratepayers and shareholders.

Q. ARE THERE OTHER CONCERNS REGARDING THE WNA?

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[50] Pennsylvania Public Utility Commission, *Weather Normalization Adjustment Pilot Reporting.* Docket No. R-2021-3030218 and R-2024-3052716.

[51] Response to Discovery Request OCA 8-62.

A. Yes. There are several concerns regarding the level of ratepayer protections included in the Company's WNA. Specifically, the WNA includes a three percent deadband and applies during an October through April heating season, both of which differ from protections that have been approved by the Commission in other Pennsylvania WNA mechanisms, including the Commission's recent decision modifying the WNA pilot mechanism for Columbia Gas in Docket No. R-2025-3053499. Exhibit MWD-2 provides a survey of recent Pennsylvania natural gas rate cases involving major investor-owned utilities that address WNA mechanisms and their related provisions.

Q. DO YOU AGREE WITH THE COMPANY'S THREE PERCENT DEADBAND?

A. No. As part of the settlement in the Company's 2022 general rate case, the Company included a three percent deadband in its WNA.[52] However, more recent Commission decision approving WNA pilot mechanisms have included a larger deadband, such as the five percent deadband approved in the recent Columbia Gas general rate proceeding.[53] Indeed, in that proceeding, the Commission explicitly held that a five percent deadband "adequately captures what could be considered normal weather fluctuations in Pennsylvania."[54] The Commission further explained that a larger deadband places more responsibility for calculating and forecasting weather variations on the utility as a normal part of doing business.[55] Consistent with this reasoning, increasing the Company's deadband from three percent to five percent would provide

[52] Pennsylvania Public Utility Commission, Recommended Decision. Docket No. R-2021-3030218 at Section V, ¶ 42(a).

[53] Pennsylvania Public Utility Commission, *Opinion and Order.* Docket No. R-2025-3053499 at 301.

[54] *Id*.

[55] *Id*.

greater protection to ratepayers and better align with the Commission's recent determination on this issue.

Q. DO YOU AGREE WITH THE COMPANY'S CURRENT WNA HEATING PERIOD OF OCTOBER THROUGH APRIL?

A. No. I disagree with the inclusion of the month of October in the Company's WNA heating season period. The Fall month of October is best represented as a shoulder month between the summer cooling season and the winter heating season which often sees little heating or cooling requirements for customers and customers only see heating use during years with early winters. The inclusion of this shoulder month within the Company's WNA heating season exposes ratepayers to unnecessary variation in the WNA by shifting the weather risk during this shoulder periods from the Company onto ratepayers.

Table 2: Analysis of Historic Weather Variability

	Standard Deviations			Coefficient
	-1	0	1	Variation
OCT	272	334	396	19%
NOV	580	679	778	15%
DEC	802	934	1,067	14%
JAN	974	1,123	1,271	13%
FEB	779	934	1,088	17%
MAR	615	770	926	20%
APR	355	436	516	18%
MAY	105	165	225	36%

Source: National Oceanic and Atmospheric Administration, National Centers for Environmental Information, GHCN-Daily.

Q. HAVE YOU EXAMINED HISTORIC WEATHER VARIABILITY IN THE COMPANY'S SERVICE AREA DURING THE PRIOR OCTOBER THROUGH MAY NORMALIZATION PERIOD?

A. Yes. Table 2 examines historical variation in monthly AHDD for the October through May period using a simple average of weather data from eight weather stations located in the Company's service territory over the 15-year period October 2010 through May 2025. This analysis finds that the coefficient of variation ("COV") for AHDD is greatest in the month of May, but also elevated during the fall month of October and some spring months.

Q. WHAT DO YOU MEAN BY THE COEFFICIENT OF VARIATION?

A. COV is mathematically the standard deviation of a data series divided by its mean and is a way to present the variance of different data series on a normalized basis as a percent of the average of the data series. For example, the COV of AHDD for the month of May is 36 percent, meaning that the average expected variance in AHDD during the month of May is 36 percent of the expected NHDD based on historic averages. Likewise, the COV of AHDD for the month of October is 19 percent of expected NHDD based on historic averages.

Q. WHAT IS YOUR POSITION ON THE CONTINUATION OF THE COMPANY'S WNA?

A. I recommend that the Commission affirmatively discontinue the current WNA mechanism. The mechanism has failed to produce balanced outcomes for ratepayers, functioning as an asymmetric surcharge on customers' bills for the three full years the mechanism has been in operation, even though the mechanism was designed to symmetrically provide both surcharges and credits to customers. The WNA is also not required to address regulatory lag concerns of the Company given the Company's use of a FPFTY and DSIC.

Q. DO YOU HAVE ANY ALTERNATIVE PROPOSAL IF THE COMMISSION DECIDES TO CONTINUE THE WNA?

A. I recommend that the Commission increase the deadband from three percent to five percent and eliminate the month of October from the WNA period if the Commission determines that the WNA should continue. This would strengthen ratepayer protections and would furthermore make the Company's WNA pilot consistent with the recent WNA pilot the Commission approved for Columbia Gas. WNA communications with customers should also be reformed to include a historical presentation of incremental charges and credits as recommended by Ms. Alexander.

VI. ALLOCATED COST OF SERVICE STUDY

A. Introduction

Q. WHAT IS THE PURPOSE OF AN ALLOCATED COST OF SERVICE STUDY?

A. An allocated cost of service study ("ACOSS") is a modeling approach that reconciles utility costs and revenues across different customer classes. The goal of an ACOSS is to evaluate the cost of providing service and revenue responsibility for each individual customer class. ACOSS results are used to estimate class-specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS AN ACOSS PREPARED?

A. An ACOSS utilizes a set of historic or projected cost information which is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e., production, transmission, and distribution). In the specific case of a natural gas utility, a large share of a utility's investments and costs are associated with providing distribution services. The classification process characterizes costs by "type," including those that are (1) demand-related, (2) commodity-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. PLEASE EXPLAIN DEMAND-RELATED COSTS?

A. Demand-related costs are associated with meeting maximum gas flow requirements. Transmission and large distribution mains are designed, in part, to meet peak demand day requirements such that natural gas can be delivered to households, businesses, and industries under peak load conditions. Gas supply contracts can also have a capacity component that is demand-related. The most common demand allocation factors used in an ACOSS are those related to system peak day demands.

Q. HOW ARE COMMODITY-RELATED COSTS DEFINED?

A. Commodity-related costs are defined as those that tend to change with the amount of throughput (volume) sold or transported. The investment cost of natural gas mains, for instance, can be allocated, in part, on some measure of throughput. There are also a number of other expenses, such as fuel costs themselves, that are often allocated using some measure of throughput.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

A. The allocation process is the final step in a cost of service study and involves assigning each functionalized and classified cost component to the appropriate customer classes. In the Company's ACOSS, costs are allocated using factors that reflect the underlying cost drivers, including customer counts, peak demand contributions, commodity usage, and, in some cases, revenues. Where costs can be directly attributed to a specific customer class, they are directly assigned. For costs that cannot be directly assigned, allocation factors are developed using

economic and engineering principles to ensure that costs are distributed in a manner consistent with cost causation. The goal of the allocation process is to ensure that each customer class is assigned its proportionate share of the Company's total costs, based on how that class contributes to the need for those costs.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting an ACOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in an ACOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES AN ACOSS RELATE TO ECONOMIC PRINCIPLES?

A. An ACOSS is also referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the ACOSS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. An ACOSS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic

theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS ACOSS METHODOLOGIES?

A. The ACOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While those activities are focused on determining the total level of revenues to be recovered, the ACOSS determines how those revenues are allocated across customer classes and ultimately recovered through rates. The primary controversies in evaluating different ACOSS methodologies for a natural gas utility generally center on which cost drivers should be emphasized in allocating distribution system costs. In particular, there is often disagreement regarding whether costs should be allocated based on customer counts, peak demand contributions, annual throughput, or some combination of these factors. For gas utilities, these issues are especially important because the system is designed to meet winter peak demand requirements, while a significant portion of costs are recovered through volumetric charges that vary with usage. As a result, different methodologies can produce materially different outcomes depending on how they treat peak demand versus throughput. For example, methodologies that rely more heavily on customer and peak demand factors tend to allocate a greater share of costs to lower load-factor customers, such as residential and small commercial classes, which place relatively high demands on the system during peak periods. Conversely, methodologies that incorporate throughput or average usage, such as Seaboard-type approaches,[56] tend to shift costs toward higher load-factor customers, such as larger commercial and industrial classes. These

[56] The Atlantic Seaboard, or Seaboard, cost allocation method allocates costs associated with distribution mains to customer classes based on a simple average of the customer classes' contribution to system peak day demands and annual throughput requirements.

differences can be significant, and they often drive the core disputes in a cost of service study. Ultimately, the key issue is whether the selected methodology appropriately reflects cost causation—that is, whether it aligns the allocation of costs with the way the natural gas distribution system is actually designed, constructed, and operated to serve customers.

Q. PLEASE EXPLAIN WHY METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS SHIFT COSTS TOWARD LOWER LOAD-FACTOR CUSTOMERS SUCH AS RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS.

A. A large portion of residential and small commercial natural gas usage is highly weather-sensitive, particularly during the winter heating season. These customers tend to have usage patterns that are concentrated during cold weather periods, when heating demand is highest. In contrast, larger commercial and industrial customers often use natural gas for process loads that are less dependent on weather and tend to be more consistent throughout the day and across seasons. As a result, their usage profiles are generally more stable and less "peaked" than those of residential and small commercial customers. Because of these differences, residential and small commercial customers typically exhibit lower load factors, meaning a greater share of their total usage occurs during peak periods. Larger customers, by comparison, tend to have higher load factors, with usage that is more evenly distributed over time. When a cost allocation methodology places significant weight on peak demand, it assigns more costs to those customer classes that contribute more heavily to system peak requirements. Since residential and small commercial customers drive a substantial portion of winter peak demand, methodologies that emphasize peak considerations will tend to allocate a greater share of costs to those classes. Conversely, methodologies that incorporate average usage or throughput, such as peak and average approaches,

tend to recognize the more consistent utilization of the system by higher load-factor customers and can result in a more balanced allocation of costs.

Q. PLEASE DEFINE WHAT IS MEANT BY A "LOAD FACTOR."

A. A load factor is defined as the ratio of the average gas usage over a given period to the maximum or peak demand experienced during that same period. It is typically expressed as a percentage. For natural gas, load factor can be calculated by dividing the total gas usage over a period (e.g., annual throughput) by the product of the peak day demand and the number of days in the period.

$$Annual\ Load\ Factor = \frac{Annual\ Throughput}{(Peak\ Day\ Demand * 365\ Days)}$$

A system or customer class with a high load factor is one that uses gas more consistently over time, with relatively smaller differences between average and peak usage. These customers tend to utilize the system more steadily. Conversely, a low load factor indicates that usage is more concentrated during peak periods—such as during cold weather—requiring the system to maintain sufficient capacity to meet those peaks, even if that capacity is not utilized for much of the year.

Q. IS IT PREFERABLE TO PROMOTE THE DEVELOPMENT OF HIGHER LOAD FACTORS?

A. Yes, generally speaking, a higher load factor can be indicative of more efficient utilization of the natural gas distribution system, all else equal. Customers with higher load factors tend to use the system more consistently over time, which can reduce the need for excess capacity that is only required during peak periods—particularly during the winter heating season when demand is highest. However, it is important to recognize that natural gas utilities inherently serve customers with different usage characteristics and load profiles. Residential and small commercial customers,

for example, tend to have more weather-sensitive usage patterns, while larger commercial and industrial customers often have more stable, process-driven loads. Additionally, gas utilities operate within a broader system that includes upstream supply, storage, and transportation arrangements, which can help manage variability in demand and mitigate some of the impacts of differing load characteristics across customer classes. While rate design should recognize and encourage efficient system utilization where appropriate, caution should be exercised in placing too much emphasis on promoting higher load factors. Overemphasizing this objective can result in shifting costs away from higher load-factor customers and onto lower load-factor customers, such as residential and small commercial classes, in a manner that may not fully reflect cost causation. Accordingly, while load factor is a relevant consideration, it should not be the primary driver of cost allocation or rate design decisions.

Q. WHAT IMPACT DOES COST ALLOCATION HAVE ON REVENUE RECOVERY?

A. Cost allocation can have a significant impact on revenue recovery because it directly affects the rates charged to different customer classes, and those rates, in turn, influence customer behavior. Higher-use customers, such as large commercial and industrial customers, are generally more price sensitive than residential and small commercial customers. This is due to the relative impact that rate increases can have on their overall operating costs and the margins of the goods or services they produce. In the natural gas context, these customers often have alternatives available, including fuel switching to other energy sources, modifying production processes, or in some cases reducing or relocating operations. As a result, they tend to be more responsive to changes in rates. By comparison, residential and small commercial customers typically have fewer practical alternatives and are therefore less able to adjust their usage in response to price changes,

particularly for essential uses such as space heating during the winter. Because of these differences in price elasticity, the way costs are allocated among customer classes can influence the stability and predictability of revenue recovery. Allocating a disproportionate share of costs to more price-sensitive customers may increase the risk of reduced usage or load migration, which can, in turn, impact the Company's ability to recover its authorized revenue requirement. Accordingly, while cost allocation should remain grounded in cost causation principles, it is also important to recognize how allocation decisions can affect customer behavior and, ultimately, revenue recovery.

Q. WHAT IS A POTENTIAL MANNER IN WHICH AN ACOSS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS?

A. Natural gas utilities, like electric utilities, are capital-intensive and require significant investment in infrastructure—such as distribution mains, services, and related facilities—to deliver service to customers. As a result, how those plant-related costs are allocated plays a critical role in determining the cost of service for each customer class. One potential source of bias arises when cost allocation methodologies over-emphasize certain cost drivers in a way that shifts costs away from higher load-factor, more price-sensitive customers and onto lower load-factor customers, such as residential and small commercial classes. For example, placing excessive weight on peak demand measures—particularly those that do not fully reflect system diversity—can result in allocating a disproportionate share of costs to customer classes that contribute heavily to winter peak demand. Additionally, over-reliance on minimum system or customer-related classifications for distribution plant can attribute a large share of infrastructure costs to the mere existence of customers, rather than to the demand they place on the system. This can result in cost shifts that disproportionately impact lower load-factor customers. In each of these cases, the underlying issue

is whether the selected methodology appropriately reflects cost causation. When it does not, the resulting cost allocation can create inequities among customer classes and biased outcomes against certain groups of customers.

B. Overview of the Company's ACOSS

Q. PLEASE DESCRIBE THE COMPANY'S ACOSS

A. The Company's ACOSS follows a three step process where costs are first functionalized, meaning they are grouped according to the function they serve, including gas supply, storage, transmission, distribution, and customer-related functions.[57] Second, those functionalized plant and expenses are classified into three primary factors driving associated costs, including customer-related costs, demand-related costs, and commodity-related costs.[58] Finally, these classified plant investment and expenses are directly assigned to individual customers or class of customers where possible, and where not possible are allocated based on allocation factors designed to reflect cost causation through principles of both economics and engineering.[59]

Q. HOW DOES THE COMPANY ALLOCATE MAJOR PLANT INVESTMENTS, SUCH AS DISTRIBUTION MAINS?

A. The Company classified its distribution mains as demand-related and allocated their costs in two steps. First, the Company allocated a portion of the costs associated with distribution mains directly to the Rate XD Firm customer class based on an analysis provided by the Company.

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[57] *See,* Direct Testimony of John D. Taylor, Company Statement No. 11 at 5:19-22.

[58] *Id.* at 6:6-12.

[59] *Id.* at 7:13-18.

Second, the Company allocated the remaining balance using the Average and Excess ("A&E") cost allocation method.[60]

Q. HAVE YOU PREPARED A SUMMARY OF THE RESULTS OF THE COMPANY'S ACOSS?

A. Yes. A summary of the results of the Company's ACOSS is presented in Exhibit MWD-3. The Company finds that it will earn a system average rate of return under current rates during the fully projected future test year ("FPFTY") of approximately 6.55 percent. The Company also finds that class-based rates of return vary significantly across customer classes. For example, the Residential (Rate R) class is expected to earn a rate of return ("ROR") of approximately 5.20 percent during the FPFTY under current rates, while the Extended Large Firm (Rate XD) class is expected to earn a ROR of approximately 17.02 percent during the FPFTY under current rates.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED ACOSS?

A. Yes. I disagree with the Company's allocation of distribution mains based on an A&E cost allocation methodology. The A&E cost allocation methodology appropriately recognizes that distribution mains supply both peak and non-peak service and thus perform both a demand and commodity function. However, the A&E cost allocation methodology places a disproportionate weight on customer load factor when compared against other demand and commodity cost allocation methodologies.

C. Allocation of Distribution Mains

Q. PLEASE DISCUSS HOW THE COMPANY CLASSIFIES AND ALLOCATES ITS DISTRIBUTION MAINS COSTS.

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[60] *Id.* at 12:18-21.

A. The Company allocates distribution mains costs in two steps. First, a portion of these costs is directly assigned to certain large customers (Rate XD) based on a detailed analysis of the specific facilities used to serve those customers.[61] Second, the remaining distribution mains costs are allocated among customer classes using the A&E cost allocation methodology.

Q. DID THE COMPANY CONSIDER OTHER POTENTIAL COST ALLOCATION METHODOLOGIES FOR ALLOCATING COSTS ASSOCIATED WITH ITS INVENTORY OF DISTRIBUTION MAINS?

A. Yes. The Company states that it also considered using a customer/demand classification for distribution mains and a Peak and Average ("P&A") cost allocation methodology that applies a fixed 50-50 weighting to the peak and average components.[62] The customer/demand classification approach was rejected by the Company without further evaluation as the Commission correctly has not traditionally recognized a customer component associated with natural gas mains.[63] The Company evaluated the potential for a P&A cost allocation methodology further, and presented a comparison of this allocator compared to its chosen A&E allocator in its testimony.[64]

Q. PLEASE EXPLAIN THE P&A COST ALLOCATION METHODOLOGY.

A. P&A is a composite demand and commodity allocation factor similar to the Average and Excess ("A&E") cost allocation approach.[65] The P&A cost allocation methodology is based upon

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[61] *Id.* at 12:18-21.

[62] *Id.* at 15:6-11.

[63] *Id.* at 15:7-9.

[64] *Id.* at 16, Table 1.

[65] Gas Distribution Rate Design Manual (June 1989), National Association of Regulatory Utility Commissioners, pp. 27-28.

a two-component weighted average. The first component represents each rate class's share of a utility's system peak day demand, and the second represents each rate class's share of a utility's total annual throughput.[66] The exact weights used in a P&A cost allocation approach vary, including a straight 50-50 weighting of demand and commodity components, often referred to as the "Seaboard" method.

Q. PLEASE EXPLAIN THE SEABOARD COST ALLOCATION METHOD.

A. The *Atlantic Seaboard* method, (or "*Seaboard"* method), stems from a 1952 Federal Power Commission ("FPC," the predecessor agency to the Federal Energy Regulatory Commission ("FERC")) ruling establishing appropriate cost allocations for the Atlantic Seaboard natural gas pipeline.[67] In its ruling, the FPC explicitly addressed the fact that natural gas pipeline facilities are built to supply both peak and non-peak service, and thus perform both a demand and commodity function, and expressed particular concern that an over-assignment of pipeline costs (particularly transmission plant costs) to the demand or capacity function would result in an under-allocation of costs to large volume industrial customers on interruptible rates.[68]

> A natural-gas transmission facility performs both a capacity and a volumetric function. In this sense it is a joint facility, which thus presents the problem, always difficult, of allocating joint costs.
>
> … A pipeline would not normally be built to supply peak service, that is to say, service on the peak days only… pipelines are built to supply service not only on the few peak days but on all days throughout the year… Both capacity and annual use are important considerations in the conception of the project ... Both capacity and volume, therefore, are what are known as cost factors or incidences in respect to the capital outlay for a pipeline project. It follows that

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[66] *Id*.

[67] Re Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43.

[68] *Id*.

> reasonably accurate results can be achieved only by allocating the fixed expenses flowing from the capital outlay to both operating functions, viz., capacity and volume.[69]

Q. HAVE YOU ESTIMATED THE RESULTS OF AN ALTERNATIVE ACOSS USING THE COMPANY'S ESTIMATED P&A ALLOCATION WITH SEABOARD WEIGHTINGS?

A. Yes, and I have summarized these results in Exhibit MWD-4. Exhibit MWD-4 shows that an alternative ACOSS using P&A allocation of distribution mains with Seaboard weightings results in somewhat different results when compared to the Company's proposed ACOSS. In particular, under this alternative the residential service class will earn a 5.47 percent ROR during the FPFTY under current rates, or approximately 0.84 on a relative rate of return ("RROR") basis. This is compared to the results of the Company's proposed ACOSS which finds that its residential service class will earn a 5.20 percent return on ratebase during the FPFTY under current rates using its proposed A&E cost allocation methodology.

Q. PLEASE DESCRIBE THE A&E COST ALLOCATION METHODOLOGY.

A. Conceptually, A&E cost allocation methods involve developing two components that are combined by the use of a weighted average.[70] The first component, referred to as the "average" component, represents each rate class's average hourly energy consumption throughout the test year, and is calculated by simply dividing annual energy consumption for each rate class by 365 days in the year. The second component, referred to as the "excess" component, represents each

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[69] Conkling R.L. (2011), "Energy Pricing: Economics and Principles," pp. 96-97, citing Re Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43.

[70] *See*, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC") at 49-51.

class's contribution to system peak demand in excess of the class's average daily consumption. These components are combined through the use of a weighted average based on overall system load factor. Specifically, the average component is weighted by the utility's overall system load factor, while the excess component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. IS A P&A METHODOLOGY CONCEPTUALLY SIMILAR TO AN A&E METHODOLOGY?

A. Yes. The P&A methodology is similar to the A&E methodology that can also be utilized for classifying distribution mains. Conceptually, both methods involve developing a volumetric and demand component that are then combined by use of a weighted average. In other words, both methodologies are intended to be hybrid energy and demand allocators.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN A P&A METHODOLOGY AND AN A&E METHODOLOGY.

A. Although the P&A and A&E methodologies are conceptually similar, in practice, an A&E methodology places greater weight on a rate class's demand contribution and less weight on a rate class's annual energy usage than does a P&A methodology. This occurs because an A&E methodology values a class's peak demand, the "excess" component, relative to its average demand, thereby exaggerating the effect of a class's load factor on the relative classification of energy and peak demand elements. From a cost allocation perspective, this approach can disproportionately shift costs toward classes with lower load factors and away from classes with higher load factors, depending on how the weighting is applied. As a result, the use of an "excess" demand measure, rather than full peak demand, does not eliminate concerns regarding cost

allocation bias and may instead introduce additional distortions in how costs are assigned among customer classes.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE A&E COST ALLOCATION METHODOLOGY PLACES A DISTORTED EMPHASIS ON CUSTOMER LOAD FACTOR?

A. Yes. Consider a customer class with a very high load factor, where its average usage is close to its peak usage. Under the A&E cost allocation methodology, the "excess" demand component for that class would be relatively small, since there is little difference between average usage and peak demand. As a result, the methodology would assign a smaller share of demand-related costs to that class.

Q. WHY DO PROPONENTS OF THE A&E METHODOLOGY CLAIM THAT IT BETTER REFLECTS COST CAUSATION?

A. Proponents of the A&E cost allocation approach, typically large/industrial customer groups, argue that using full class peak demand "double counts" class energy use during periods. These stakeholders often argue that the use of "excess demand" rather than total demand solves this purported "double counting problem." However, in using the excess component only, the A&E methodology directly places a higher emphasis on each class's demand contribution relative to energy. Thus, the A&E method, itself, suffers from a bias that favors relatively higher load factor classes like industrial customers and at lower load factor classes' expense (such as residential and small commercial customers).

Q. DO YOU AGREE WITH CLAIMS ABOUT THE SUPERIORITY OF THE A&E METHODOLOGY?

A. No, such arguments incorrectly conflate the concepts of energy and demand and the roles each of these play in utility system planning. These arguments are also faulty since they effectively presume that utilities design systems to first meet the needs of non-weather dependent customers and only later expand system resources for customers with additional winter heating requirements. In reality demand and energy reflect separate and differing utility planning parameters and system planners develop its system to meet all of their throughput requirements, not separately to meet individual, or class-specific requirement.

D. ACOSS Recommendations

Q. PLEASE SUMMARIZE YOUR ACOSS RECOMMENDATIONS.

A. I recommend that the Commission adopt an alternative cost of service approach that better aligns with cost causation principles and the way the Company's distribution system is designed and operated. Specifically, I recommend the use of a P&A cost allocation methodology using weights based on the Company's test year system load factor in place of the Company's Average and Excess A&E approach for allocating distribution system costs. Conceptually, my proposed P&A cost allocation method is similar to the earlier Seaboard method relied on to allocate costs associated with distribution mains. However, where the Seaboard method uses a 50-50 weighting of the demand and volumetric components, my proposal would base these weights on the Company's system load factor, or the ratio of peak day system requirements to average daily system requirements. This bases the weights of the two components in a P&A cost allocation method on empirical data specific to the Company's Pennsylvania operations. The Company's test year system load factor is 42.36 percent.

Q. HAVE YOU PREPARED AN ALTERNATIVE ACOSS INCORPORATING YOUR PROPOSED CHANGES TO THE COMPANY'S ACOSS?

A. Yes. Exhibit MWD-5 presents the results of my alternative ACOSS which utilizes a P&A approach to allocate distribution-related costs in place of the Company's A&E methodology. This alternative study shows that the Company will earn a 5.36 percent ROR, or 0.82 on a RROR basis, from its residential customer class during the FPFTY using current rates. This compared to the results of the Company's proposed ACOSS which finds that its residential service class will earn a 5.20 percent ROR from its residential customer class during the FPFTY under current rates.

VII. REVENUE APPORTIONMENT

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE APPORTIONMENT PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which, in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the ACOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their ACOSS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be viewed as the initial step taken in establishing rates.

Q. DOES THE REVENUE APPORTIONMENT PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for certain under-earning

classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a set of broad ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally accepted ratemaking principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all the principles I mentioned above. However, any principle's relative weight can change depending on the importance of certain policy goals. Rate design should strike a balance between policy goals and principles that result in rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

Q. WHAT ARE THE COMPANY'S RATE DESIGN GOALS?

A. The Company states that it attempts to balance various criteria that relate to the design of utility rates.[71] The Company notes that economic, historical, and social factors all enter into its

[71] *See,* Direct Testimony of John D. Taylor, Company Statement No. 11at 19:9-12.

revenue apportionment process, and that, out of necessity, the rate design process must be partially influenced by judgmental evaluations.[72]

Q. HAVE YOU EXAMINED THE COMPANY'S PROPOSED REVENUE ALLOCATION?

A. Yes. Exhibit MWD-6 summarizes the Company's proposed revenue allocation. The Company constructed a three step process based on the results of its ACOSS to define a mitigated revenue allocation. First, the Company reflected slight rate decreases for competitively negotiated Extended Firm ("Rate XD Firm") and Interruptible Service ("IS") customers resulting from roll-in of the current Distribution System Improvement Charge ("DSIC") into base rates.[73] Second, Non-Residential General Service ("Rate N") customers were assigned a rate increase needed to move these customers to parity, equivalent to 1.18 times the system average increase.[74] Finally, the remaining Delivery Service ("Rate DS") and Large Firm ("Rate LFD") were assigned increases to remove approximately two-thirds of these classes' over-earnings going forward.[75] Remaining required revenues were fully assigned to the residential customer class.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED REVENUE APPORTIONMENT?

A. No. The Company's proposed revenue allocations suffer from two major deficiencies. First, the Company's proposal is based on the results of a faulty ACOSS that overstates the current rate of return the Company derives from its large commercial and industrial service customers

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[72] *Id.* at 19:12-15.

[73] *Id.* at 20:10-15.

[74] *Id.* at 20:15-16.

[75] *Id.* at 20:16-18.

while understating the rate of return the Company derives from its residential service customers. Second, the Company's proposed revenue apportionment process results in a rate increase that is inconsistent with rate gradualism.

Q. WHY DO YOU SAY THAT THE COMPANY'S PROPOSED REVENUE APPORTIONMENT IS INCONSISTENT WITH RATE GRADUALISM?

A. The Company's proposed revenue apportionment process results in inconsistent rate increases between the Company's customer classes. For example, under the Company's proposed revenue apportionment, Rate XD and IS customers will receive a small rate decrease, while the residential customer class will receive a 15.05 percent rate increase, equal to 1.24 times the proposed system average increase. Indeed, under the Company's proposal residential and non-residential general service customers would receive more than 98.7 percent of the Company's $99.4 million rate increase.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE APPORTIONMENT.

A. I recommend the Commission adopt a more reasonable revenue apportionment method based on my alternative ACOSS results that also limit the rate increase compared to the Company's proposed revenue allocation method. Specifically, I recommend that the Commission cap the rate increase to any single customer class to no more than 1.15 times the system average increase and also remove all proposed rate decreases in the current proceeding.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE APPORTIONMENT?

A. Yes. Exhibit MWD-7 presents an illustrative summary of the effects of my proposed revenue apportionment under the Company's proposed system average rate increase of 12.18

percent. My proposed revenue apportionment would increase base rates for the residential class by 14.01 percent, compared to the Company's proposal which would increase such rates by 15.05 percent, and would increase base rates for the non-residential general service customers by 13.49 percent, compared to the Company's proposed increase to these customers of 14.39 percent.

VIII. RATE DESIGN

Q. HOW ARE NATURAL GAS RATES TYPICALLY DESIGNED?

A. Natural gas utility rates are typically comprised of three elements. The first component is the fixed monthly customer charge, or what is sometimes referred to as the basic service charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of therms or dekatherms (Dth). Finally, demand rates are surcharges that are assessed based upon a customer's maximum usage during a billing period. Some smaller use customer classes, such as residential and small general services classes, are not demand-metered and thus, only face customer and volumetric charges in what is commonly called a "two-part tariff." Larger, demand metered, customers face a "three-part tariff" which includes a customer, volumetric, and demand charge. A "multi-part tariff" is a term often used to generalize a set of rates that have various combinations of both fixed (customer charge) and variable charges (energy and/or demand charges).

Q. HOW SHOULD POLICY BALANCE COST ASSIGNMENTS BETWEEN FIXED CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by the two-part and three-part tariff form that is sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most

appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES FOR A MULTI-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed costs" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a multipart tariff typically has more to do with consumer demand than it does with cost in a natural gas context given the capital-intensive nature of public utilities.

Q. DOES THE RATE DESIGN PROCESS HAVE ANY GOALS?

A. Yes. The development of utility rates, or "rate design" often has a few goals. For example, rates are sometimes designed to send certain price signals to consumers in order to influence their usage decisions.[76] Sometimes, rate design becomes a balancing act since rates must be designed to be both supply-eliciting (i.e., assist utilities in financing of capital investments) and demand-inhibiting (i.e., inhibit the growth in demand that generates the need for capital investments).[77]

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[76] Bonbright, James *et. al., Principles of Public Utility Rates,* Pub. Utils. R., Inc., Second Edition, at 96–97.

[77] *Id.*

Table 3: Summary of Company's Proposed Customer Charges

Rate Class	Current	Proposed	Increase
	------ $/month -----		
General Service			
Residential	$ 16.25	$ 23.00	41.5%
Non-Residential	$ 36.42	$ 39.00	7.1%
Commercial and Industrial Service			
Delivery Service	$300.00	$ 353.00	17.7%
Large Firm Delivery Service	$670.00	$ 670.00	0.0%

Source: Application, Books X and XI.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S BASIC SERVICE CHARGE PROPOSAL.

A. The Company proposes to increase the monthly customer charge for both its residential and non-residential general service rates, as well as its standard commercial and industrial delivery service rate. Most significant of these changes is the Company's proposed increase to its residential monthly customer charge, which the Company proposes to increase from $16.25 per month to $23.00 per month, a 41.5 percent increase.[78]

Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE INCREASE?

A. The Company claims its ACOSS supports a customer-related unit cost of $54.03 per month.[79] The Company therefore states that its proposed customer charge of $23.00 per month moves the customer charge towards the customer related unit cost, and therefore helps align the customer charge with the Company's fixed cost of service requirements.[80]

[78] *See,* Direct Testimony of John D. Taylor, Company Statement No. 11at 23:8-9.

[79] *Id.* at 26, Table 6.

[80] *Id.* at 27:10-16.

Q. HAVE YOU PREPARED AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH BASIC SERVICE CHARGES?

A. Yes. Exhibit MWD-8 presents an analysis of current basic service charges with the Company's customer-related expenses. "Customer-related" expense accounts for natural gas utilities are those typically allocated on the basis of customers and can include: removing and setting meters; maintenance of meters; meter reading expenses; customer records and collections; customer billing and account; and customer service and information expenses. These costs can also include the depreciation expense associated with service and meter plant accounts, as well as the carrying charges (at the Company's requested rate of return) on these plant accounts.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF COMPANY CUSTOMER-RELATED COSTS?

A. My analysis finds that the Company's current customer charge of $16.25 per month recovers 42.0 percent of the estimated customer-related costs of $38.66 per month. Likewise, I find that the current non-residential general service customer charge of $36.42 per month recovers 56.2 percent of the estimated customer-related costs of $64.76 per month.

Table 4: Recent Estimates of Customer-Related Residential Costs

Utility	Docket No.	Filing Year	Monthly Customer-related Costs
National Fuel Gas Distribution Corporation	R-2022-3035730	2022	$ 26.17
Peoples Natural Gas Company	R-2023-3044549	2023	$ 22.15
PECO Energy Company	R-2024-3046932	2024	$ 33.00
Pike County Light & Power Company	R-2024-3052357	2024	$ 53.76
Columbia Gas of Pennsylvania, Inc.	R-2025-3053499	2025	$ 29.43
UGI Utilities, Inc.	R-2024-3052716	2025	$ 51.19

Q. HOW DO THE COMPANY'S CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF YOUR ANALYSIS?

A. The Company's analysis includes costs that are not directly related to providing service to customers. However, more importantly, the Commission should recognize that the Company's customer-related expenses far exceed the customer-related expenses that have been provided by other natural gas companies operating in Pennsylvania. For example, in its recently filed rate case, National Fuel Gas Distribution Corporation estimated customer-related costs associated with serving residential customers of $26.17 per month, approximately half of the Company's estimated costs in this rate case.

Q. DO YOUR RESULTS INDICATE ANY PRESSING NEED TO INCREASE MONTHLY CUSTOMER CHARGE RATES?

A. No. The Company's residential and non-residential general service rate classes currently cover approximately half of their estimated monthly customer-related costs. This while the Company's customer-related expenses far exceed similar expenses that have been provided by other natural gas companies operating in Pennsylvania.

Table 5: Survey of Regional Customer Charges

Company	State	Residential Customer Charge ($/month)	Commercial Customer Charge ($/month)
UGI Utilities, Inc. (Current)	**PA**	**$ 16.25**	**$ 36.42**
UGI Utilities, Inc. (Proposed)	**PA**	**$ 23.00**	**$ 39.00**
Delmarva Power and Light Company	DE	17.00	69.20
Washington Gas Light Company	DC	19.05	34.40
Baltimore Gas and Electric Company	MD	16.15	39.05
Washington Gas Light Company	MD	11.85	21.50
Elizabethtown Gas Company	NJ	11.50	41.05
New Jersey Natural Gas Company	NJ	12.00	55.00
Public Service Electric and Gas Company	NJ	9.38	27.62
South Jersey Gas Company	NJ	10.50	40.50
KeySpan Gas East Corporation	NY	27.50	50.00
National Fuel Gas Distribution Corporation	NY	21.00	22.50
Niagara Mohawk Power Corporation	NY	23.75	28.60
Orange and Rockland Utilities, Inc.	NY	22.50	35.00
The Brooklyn Union Gas Company	NY	24.50	50.00
Columbia Gas of Pennsylvania, Inc.	PA	20.15	36.55
National Fuel Gas Distribution	PA	14.00	27.00
Peco Energy Company	PA	15.70	36.38
Peoples Natural Gas Company	PA	16.80	22.00
Peer Group Average		**$ 17.25**	**$ 37.43**

Source: Utility Tariffs

Q. HAVE YOU COMPARED THE COMPANY'S CURRENT AND PROPOSED RESIDENTIAL CUSTOMER CHARGE WITH OTHER REGIONAL PEER UTILITIES?

A. Yes. The Company's proposed residential customer charge of $23.00 would be well above the regional average of $17.25 per month charged by other investor-owned natural gas utilities. Indeed, the Company's proposed residential customer charge of $23.00 per month would be higher than that charged by any other Pennsylvania investor-owned natural gas utility. It is important to note that the average residential customer charge for investor-owned natural gas utilities operating in Pennsylvania is $16.66 per month, similar to the Company's current residential customer charge of $16.25 per month.

Q. ARE HIGHER BASIC SERVICE CHARGES CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's proposal is inconsistent with the promotion of energy efficiency and conservation in Pennsylvania for the simple reason that it places more costs into the fixed component of rates than in the variable component. This reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT INCREASED FIXED CHARGES HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission (MPSC) recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[81]

Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?

A. Yes. The Montana Public Service Commission ("MT PSC") addressed this issue in evaluating, and rejecting, a proposal by Energy West Montana to eliminate volumetric charges and

[81] Maryland Public Service Commission Case No. 9299*, In re of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates*, Order No. 85374 at 99 (Md. Pub. Serv. Comm'n, Feb. 22, 2013).

only have one fixed monthly customer charge (known as a "straight-fixed variable" or "SFV" rate design):

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
> …
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[82]

Q. HAVE ANY REGULATORY RESEARCH INSTITUTES ADDRESSED THE ISSUE OF THE RELATIONSHIP BETWEEN HIGH CUSTOMER CHARGES AND ENERGY EFFICIENCY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners (NARUC) lists Straight-Fixed Variable (SFV) rate design as an alternative to delink utility revenue from sales. An SFV attaches all fixed-related costs to fixed charges while relegating only variable charges to volumetric rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a

[82] In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas, Montana Public Service Commission, Docket No. D2010.9.90, Order No, 7132c, at 29–30, rel. November 17, 2011.

> fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[83]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH HIGHER CUSTOMER CHARGES?

A. Yes. The National Action Plan for Energy Efficiency (NAPEE), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[84]

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[83] NACUA, *Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)* (Sept. 2007), Grants & Research Department, Nat'l Assoc of Reg Util Comm'rs, at 5. (Emphasis added), available at https://www.maine.gov/mpuc/legislative/archive/2006legislation/DecouplingRpt-AttachC.pdf.

[84] National Action Plan for Energy Efficiency, *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design* at 13–14, prepared by William Prindle, ICF International, Inc. (Sept.2009) (emphasis added), available at https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.

Q. SHOULD THE COMMISSION BE MINDFUL OF THE EFFECT OF THE COMPANY'S PROPOSED RATE DESIGN ON LOW-USE RESIDENTIAL CUSTOMERS?

A. Yes. As discussed in more detail in the Direct Testimony of OCA Witness Roger Colton, higher customer charges disproportionately impact lower use residential customers which tend to be lower income customers.[85]

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in residential and commercial customer charges. The Company's proposed increase in customer charges comes in the immediate aftermath of an 8.3 percent increase in these same charges in the Company's prior rate case, Docket No. 2025-3059523. Furthermore, an analysis of customer-related costs finds that residential rate classes are currently recovering a significant portion of customer-related costs through monthly customer charges. The proposal would also negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the Company's current customer charges for all customers.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

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[85] *See,* Direct Testimony of Roger Colton, OCA Statement No. 6 at p. 10-11.

A. Yes. I recommend that the Commission limit its increase in the Company's monthly customer charges to the percentage rate increase class revenue requirement. In the context of my proposed revenue apportionment this would be a 14.01 percent increase for residential customers at the Company's proposed overall requested rate increase. This would correspond to a roughly $2.25 increase in the monthly residential customer charge, or an increase from the current $16.25 per month to $18.50 per month. I further recommend that any increase in customer charges be subject to scalebacks to reflect changes in allocated class revenue increases pursuant to Commission Orders.

IX. CONCLUSION AND RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION BASED ON CURRENT MACROECONOMIC CONDITIONS?

A. I recommend the Commission take into consideration current macroeconomic conditions, including consumer affordability concerns, when determining just and reasonable rates for the Company. Average Pennsylvanians are still struggling with lingering inflation concerns besides looking at potential additional concerns placed on them due to fallout from the conflict in the Persian Gulf. This while the Company has seen increasing stock prices for its shareholders and no obvious market distress. The Commission, in particular, should require some level of shared burden, balancing consumer affordability concerns with the financial interests of the Company. I have been advised by counsel that the OCA will argue in their legal briefs that the Commission should not grant UGI any increase in this proceeding due to the substantial affordability concerns that consumers are facing.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING REGULATORY LAG?

A. The Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. Rather, the evidence, including statements made by its parent company, suggests that regulatory lag is already being effectively managed. The Commission should reaffirm the value of regulatory lag as a structural feature of traditional ratemaking and recognize that further erosion of this principle is neither necessary nor justified in this case.

Q. WHAT IS YOUR POSITION ON THE CONTINUATION OF THE COMPANY'S WNA?

A. I recommend that the Commission affirmatively discontinue the current WNA mechanism. The mechanism has failed to produce balanced outcomes for ratepayers, functioning as an asymmetric surcharge on customers' bills for the three full years the mechanism has been in operation, even though the mechanism was designed to symmetrically provide both surcharges and credits to customers. The WNA is also not required to address regulatory lag concerns of the Company given the Company's use of a FPFTY and DSIC.

Q. DO YOU HAVE ANY ALTERNATIVE PROPOSAL IF THE COMMISSION DECIDES TO CONTINUE THE WNA?

A. I recommend that the Commission increase the deadband from three percent to five percent and eliminate the month of October from the WNA period if the Commission determines that the WNA should continue. This would strengthen ratepayer protections and would furthermore make the Company's WNA pilot consistent with the recent WNA pilot the Commission approved for Columbia Gas. WNA communications with customers should also be reformed to include a historical presentation of incremental charges and credits as recommended by Ms. Alexander.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED ALLOCATED COST OF SERVICE STUDY?

A. I recommend that the Commission adopt an alternative cost of service approach that better aligns with cost causation principles and the way the Company's distribution system is designed and operated. Specifically, I recommend the use of a P&A cost allocation methodology using weights based on the Company's test year system load factor in place of the Company's A&E approach for allocating distribution system costs. Conceptually, my proposed P&A cost allocation method is similar to the earlier Seaboard method relied on to allocate costs associated with distribution mains. However, where the Seaboard method uses a 50-50 weighting of the demand and volumetric components, my proposal would base these weights on the Company's system load factor, or the ratio of peak day system requirements to average daily system requirements. This bases the weights of the two components in a P&A cost allocation method on empirical data specific to the Company's Pennsylvania operations. The Company's test year system load factor is 42.36 percent.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED REVENUE APPORTIONMENT.

A. I recommend that the Commission adopt a more reasonable revenue apportionment method based on my alternative ACOSS results that also limits the rate increase compared to the Company's proposed revenue allocation method. Specifically, I recommend that the Commission cap the rate increase to any single customer class to no more than 1.15 times the system average increase and also remove all proposed rate decreases in the current proceeding. My proposal would increase base rates for the residential class by 14.01 percent under the Company's proposed

revenue requirement increase, compared to the Company's proposed increase to these same customers of 14.39 percent.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in residential and commercial customer charges. The Company's proposed increase in customer charges comes in the immediate aftermath of an 8.3 percent increase in these same charges in the Company's prior rate case, Docket No. 2024-3052716. Furthermore, an analysis of customer-related costs finds that residential rate classes are currently recovering a significant portion of customer-related costs through monthly customer charges. The proposal would also negatively impact the public policy goals of energy efficiency and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the Company's current customer charges for all customers.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN MONTHLY CUSTOMER CHARGES IS WARRANTED?

A. Yes. I recommend that the Commission limit its increase in the Company's monthly customer charges to the percentage rate increase class revenue requirement. In the context of my proposed revenue apportionment this would be a 14.01 percent increase for residential customers at the Company's proposed overall requested rate increase. This would correspond to a roughly $2.25 increase in the monthly residential customer charge, or an increase from the current $16.25 per month to $18.50 per month. I further recommend that any increase in customer charges be

subject to scalebacks to reflect changes in allocated class revenue increases pursuant to Commission Orders.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

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Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

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PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Distribution" (2025). Prepared for the Louisiana State University, Center for Energy Studies, Energy Fundamentals 2025. June 24 and July 8, 2025.

2. "Development Trends, Issues, and Challenges with Clean Hydrogen Production" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.

3. "Status and Future of Natural Gas Supply and Infrastructure" (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

4. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 2025-325-E (2026). Before the Public Service Commission of South Carolina. *In the Matter of the Application of Dominion Energy South Carolina, Inc. for Authority to Adjust and Increase its Retail Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

2. Expert Testimony. Docket No. 2025.09.072 (2026). Before the Public Service Commission of the State of Montana. *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* Of Behalf of the Montana Consumer Counsel. Issues: Cost Trackers, Cost of Service, Rate Design.

3. Expert Testimony. Case Nos. 25-0594-WW-AIR and 25-0595-WW-ATA (2026). Before the Public Utilities Commission of Ohio. *In the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service.* On Behalf of the Staff of the Public Utilities Commission of Ohio Rates and Analysis Department, Regulatory Service Division. Issues: Cost of Service, Rate Design.

4. Expert Testimony. Case No. 25-0593-ST-AIR (2026). Before the Public Utilities Commission of Ohio. *In the Matter of the Application of Aqua Ohio Wastewater, Inc. to Increase Rates for Sewer Service.* On Behalf of the Staff of the Public Utilities Commission of Ohio Rates and Analysis Department, Regulatory Service Division. Issues: Cost of Service, Rate Design.

5. Expert Testimony. Docket No. UG-250610 (2026). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Northwest Natural Gas Company.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: Cost of Service, Rate Design.

6. Expert Testimony. D.P.U. 25-85 (2025). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 for Approval of a General Increase in Base Distribution Rates*

for Gas Service and a Performance-Based Ratemaking Plan. On Behalf of the Massachusetts Office of the Attorney General. Issues: Cost Benchmarking.

7. Expert Testimony. Docket No. 2025-172-E (2025). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

8. Expert Testimony. Docket No. 2025-154-E (2025). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: Cost of Service, Rate Design, Alternative Regulation.

9. Expert Testimony. Cause No. 46258. (2025). Before the Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for Authority to Increase Rates and Charges for Electric Utility Service Through a Phase-In Rate Adjustment; and For Approval of Related Relief, Including (1) Revised Depreciation Rates, Including Cost of Removal Less Salvage and Updated Depreciation Expense; (2) Accounting Relief, Including Deferrals and Amortizations, (3) Inclusion of Capital Investment, (4) Rate Adjustment Mechanism Proposal, Including a New Propoerty Tax Rider, and (5) New Schedules of Rates, Rules and Regulations for Service.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

10. Expert Testimony. Docket Nos. R-2025-3055010, R-2025-3055011, and R-2025-3055012. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. The Pittsburgh Water and Sewer Authority d/b/a Pittsburgh Water.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Alternative Regulation, Regulatory Lag.

11. Expert Testimony. Docket No. G-04204A-24-0237. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Gas, Inc. Devoted to its Operations Throughout the State of Arizona and for Related Approvals.* On Behalf of the Staff of the Arizona Corporation Commission. Issues: Cost of Service, Rate Design.

12. Expert Testimony. Docket No. R-2025-3054394. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

13. Expert Testimony. Docket No. R-2025-3054393. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Valley Energy, Inc.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

14. Expert Testimony. Docket No. R-2025-3054392. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Wellsboro Electric Company.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Cost of Service, Rate Design.

15. Expert Testimony. Docket No. R-2025-3053499. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

16. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

17. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD.* On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.

18. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.

19. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, In. for a Hearing to Determine the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return.* On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.

20. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery

21. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

22. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.

23. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.

24. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.

25. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.

26. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.

27. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

28. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

29. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

30. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

31. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

32. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

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Commission Alternative Regulation Consideration (§ 69.3302)

	Commission Consideration Criteria	UGI Claim	Response
§ 69.3302(a)(1)	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	UGI Gas's WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. The Company recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.	The WNA does not address the Commission's consideration criteria aligning revenues with cost causation. The WNA is premised on ensuring the Company will recover its annual fixed costs of providing gas distribution service; however, the WNA adjustment is applied as a variable charge to customer's bills.
§ 69.3302(a)(2)	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company's gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company's ability to make prudent investments necessary to maintain safe and reliable service.	Proposed WNA does not impact capacity utilization, as the determining metric for the charge is weather, not utilization.
§ 69.3302(a)(3)	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer's anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 10-year average rather than a 15-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions. Please refer to UGI Gas Exhibit JDT-2.	The WNA adjustment mechanism creates the anomaly where customers see rate increases when they reduce consumption and rate decreases when they increase consumption. If the WNA is generating revenue, then it inherently does not reflect the level of demand associated with the customer's anticipated consumption levels, because the WNA only generates revenue if the demand is less than anticipated.
§ 69.3302(a)(4)	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	UGI Gas's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.	The WNA may have led to intraclass cost shifting to the extent that smaller use residential customers typically have a greater percentage of natural gas use that is temperature-sensitive compared to larger use residential customers.
§ 69.3302(a)(5)	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.	The WNA does not limit or eliminate disincentives for the promotion of energy efficiency. The WNA is solely tied to adjustment in customer usage attributed to changes in heating requirements and is not impacted by a reduction in customer use due to energy efficiency initiatives. The Company has not demonstrated that the lack of a WNA would present a major obstacle for the promotion of energy efficiency programs.
§ 69.3302(a)(6)	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.	The WNA may be perceived as a disincentive to employ energy efficiency measures for customers whose energy efficiency initiative takes place during periods of warmer than normal weather. These customers will see increased WNA charges after reducing usage through implementing energy efficiency initiatives.
§ 69.3302(a)(7)	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.	In accordance with the Settlement Agreement in Docket Nos. R-2024-3052716, et al., the current WNA mechanism does not apply to low-income customers enrolled in the Company's Customer Assistance Program ("CAP").	The WNA may harm low-income customers as these customers have less ability to weatherize homes to reduce impact of weather fluctuations on consumption.
§ 69.3302(a)(8)	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.	The WNA adds another surcharge to customers' bills without any showing that the WNA would reduce the frequency of base rate case filings. It therefore does not improve rate stability.

Commission Alternative Regulation Consideration (§ 69.3302)

	Commission Consideration Criteria	UGI Claim	Response
§ 69.3302(a)(9)	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months of October through April, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.	While the WNA is premised on reducing risks to the Company revenue stability caused by fluctuations in weather conditions, in practice it is not a revenue neutral mechanism. None of the three full heating seasons the WNA has been in effect for (2022-2023, 2023-2024, and 2024-2025) have produced net credits for ratepayers. Indeed, over these 3 heating seasons the Company has collected on net more than $90.7 million from ratepayers through the WNA.
§ 69.3302(a)(10)	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	The WNA does not impact the Company's rate case frequency nor it effects regulatory lag.	Historically the Company has filed multiple rate case over the last decade, despite possessing the WNA. This is unlikely to change and the WNA does not prevent the Company from seeking additional rate increases driven by future investment needs or higher expenses and associated cost recovery. The WNA does, however, weaken the positive impacts regulatory lag has on promoting cost containment between rate cases. Regulatory lag has long been recognized as a key component of the overall regulatory compact that disciplines utility operational and investment decisions between rate cases. Regulatory lag in particular diminishes incentives for utilities to overcapitalize since the inefficiencies associated with overcapitalization are passed directly to shareholders until reviewed by the Commission in the utility's next rate case.
§ 69.3302(a)(11)	If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).	The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through April. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.	The WNA applies only to base rates and does not impact surcharges.
§ 69.3302(a)(12)	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	UGI Gas's WNA includes several consumer protections to ensure fairness and transparency, as follows: a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and outside of the deadband the WNA results in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. b. No Cross-Subsidization: The WNA is customer-specific. c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts. d. Customer Transparency and Education: UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.	The WNA does not include sufficient consumer protections. These include checks on over-earnings to prevent overall rate increases through WNA reconciliations.
§ 69.3302(a)(13)	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. As indicated above, UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.	Customers have no means of anticipating future WNA changes as it is impossible for customers to forecast WNA charges in advance and likely difficult for customers to calculate even after the fact. For these reasons elements of the WNA likely not understandable to customers and effectively is viewed as just another surcharge present on the customer's bill.
§ 69.3302(a)(14)	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudency and reasonableness would have been reviewed and deemed appropriate to support reliability driven initiatives. The proposed WNA would help minimize the volatility of the recovery of these costs.	The WNA has not lead to changes in the Company's quality of service, either positively or negatively. The WNA is not tied to achievement of increased service reliability performance, but has reduced the positive incentive of regulatory lag for the Company to control costs and led to customer confusion. The Company retains the ability to file rate cases using a projected future test year to address concerns associated with capital improvements required to facilitate reliable delivery of natural gas.

Survey of Approved Pennsylvania Natural Gas WNA Mechanisms

Witness: Deupree
Docket No. R-2025-3059523
Exhibit MWD-2

Utility	Docket No.	Filing Year	Decision Type	Customer Applicability	Pilot (Y/N)	Pilot Duration	Deadband	Heating Months	NHDD Methodology	Customer Education	Reporting Requirements	Other
National Fuel Gas Distribution Corporation	R-2022-3035730	2022	Settled	Residential, CAP, Commercial, and Public Authority	Y	5 years	3%	October-May	15-year average	Provide WNA and bill impact information.	Two annual WNA reports by month and customer class providing: (1) bills subject to WNA, (2) total bills, (3) volume adjustment, (4) revenue adjustment, (5) NHDDs and AHDDs.	N/A
Peoples Natural Gas Company	R-2023-3044549	2023	Partially settled	Residential, Commercial SGS, and Commercial MGS	N	N/A	3%	October-May	Based on HDDs adopted in R-2023-3044549 rate case	N/A	Annual report due September 1 providing: (1) monthly WNA billed revenues, (2) AHDD and NHDD data, (3) customer count and bill impacts by class.	(1) Separate line item on customer bills; (2) Bills rendered calculation basis; (3) May adjustment capped at 100% of billed distribution amount.
PECO Energy Company	R-2024-3046932	2024	Partially settled	---------- The Commission agreed with the ALJs' findings and denied PECO's request to implement a WNA ----------								
Pike County Light & Power Company	R-2024-3052357	2024	Partially settled	---------- The Company proposed a WNA mechanism but withdrew the proposal pursuant to settlement ----------								
Columbia Gas of Pennsylvania, Inc.	R-2025-3053499	2025	Litigated	RSS, RDS, and CAP	Y	Until final order in next base rate case	5%	November-April	10-year average	N/A	Annual report due October 1 providing: (1) monthly WNA computations and (2) all underlying supporting data.	N/A
UGI Utilities, Inc.	R-2024-3052716	2025	Settled	R, RT, N, and NT	Y	Until October 31, 2027	3%	October-April	15-year average	Review/revise WNA pilot communication materials with party input (review due 12/31/2025).	Two annual WNA reports by month and customer class providing: (1) bills subject to the WNA, (2) total bills, (3) volume and revenue adjustments, (4) NHDDs and AHDDs, (5) number and percentage of bills adjusted upward or downward due to warmer or colder than normal weather.	(1) CAP customers on percent-of-income bills exempt from WNA beginning November 1, 2025; (2) Future filing must evaluate use of rolling 10-year HDD average.

Summary of Results of Company's Proposed ACOSS: Relative Rate of Return at Current Rates (Dollars in Thousands)

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service (Rate IS)
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	
1	**Rate Base**							
2	Plant in Service	$ 6,676,559	$ 4,030,975	$ 1,590,903	$ 269,351	$ 453,637	$ 193,367	$ 138,327
3	Accumulated Reserve	(1,736,046)	(1,084,034)	(402,794)	(65,434)	(105,650)	(45,573)	(32,561)
4	Other Rate Base Items	(621,162)	(360,592)	(158,796)	(26,197)	(44,559)	(17,427)	(13,590)
5	**Total Gas Rate Base**	**$ 4,319,351**	**$ 2,586,349**	**$ 1,029,313**	**$ 177,720**	**$ 303,428**	**$ 130,366**	**$ 92,175**
6	**Operating Income**							
7	**Operating Revenues at Current Rates**							
8	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
9	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
10	Other Revenues	14,131	7,044	2,848	279	445	3,383	132
11	**Total Operating Revenues**	$ 1,234,682	$ 801,640	$ 271,880	$ 36,303	$ 59,236	$ 42,538	$ 23,085
12	**Operating Expenses**							
13	O&M and A&G Expenses	$ 715,943	$ 522,603	$ 152,903	$ 10,135	$ 14,582	$ 11,344	$ 4,377
14	Depreciation and Amortization Expense	170,518	111,318	36,287	5,953	9,500	4,547	2,912
15	Taxes Other than Income	15,249	9,392	3,369	670	979	522	317
16	Current Income Taxes	50,156	23,849	11,948	2,944	5,148	3,935	2,332
17	**Total Operating Expenses**	$ 951,866	$ 667,162	$ 204,507	$ 19,702	$ 30,209	$ 20,348	$ 9,938
18	**Total Operating Income**	**$ 282,817**	**$ 134,478**	**$ 67,373**	**$ 16,601**	**$ 29,027**	**$ 22,190**	**$ 13,147**
19	**Rate of Return on Rate Base ("ROR")**	**6.55%**	**5.20%**	**6.55%**	**9.34%**	**9.57%**	**17.02%**	**14.26%**
20	**Relative Rate of Return ("RROR")**	**1.00**	**0.79**	**1.00**	**1.43**	**1.46**	**2.60**	**2.18**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Results of Company's Proposed ACOSS: Required Increase at Equalized Rates (Dollars in Thousands)

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service (Rate IS)
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	
1	**Required Income Under Company's Proposed ROR**							
2	Total Gas Rate Base	$ 4,319,351	$ 2,586,349	$ 1,029,313	$ 177,720	$ 303,428	$ 130,366	$ 92,175
3	Proposed Rate of Return	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%
4	**Required Operating Income @ 8.20% ROR**	**$ 354,187**	**$ 212,081**	**$ 84,404**	**$ 14,573**	**$ 24,881**	**$ 10,690**	**$ 7,558**
5	**Operating Expenses**							
6	O&M and A&G Expenses	$ 715,943	$ 522,603	$ 152,903	$ 10,135	$ 14,582	$ 11,344	$ 4,377
7	Depreciation and Amortization Expense	170,518	111,318	36,287	5,953	9,500	4,547	2,912
8	Taxes Other than Income	15,249	9,392	3,369	670	979	522	317
9	Current Income Taxes	50,156	30,032	11,952	2,064	3,523	1,514	1,070
10	Gross-up Federal Income Tax	18,972	11,360	4,521	781	1,333	573	405
11	Gross-up State Utility Tax	7,314	4,380	1,743	301	514	221	156
12	Gross-up Bad Debts	1,712	1,602	107	0	2	-	1
13	**Total Operating Expenses**	$ 979,864	$ 690,687	$ 210,882	$ 19,904	$ 30,433	$ 18,720	$ 9,238
14	**Total Revenue Requirement**	**$ 1,334,051**	**$ 902,768**	**$ 295,286**	**$ 34,477**	**$ 55,315**	**$ 29,410**	**$ 16,796**
15	**Operating Revenues at Current Rates**							
16	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
17	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
18	Other Revenues	14,131	7,044	2,848	279	445	3,383	132
19	**Total Operating Revenues**	$ 1,234,682	$ 801,640	$ 271,880	$ 36,303	$ 59,236	$ 42,538	$ 23,085
20	**Revenue Deficiency/(Surplus)**	**$ 99,369**	**$ 101,128**	**$ 23,405**	**$ (1,827)**	**$ (3,922)**	**$ (13,128)**	**$ (6,288)**
21	**Required Rate Increase/(Decrease)**	**12.18%**	**20.38%**	**14.40%**	**-5.07%**	**-6.67%**	**-33.53%**	**-27.40%**
22	**Relative Rate Increase**	**1.00**	**1.67**	**1.18**	**-0.42**	**-0.55**	**-2.75**	**-2.25**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Results of ACOSS Using Seaboard Allocation: Relative Rate of Return at Current Rates (Dollars in Thousands)

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service (Rate IS)
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	
1	**Rate Base**							
2	Plant in Service	$ 6,676,559	$ 3,950,398	$ 1,494,970	$ 278,661	$ 586,563	$ 198,240	$ 167,727
3	Accumulated Reserve	(1,736,046)	(1,065,740)	(381,236)	(67,439)	(135,009)	(47,562)	(39,060)
4	Other Rate Base Items	(621,162)	(352,814)	(149,389)	(27,168)	(57,931)	(17,316)	(16,545)
5	**Total Gas Rate Base**	**$ 4,319,351**	**$ 2,531,844**	**$ 964,345**	**$ 184,055**	**$ 393,623**	**$ 133,361**	**$ 112,123**
6	**Operating Income**							
7	**Operating Revenues at Current Rates**							
8	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
9	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
10	Other Revenues	14,131	7,008	2,806	283	498	3,393	144
11	**Total Operating Revenues**	$ 1,234,682	$ 801,603	$ 271,838	$ 36,307	$ 59,290	$ 42,547	$ 23,097
12	**Operating Expenses**							
13	O&M and A&G Expenses	$ 715,943	$ 519,725	$ 149,967	$ 10,227	$ 17,526	$ 13,459	$ 5,039
14	Depreciation and Amortization Expense	170,518	109,647	34,349	6,122	12,069	4,849	3,482
15	Taxes Other than Income	15,249	9,211	3,168	683	1,221	595	371
16	Current Income Taxes	50,156	24,556	12,706	2,903	4,289	3,562	2,140
17	**Total Operating Expenses**	$ 951,866	$ 663,139	$ 200,191	$ 19,936	$ 35,105	$ 22,464	$ 11,031
18	**Total Operating Income**	**$ 282,817**	**$ 138,464**	**$ 71,648**	**$ 16,371**	**$ 24,185**	**$ 20,083**	**$ 12,065**
19	**Rate of Return on Rate Base ("ROR")**	**6.55%**	**5.47%**	**7.43%**	**8.89%**	**6.14%**	**15.06%**	**10.76%**
20	**Relative Rate of Return ("RROR")**	**1.00**	**0.84**	**1.13**	**1.36**	**0.94**	**2.30**	**1.64**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Results of ACOSS Using Seaboard Allocation: Required Increase at Equalized Rates (Dollars in Thousands)

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	(Rate IS)
1	**Required Income Under Company's Proposed ROR**							
2	Total Gas Rate Base	$ 4,319,351	$ 2,531,844	$ 964,345	$ 184,055	$ 393,623	$ 133,361	$ 112,123
3	Proposed Rate of Return	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%
4	**Required Operating Income @ 8.20% ROR**	**$ 354,187**	**$ 207,611**	**$ 79,076**	**$ 15,093**	**$ 32,277**	**$ 10,936**	**$ 9,194**
5	**Operating Expenses**							
6	O&M and A&G Expenses	$ 715,943	$ 519,725	$ 149,967	$ 10,227	$ 17,526	$ 13,459	$ 5,039
7	Depreciation and Amortization Expense	170,518	109,647	34,349	6,122	12,069	4,849	3,482
8	Taxes Other than Income	15,249	9,211	3,168	683	1,221	595	371
9	Current Income Taxes	50,156	29,400	11,198	2,137	4,571	1,549	1,302
10	Gross-up Federal Income Tax	18,972	11,121	4,236	808	1,729	586	492
11	Gross-up State Utility Tax	7,314	4,287	1,633	312	667	226	190
12	Gross-up Bad Debts	1,712	1,602	107	0	2	-	1
13	**Total Operating Expenses**	$ 979,864	$ 684,993	$ 204,658	$ 20,290	$ 37,784	$ 21,262	$ 10,876
14	**Total Revenue Requirement**	**$ 1,334,051**	**$ 892,604**	**$ 283,734**	**$ 35,383**	**$ 70,062**	**$ 32,198**	**$ 20,071**
15	**Operating Revenues at Current Rates**							
16	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
17	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
18	Other Revenues	14,131	7,008	2,806	283	498	3,393	144
19	**Total Operating Revenues**	$ 1,234,682	$ 801,603	$ 271,838	$ 36,307	$ 59,290	$ 42,547	$ 23,097
20	**Revenue Deficiency/(Surplus)**	**$ 99,369**	**$ 91,001**	**$ 11,896**	**$ (924)**	**$ 10,771**	**$ (10,349)**	**$ (3,026)**
21	**Required Rate Increase/(Decrease)**	**12.18%**	**18.34%**	**7.32%**	**-2.57%**	**18.32%**	**-26.43%**	**-13.18%**
22	**Relative Rate Increase**	**1.00**	**1.51**	**0.60**	**-0.21**	**1.50**	**-2.17**	**-1.08**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Alternative ACOSS:
Relative Rate of Return at Current Rates
(Dollars in Thousands)

Line No.	Account Description	Total Company	General Service: Residential (Rate R)	General Service: Non-Residential (Rate N)	Commercial and Industrial Delivery Service: Delivery Service (Rate DS)	Commercial and Industrial Delivery Service: Large Firm (Rate LFD)	Commercial and Industrial Delivery Service: Extended Large Firm (Rate XD Firm)	Interruptible Service (Rate IS)
1	**Rate Base**							
2	Plant in Service	$ 6,676,559	$ 3,985,846	$ 1,532,418	$ 276,888	$ 545,563	$ 197,518	$ 138,327
3	Accumulated Reserve	(1,736,046)	(1,073,638)	(389,555)	(67,056)	(125,968)	(47,268)	(32,561)
4	Other Rate Base Items	(621,162)	(356,334)	(153,125)	(26,983)	(53,797)	(17,333)	(13,590)
5	**Total Gas Rate Base**	**$ 4,319,351**	**$ 2,555,874**	**$ 989,739**	**$ 182,849**	**$ 365,798**	**$ 132,917**	**$ 92,175**
6	**Operating Income**							
7	**Operating Revenues at Current Rates**							
8	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
9	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
10	Other Revenues	14,131	7,023	2,822	282	482	3,391	132
11	**Total Operating Revenues**	$ 1,234,682	$ 801,618	$ 271,854	$ 36,306	$ 59,274	$ 42,546	$ 23,085
12	**Operating Expenses**							
13	O&M and A&G Expenses	$ 715,943	$ 520,662	$ 150,900	$ 10,208	$ 16,650	$ 13,145	$ 4,377
14	Depreciation and Amortization Expense	170,518	110,348	35,083	6,089	11,280	4,804	2,912
15	Taxes Other than Income	15,249	9,280	3,240	681	1,148	584	317
16	Current Income Taxes	50,156	24,301	12,447	2,911	4,548	3,617	2,332
17	**Total Operating Expenses**	$ 951,866	$ 664,591	$ 201,670	$ 19,890	$ 33,627	$ 22,150	$ 9,938
18	**Total Operating Income**	**$ 282,817**	**$ 137,027**	**$ 70,184**	**$ 16,417**	**$ 25,647**	**$ 20,396**	**$ 13,147**
19	**Rate of Return on Rate Base ("ROR")**	**6.55%**	**5.36%**	**7.09%**	**8.98%**	**7.01%**	**15.34%**	**14.26%**
20	**Relative Rate of Return ("RROR")**	**1.00**	**0.82**	**1.08**	**1.37**	**1.07**	**2.34**	**2.18**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Alternative ACOSS:
Required Increase at Equalized Rates
(Dollars in Thousands)

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service (Rate IS)
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	
1	**Required Income Under Company's Proposed ROR**							
2	Total Gas Rate Base	$ 4,319,351	$ 2,555,874	$ 989,739	$ 182,849	$ 365,798	$ 132,917	$ 92,175
3	Proposed Rate of Return	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%	8.20%
4	**Required Operating Income @ 8.20% ROR**	**$ 354,187**	**$ 209,582**	**$ 81,159**	**$ 14,994**	**$ 29,995**	**$ 10,899**	**$ 7,558**
5	**Operating Expenses**							
6	O&M and A&G Expenses	$ 715,943	$ 520,662	$ 150,900	$ 10,208	$ 16,650	$ 13,145	$ 4,377
7	Depreciation and Amortization Expense	170,518	110,348	35,083	6,089	11,280	4,804	2,912
8	Taxes Other than Income	15,249	9,280	3,240	681	1,148	584	317
9	Current Income Taxes	50,156	29,679	11,493	2,123	4,248	1,543	1,070
10	Gross-up Federal Income Tax	18,972	11,226	4,347	803	1,607	584	405
11	Gross-up State Utility Tax	7,314	4,328	1,676	310	619	225	156
12	Gross-up Bad Debts	1,712	1,602	107	0	2	-	1
13	**Total Operating Expenses**	$ 979,864	$ 687,125	$ 206,847	$ 20,215	$ 35,554	$ 20,885	$ 9,238
14	**Total Revenue Requirement**	**$ 1,334,051**	**$ 896,707**	**$ 288,005**	**$ 35,208**	**$ 65,549**	**$ 31,785**	**$ 16,796**
15	**Operating Revenues at Current Rates**							
16	Sales Revenue	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
17	Gas Cost Revenue	404,972	298,487	106,485	-	-	-	-
18	Other Revenues	14,131	7,023	2,822	282	482	3,391	132
19	**Total Operating Revenues**	$ 1,234,682	$ 801,618	$ 271,854	$ 36,306	$ 59,274	$ 42,546	$ 23,085
20	**Revenue Deficiency/(Surplus)**	**$ 99,369**	**$ 95,089**	**$ 16,151**	**$ (1,098)**	**$ 6,276**	**$ (10,761)**	**$ (6,288)**
21	**Required Rate Increase/(Decrease)**	**12.18%**	**19.17%**	**9.94%**	**-3.05%**	**10.67%**	**-27.48%**	**-27.40%**
22	**Relative Rate Increase**	**1.00**	**1.57**	**0.82**	**-0.25**	**0.88**	**-2.26**	**-2.25**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Company's Proposed Revenue Allocation (Dollars in Thousands)

Witness: Deupree
Docket No. R-2025-3059523
Exhibit MWD-6

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	(Rate IS)
1	**Allocated Cost of Service Study Results**							
2	**Total Rate Base**	**$ 4,319,351**	**$ 2,586,349**	**$ 1,029,313**	**$ 177,720**	**$ 303,428**	**$ 130,366**	**$ 92,175**
3	**Gas Operating Revenues**							
4	Gas Rate Revenues	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
5	Other Operating Revenues	419,103	305,531	109,333	279	445	3,383	132
6	**Total Gas Operating Revenues**	**$ 1,234,682**	**$ 801,640**	**$ 271,880**	**$ 36,303**	**$ 59,236**	**$ 42,538**	**$ 23,085**
7	**Total Gas Operating Expenses**	**$ 951,866**	**$ 667,162**	**$ 204,507**	**$ 19,702**	**$ 30,209**	**$ 20,348**	**$ 9,938**
8	**Present Net Operating Income (for Ratemaking Purposes)**	**$ 282,817**	**$ 134,478**	**$ 67,373**	**$ 16,601**	**$ 29,027**	**$ 22,190**	**$ 13,147**
9	**Rate of Return**	**6.55%**	**5.20%**	**6.55%**	**9.34%**	**9.57%**	**17.02%**	**14.26%**
10	**Relative Rate of Return**	**1.00**	**0.79**	**1.00**	**1.43**	**1.46**	**2.60**	**2.18**
11	**Proposed Revenue Increase**							
12	**Proposed Revenue Increase**							
13	Current Gas Operating Revenues	$ 1,234,682						
14	Proposed Gas Operating Revenues	1,334,051						
15	**Proposed Revenue Increase**	**$ 99,369**						
16	**Step One Increase**							
17	Rate Decrease to XD and IS Classes						-0.16%	-0.32%
18	Revenue Decrease	$ (138)					$ (64)	$ (73)
19	Revenue Remaining after Step One	$ 99,506						
20	**Step Two Increase**							
21	Rate Increase to N, DS, and LFD Classes			14.39%	1.97%	1.25%		
22	Revenue Increase	$ 24,830		$ 23,386	$ 708	$ 736		
23	Revenue Remaining after Step Two	$ 74,677						
24	**Step Three Increase**							
25	Remaining Increase to Residential Class	$ 74,677	$ 74,677					
26	Revenue Remaining after Step Three	-						
27	**Proposed Revenues Increase by Class**	**$ 99,369**	**$ 74,677**	**$ 23,386**	**$ 708**	**$ 736**	**$ (64)**	**$ (73)**
28	Current Gas Revenues	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
29	Proposed Revenue Increase	99,369	74,677	23,386	708	736	(64)	(73)
30	**Proposed Gas Rate Revenue**	**$ 914,948**	**$ 570,785**	**$ 185,933**	**$ 36,732**	**$ 59,528**	**$ 39,090**	**$ 22,879**
31	**Proposed Revenue Change**	**12.18%**	**15.05%**	**14.39%**	**1.97%**	**1.25%**	**-0.16%**	**-0.32%**
32	**Relative Proposed Rate Increase**	**1.00**	**1.24**	**1.18**	**0.16**	**0.10**	**-0.01**	**-0.03**

Source: Company's Response to I&E-RS-6-D.1.

Summary of Results of Alternative Revenue Allocation (Dollars in Thousands)

Witness: Deupree
Docket No. R-2025-3059523
Exhibit MWD-7

Line No.	Account Description	Total Company	General Service		Commercial and Industrial Delivery Service			Interruptible Service
			Residential (Rate R)	Non-Residential (Rate N)	Delivery Service (Rate DS)	Large Firm (Rate LFD)	Extended Large Firm (Rate XD Firm)	(Rate IS)
1	**Cost of Service Results**							
2	**Total Rate Base**	**$ 4,319,351**	**$ 2,555,874**	**$ 989,739**	**$ 182,849**	**$ 365,798**	**$ 132,917**	**$ 92,175**
3	**Gas Operating Revenues**							
4	Gas Rate Revenues	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
5	Other Operating Revenues	419,103	305,509	109,307	282	482	3,391	132
6	**Total Gas Operating Revenues**	**$ 1,234,682**	**$ 801,618**	**$ 271,854**	**$ 36,306**	**$ 59,274**	**$ 42,546**	**$ 23,085**
7	**Total Gas Operating Expenses**	**$ 951,866**	**$ 664,591**	**$ 201,670**	**$ 19,890**	**$ 33,627**	**$ 22,150**	**$ 9,938**
8	**Present Net Operating Income (for Ratemaking Purposes)**	**$ 282,817**	**$ 137,027**	**$ 70,184**	**$ 16,417**	**$ 25,647**	**$ 20,396**	**$ 13,147**
9	**Rate of Return**	**6.55%**	**5.36%**	**7.09%**	**8.98%**	**7.01%**	**15.34%**	**14.26%**
10	**Relative Rate of Return**	**1.00**	**0.82**	**1.08**	**1.37**	**1.07**	**2.34**	**2.18**
11	**Proposed Revenue Increase**							
12	**Proposed Revenue Increase**							
13	Current Gas Operating Revenues	$ 1,234,682						
14	Proposed Gas Operating Revenues	1,334,051						
15	**Proposed Revenue Increase**	**$ 99,369**						
16	**Revenue Increase at Equal Rates of Return**							
17	Current Gas Operating Revenues	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
18	Revenue Increase at Equal Rates of Return	99,369	95,089	16,151	(1,098)	6,276	(10,761)	(6,288)
19	**Total Revenues at Equal Rates of Return**	**$ 914,948**	**$ 591,197**	**$ 178,698**	**$ 34,926**	**$ 65,067**	**$ 28,394**	**$ 16,665**
20	**Revenue Increase**	**12.18%**	**19.17%**	**9.94%**	**-3.05%**	**10.67%**	**-27.48%**	**-27.40%**
21	**Relative Revenue Increase**	**1.00**	**1.57**	**0.82**	**-0.25**	**0.88**	**-2.26**	**-2.25**
22	**Step One Mitigation**							
23	Maximum Increase at 1.15 times System Average	14.01%	14.01%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Total Step One Mitigation	$ 69,512	$ 69,512	$ -	$ -	$ -	$ -	$ -
25	Remaining Revenue Increase after Step One	$ 29,857						
26	**Step Two Mitigation**							
27	No Rate Decrease	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	Total Step Two Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Remaining Revenue Increase after Step Two	$ 29,857						
30	**Step Three Mitigation**							
31	Basis for Step Three	$ 221,339	$ -	$ 162,547	$ -	$ 58,792	$ -	$ -
32	Equal Allocation of Remaining Revenue Requirement	$ 29,857	$ -	$ 21,926	$ -	$ 7,931	$ -	$ -
33	Remaining Revenue Increase after Step Three	$ -						
34	**Proposed Revenues Increase by Class**	**$ 99,369**	**$ 69,512**	**$ 21,926**	**$ -**	**$ 7,931**	**$ -**	**$ -**
35	Current Gas Rate Revenues	$ 815,579	$ 496,109	$ 162,547	$ 36,024	$ 58,792	$ 39,155	$ 22,953
36	Proposed Revenue Increase	99,369	69,512	21,926	-	7,931	-	$ -
37	**Proposed Gas Rate Revenue**	**$ 914,948**	**$ 565,620**	**$ 184,474**	**$ 36,024**	**$ 66,722**	**$ 39,155**	**$ 22,953**
38	**Proposed Revenue Change**	**12.18%**	**14.01%**	**13.49%**	**0.00%**	**13.49%**	**0.00%**	**0.00%**
39	**Relative Proposed Rate Increase**	**1.00**	**1.15**	**1.11**	**0.00**	**1.11**	**0.00**	**0.00**

Source: Company's Response to I&E-RS-6-D.1.

Analysis of Customer-Related Costs
(Dollars in Thousands)

Witness: Deupree
Docket No. R-2025-3059523
Exhibit MWD-8

Line No.	Account Description	General Service Residential (RS)	General Service Non-Residential (Rate N)	Commercial Delivery Service Delivery Service (Rate DS)	Commercial Delivery Service Large Firm (Rate LFD)
1	**Customer-Related Costs per Company's ACOSS**				
2	**Return on Customer-Related Rate Base**				
3	380 - Services	$1,695,188	$ 227,010	$ 7,850	$ 4,951
4	381 - Meters	99,547	94,556	10,619	9,102
5	382 - Meter installations	69,705	66,211	7,436	6,374
6	383 - House regulators	9,060	1,214	-	-
7	384 - House regulatory installations	15,722	2,108	-	-
8	Total Customer-Related Plant in Service	$1,889,222	$ 391,100	$ 25,905	$ 20,426
9	System Average Return on Rate Base	6.55%	6.55%	6.55%	6.55%
10	Before Tax Return on Customer-Related Rate Base	$ 123,700	$ 25,608	$ 1,696	$ 1,337
11	Tax Gross-up Factor	1.398	1.398	1.398	1.398
12	**After Tax Return on Customer-Related Rate Base**	**$ 172,983**	**$ 35,810**	**$ 2,372**	**$ 1,870**
13	**Customer-Related Expenses**				
14	874 - Services Expenses	$ 13,983	$ 1,872	$ 65	$ 41
15	878 - Meters and House Regulator Expenses	$ 1,679	$ 1,595	$ 179	$ 154
16	879 - Customer Installation Expenses	$ 1,526	$ 1,450	$ 163	$ 140
17	892 - Maintenance of Services	$ 592	$ 79	$ 3	$ 2
18	893 - Maintenance of Meters and House Regulators	$ 18	$ 17	$ 2	$ 2
19	901-905 - Customer Account Expenses (minus Universal Service Program)	$ 47,539	$ 4,403	$ 64	$ 50
20	906-910 - Customer Service and Information Expenses	$ 12,345	$ 942	$ 401	$ 977
21	912-913 - Sales Expenses	$ 1,164	$ 128	$ -	$ -
22	**Total Customer-Related O&M Expenses**	**$ 78,846**	**$ 10,487**	**$ 876**	**$ 1,365**
23	**Customer-Related Depreciation Expense**				
24	Total Distribution Plant in Service	$3,487,119	$ 1,471,092	$ 243,364	$ 414,507
25	Total Customer-Related Plant in Service	1,889,222	391,100	25,905	20,426
26	Percent Customer-Related	54.2%	26.6%	10.6%	4.9%
27	Total Distribution Depreciation Expense	$ 78,254	$ 29,562	$ 4,483	$ 7,339
28	Percent Customer-Related	54.2%	26.6%	10.6%	4.9%
29	**Customer-Related Depreciation Expense**	**$ 42,396**	**$ 7,859**	**$ 477**	**$ 362**
30	**Total Class Functionalized Customer-Related Costs**	**$ 294,225**	**$ 54,157**	**$ 3,725**	**$ 3,597**
31	Number of Customers	634,252	69,690	1,305	638
32	**Monthly Customer-Related Costs/Customer**	**$ 38.66**	**$ 64.76**	**$ 237.90**	**$ 469.81**
33	**Current Monthly Customer Charge/Customer**	**$ 16.25**	**$ 36.42**	**$ 300.00**	**$ 670.00**
34	**Relationship of Customer Charge Revenues to Customer-Related Costs**	**42.0%**	**56.2%**	**126.1%**	**142.6%**

Source: Company's Response to I&E-RS-6-D.1.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: */s/ Michael Deupree*
Michael Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3059523
v.	:	
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY

OF

MICHAEL DEUPREE

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2026

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding on April 13, 2026, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to elements of the rebuttal testimony of Cyndee S. Fang, Jessica R. Rogers, and John D. Taylor on behalf of UGI Utilities, Inc. – Gas Division ("UGI-G" or the "Company"). Specifically, I will respond to UGI-G's discussion of macroeconomic issues, its proposed weather normalization adjustment, as well as issues concerning its proposed allocated cost of service study ("ACOSS") and rate design.

II. MACROECONOMIC ISSUES

Q. PLEASE SUMMARIZE UGI-G WITNESS ROGERS' STATEMENTS RESPONDING TO YOUR DISCUSSION OF MACROECONOMIC ISSUES IN ITS REBUTTAL TESTIMONY.

A. UGI-G witness Rogers states that I encourage the Commission to evaluate the Company's proposed rate relief "entirely" on macroeconomic circumstances.[1] The Company argues that my testimony raising concerns related to current inflationary pressures for Pennsylvania ratepayers is contrary to OCA's long-opposed position concerning the use of general inflationary factors or

[1] Rebuttal Testimony of Jessica R. Rogers at 13:7-8.

other generic economic data as the basis for individual cost claims.[2] Finally, the Company argues that I misconstrue the scope of utility regulations, which it claims is to ensure that utility rates are just and reasonable based on the prudent costs of providing utility service.[3]

Q. DID YOU ARGUE IN YOUR DIRECT TESTIMONY THAT UTILITY REQUESTED RATE INCREASES SHOULD BE "ENTIRELY" EVALUATED ON MACROECONOMIC ISSUES?

A. No. My direct testimony explains that utility rate increases do not occur in a vacuum, a position the Company agrees with.[4] To this end, my direct testimony contains an extensive discussion of current macroeconomic conditions affecting Pennsylvanians. I specifically found that average Pennsylvanians are still struggling with lingering inflation concerns while also facing potential additional concerns due to current hostilities in the Persian Gulf.[5] This while the Company's parent company has seen increasing stock prices for its shareholders and no obvious market distress.[6] Rather than arguing that the Company's proposed rate increase, or any other proposed utility rate increase, should be "entirely" evaluated on these macroeconomic issues, I recommend that the Commission take these concerns, including consumer affordability concerns, into consideration when determining just and reasonable rates for the Company.[7]

Q. DID YOUR DIRECT TESTIMONY SUPPORT A SECONDARY POSITION OF A RATE DECREASE FOR THE COMPANY?

A. No. The Company states in its rebuttal testimony that I supported a secondary position of a rate decrease for the Company in my direct testimony, which the Company argues would be

[2] Rebuttal Testimony of Jessica R. Rogers at 15:17-20.
[3] Rebuttal Testimony of Cyndee S. Fang at 5:18-20.
[4] Rebuttal Testimony of Jessica R. Rogers at 16:9.
[5] Direct Testimony of Michael W. Deupree at 20:7-9.
[6] Direct Testimony of Michael W. Deupree at 20:9-10.
[7] Direct Testimony of Michael W. Deupree at 20:10-11.

unreasonable and confiscatory.[8] No such position was laid out in my direct testimony or here in my surrebuttal testimony. Ms. Jennifer L. Rogers presents OCA's recommended overall revenue sufficiency for UGI-G.

Q. IS IT A RECOGNIZED ELEMENT OF UTILITY REGULATION THAT POLICY MAKERS SHOULD CONSIDER MACROECONOMIC CONDITIONS WHEN DETERMINING JUST AND REASONABLE RATES?

A. Yes. Company witness Fang argues that the Commission's statutory obligation is to ensure that utility rates are just and reasonable based on prudent costs.[9] While I have been informed that OCA will address legal arguments in its brief, from a policy perspective it is generally accepted that fixing just and reasonable rates involves a balancing of utility and consumer interests, as explained by the U.S. Supreme Court in its landmark 1944 decision in *Federal Power Commission v. Hope Natural Gas Company*.[10] To this end, I argue that the Commission should require some level of shared burden, balancing consumer affordability concerns with the financial interests of the Company.[11]

Q. HAVE OTHER PROMINENT FIGURES EXPRESSED SIMILAR CONCERNS IN PENNSYLVANIA SUBSEQUENT TO THE FILING OF YOUR DIRECT TESTIMONY?

A. Yes. On April 29, 2026, Governor Josh Shapiro issued an open letter to the Commission arguing that customers across the Commonwealth are experiencing higher utility costs, and that rising utility bills have become a driver of inflation.[12] Governor Shapiro stated that utilities must seek ways of procuring capital to finance investments in more affordable ways, conscious of the

[8] Rebuttal Testimony of Jessica R. Rogers at 15:5-6.
[9] Rebuttal Testimony of Cyndee S. Fang at 5:18-20.
[10] *See*, *Federal Power Com'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); The rate-making process under the [Natural Gas Act], i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interest.
[11] Direct Testimony of Michael W. Deupree at 20:10-11.
[12] Open Letter dated April 29, 2026, from Governor Josh Shapiro to Utility Leaders, at 1.

utility burdens facing many consumers across the Commonwealth.[13] In this, Governor Shapiro's message appears to mirror my general argument that the Commission should balance consumer affordability concerns with the financial interests of utilities when determining just and reasonable rates for the Company. I have attached Governor Shapiro's letter to this surrebuttal testimony as Exhibit MWD-9. Likewise, subsequent to withdrawing a proposed increase in rates for its electric and gas operations, David Vahos, the president and chief executive officer ("CEO") of PECO Energy Company ("PECO") stated that PECO's decision to withdraw was based on customer affordability considerations. I have attached PECO's press release to this surrebuttal testimony as Exhibit MWD-10.

> While our filing with the [Commission] would have provided needed improvements in safe and reliable energy delivery, we recognize that Pennsylvanians are struggling with basic necessities like gas, food, and energy and have decided to withdraw our proposal.[14]

Q. IS IT INCONSISTENT TO ASK THE COMMISSION TO CONSIDER LARGER MACROECONOMIC CONCERNS WHEN EVALUATING THE COMPANY'S PROPOSED RATE INCREASE IN LIGHT OF THE OCA'S HISTORIC OPPOSITION TO USE OF BROAD INFLATION FACTORS IN DETERMINING INDIVIDUAL COSTS?

A. No. The Company attempts to argue that historic differences of opinion on the relevance of using broad inflationary factors to determine individual cost forecasts is equivalent to recognizing that consumer price inflation negatively affects consumer affordability. The two concerns are not equivalent. The first represents differences of opinion regarding the robustness of mechanical calculations of filed utility costs. I am advised by counsel for the OCA that the use

[13] Open Letter dated April 29, 2026, from Governor Josh Shapiro to Utility Leaders, at 1.
[14] PECO Communications (April 16, 2026), "PECO Withdraws Electric and Natural Gas Regulatory Rate Review Filings to Prioritize Customer Affordability."

of inflationary factors to adjust individual, line item expenses bears directly on whether a utility has presented sufficient evidence to meet its burden of proof regarding specific expense adjustments.[15] The second merely asks the Commission to recognize the reality that average customers are facing increased costs from several segments of the economy, and that rising utility costs may negatively contribute to these already increasing costs.

Q. HOW DO YOU RESPOND TO THE COMPANY WITNESS ROGER'S CLAIM THAT THE COMPANY IS ALSO "EXPERIENCING INFLATIONARY PRESSURES THAT ARE INCREASING [ITS] COSTS"?[16]

A. As I stated in my direct testimony, increased operating costs to UGI-G caused by the current inflationary environment has not caused noticeable negative impacts on UGI-G's shareholder income or UGI-G's parent company stock price. This is partially because the Company has the opportunity to request rate increases from the Commission to account for these increased operating costs caused by inflation. Indeed, the Commission should recognize the Company's requested $99.4 million increase in revenues comes immediately on the heels of the Commission approving a $69.5 million increase in revenues in September 2025. The Commission must balance the pressure inflation places on utility operating costs with the general economic effects inflation places on customer affordability, rather than shifting all inflationary risks from utilities to ratepayers.

Q. DOES THE COMPANY HAVE COMMISSION-APPROVED MECHANISMS TO ADDRESS UTILITY AFFORDABILITY?

A. Yes. The Company references its Universal Service Programs ("USPs"), including the Consumer Assistance Program ("CAP"), as mechanisms that are designed to address utility

[15] 66 Pa. C.S. § 315(e).
[16] Rebuttal Testimony of Jessica R. Rogers at 16:9-20.

affordability by reducing arrearages and maintaining service for low-income households.[17] While USPs serve an important role in addressing affordability concerns for low-income ratepayers, the Commission should recognize that the current affordability crisis caused by years of high general inflation is impacting all Pennsylvanians, even if the effects of said crisis fall disproportionately on low-income households. Addressing affordability concerns only through increased funding of USP programs or expanded access to said programs amounts to nothing more than a Band-Aid fix to a larger problem.

Q. WHAT IS YOUR RECOMMENDATION BASED ON CURRENT MACROECONOMIC CONDITIONS?

A. I continue to recommend the Commission take into consideration current macroeconomic conditions, including consumer affordability concerns, when determining just and reasonable rates for the Company. Average Pennsylvanians are struggling with lingering inflation concerns while also facing potential additional concerns due to fallout from the conflict in the Persian Gulf. Meanwhile, the Company has seen increasing stock prices for its shareholders and no obvious market distress. The Commission, in particular, should require some level of shared burden, balancing consumer affordability concerns with the financial interests of the Company. Governor Shapiro's recent open letter raising similar concerns only strengthens the urgency for the Commission to recognize these larger concerns, and the broader context surrounding the Company's proposed rate increase.

III. <u>WEATHER NORMALIZATION ADJUSTMENT (WNA)</u>

Q. PLEASE SUMMARIZE THE COMPANY WITNESS TAYLOR'S RESPONSE TO INTERVENORS' CONCERNS REGARDING THE COMPANY'S WNA.

[17] Rebuttal Testimony of Cyndee S. Fang at 7:7-11.

A. The Company argues that the WNA has produced net WNA charges due to warmer than normal weather conditions since November 2022, when the WNA went into effect, and the use of a 15-year average to calculate normal weather conditions.[18] The Company argues that the fact that the presence of net WNA charges does not demonstrate that the WNA is structurally biased against customers or failing to function as designed.[19] The Company also takes issue with my arguments that the WNA is not needed in the context of other mechanisms at the Company's disposal to address regulatory lag, arguing that the WNA is not designed to address regulatory lag.[20]

Q. DO YOU AGREE WITH THE COMPANY'S CHARACTERIZATION OF THE WNA?

A. No. As discussed in my direct testimony, the WNA has produced over $63.1 million in net revenue for the Company since the mechanism was introduced by the Company in November 2022.[21] Indeed, for the period from November 2022 through February 2026, only in six of the 28 months (or 21 percent) that the WNA has been in place did ratepayers see credits under the mechanism. The Commission should furthermore recognize that this trend of WNA charges will likely continue in the remaining months of the 2025-2026 heating season (i.e. the months of March and April) due to the abnormally warm spring Pennsylvania has experienced. Rather than being a symmetric mechanism designed to produce both credits and charges for ratepayers, the WNA has functioned as an asymmetric mechanism.

Q. IS IT SURPRISING THAT THE COMPANY'S WNA MECHANISM HAS RESULTED IN DISPROPORTIONATELY PRODUCED SURCHARGES FOR RATEPAYERS?

[18] Rebuttal Testimony of John D. Taylor at 32:16-18.
[19] Rebuttal Testimony of John D. Taylor at 32:18-21.
[20] Rebuttal Testimony of John D. Taylor at 32:4-16.
[21] Direct Testimony of Michael W. Deupree at 34, Table 1.

A. No. Table 1 provides a summary of the results provided in a report prepared on the behalf of several energy advocacy groups in the Pacific Northwest by Graceful Systems that was purportedly designed to support the adoption of revenue decoupling.[22] The table provides the number of instances in which there were observed rate increases or rate decreases for electric and gas utilities under revenue decoupling over a 10-year period. The table shows 72 percent of the gas utilities in the sample and 57 percent of all the electric utilities in the same sample had reconciliations resulting in rate increases instead of rate decreases. This stands in contradiction to the typical utility assertion that decoupling will yield results that are symmetrical (i.e., will lead to equal rate increases and decreases). The results are even more prevalent when examining large reconciliations. Only three percent of all survey reconciliations associated with gas decoupling programs resulted in refunds to customers greater than three percent. This is approximately one-sixth of the 19 percent of surveyed gas decoupling reconciliations that resulted in surcharges to customers greater than three percent.

Table 1: Summary of Lesh Report

Refund/Surcharge	Number of Reconciliations			Share of All Reconciliations		
	Gas	Electric	Total	Gas	Electric	Total
Refund Percent						
Greater than 3 percent	2	0	2	3.1%	0.0%	2.3%
Less than or equal to 3 percent	1	3	4	1.5%	13.0%	4.5%
Less than or equal to 2 percent	2	1	3	3.1%	4.3%	3.4%
Less than or equal to 1 percent	13	6	19	20.0%	26.1%	21.6%
Total				**27.7%**	**43.5%**	**31.8%**
Surcharge Percent						
Less than 1 percent	23	7	30	35.4%	30.4%	34.1%
Less than 2 percent	7	4	11	10.8%	17.4%	12.5%
Less than 3 percent	5	2	7	7.7%	8.7%	8.0%
Greater than 3 percent	12	0	12	18.5%	0.0%	13.6%
Total				**72.3%**	**56.5%**	**68.2%**
Total Decoupled Utilities	**65**	**23**	**88**	**100.0%**	**100.0%**	**100.0%**

Source: Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling

[22] *See,* Pamela Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review (2009).

Q. DO YOU AGREE WITH THE COMPANY'S ASSERTION THAT THE WNA SHOULD BE VIEWED INDEPENDENTLY OF REGULATORY LAG?

A. No. The Company argues that, since it did not explicitly tie its proposal to extend the current WNA mechanism pilot program for another five-year period, that discussions on the role regulatory lag plays in the regulatory process are somehow inappropriate.[23] However, the Commission should recognize that the WNA allows the Company to recover declines in revenues caused by falling use per customer ("UPC") between rate cases due to the growing prevalence of moderating weather. The Company itself described the WNA as helping to ensure that it recovers fixed costs independently of changes in volumetric usage,[24] and discussed moderating weather trends at length in its direct testimony.[25] Indeed, the Company argued that "even though UGI Gas' distribution costs are fixed, there is a risk of over- and under-recovery for the vast majority of costs, resulting in the need for the WNA."[26] If these risks are not symmetric, which historic recoveries through the WNA demonstrate, the WNA in practice acts as a means to shift volumetric risks between rate cases from the Company to its customers.

Q. DID THE COMPANY ADDRESS ANY OF YOUR PROPOSED ALTERNATIVE MODIFICATIONS TO THE WNA?

A. Yes. The Company opposes both expanding the WNA deadband to five percent and eliminating the month of October from the WNA. The Company argues that increasing the current WNA deadband from three to five percent would materially weaken the WNA by expanding the range of weather variation for which no adjustment is made, and as a result would harm both the customers and the Company by omitting smaller deviations in weather that still have meaningful

[23] Direct Testimony of Jessica R. Rogers at 26:6-8.
[24] *See*, Direct Testimony of John D. Taylor at 36:6 to 37:3.
[25] *See*, Direct Testimony of John D. Taylor at Exhibit JDT-2.
[26] Direct Testimony of John D. Taylor at 37:1-3.

effects.[27] Likewise, the Company opposes removing the month of October from the WNA, arguing that there are still some heating requirements during that month.[28]

Q. DO YOU AGREE THAT INCREASING THE WNA DEADBAND FROM THREE TO FIVE PERCENT WOULD HARM BOTH CUSTOMERS AND THE COMPANY BY OMITTING SMALLER DEVIATIONS IN WEATHER THAT STILL HAVE MEANINGFUL EFFECTS?

A. No. As demonstrated above, mechanisms like the WNA predominantly result in surcharges in the utility's favor. This is true for the Company as well since the WNA has resulted in more than $63.1 million in revenues for the Company since it was first implemented in November 2022. So, increasing the WNA deadband to five percent would provide for additional protection to ratepayers from minor deviations from normal weather. It would also place the WNA in-line with the recently modified WNA mechanisms for Columbia Gas.

Q. DO YOU AGREE WITH THE COMPANY THAT THE PRESENCE OF HEATING REQUIREMENTS DURING A MONTH SHOULD BE THE BASIS FOR INCLUSION IN THE WNA?

A. No. The Company's finding that there are some customer heating requirements during the months of October and April is irrelevant to the question at hand. The Commission need not, nor should it, shift all volumetric weather-related risks from the Company to customers. As shown in Table 2, very little of the annual average customer heating requirements are included in the month of October. Specifically, the month of October represents 6 percent of the total annual heating requirement in Pennsylvania as represented by HDDs. Indeed, the months of November through April contain approximately 89 percent of all Pennsylvania heating requirements.

[27] Rebuttal Testimony of John D. Taylor at 46:8-19.
[28] Rebuttal Testimony of John D. Taylor at 47:4-19.

Table 2: Average 10-Year Pennsylvania Heating Degree Days

Month	10-Year (2016-2025) Average Heating Degree Day	Percent of Total
January	1,078	20%
February	858	16%
March	720	14%
April	427	8%
May	177	3%
June	31	1%
July	3	0%
August	11	0%
September	69	1%
October	314	6%
November	674	13%
December	960	18%
Total	**5,322**	**100%**

Note: Values represent a simple average of UGI-G weather stations
Source: National Oceanic and Atmospheric Administration, National Centers for Environmental Information, GHCN-Daily.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE WNA?

A. I continue to recommend the following from my direct testimony:

- The Commission should affirmatively discontinue UGI-G's current WNA mechanism. The mechanism has failed to produce balanced outcomes for ratepayers, functioning as an asymmetric surcharge on customers' bills for the three years the mechanism has been in operation, even though the mechanism was designed as a pilot to symmetrically provide both surcharges and credits to customers. The WNA is also not required to address regulatory lag concerns of the Company given the Company's use of a fully projected future test year ("FPFTY") and distribution system improvement charge ("DSIC").
- If the Commission decides to continue the WNA, I recommend that it be continued as a three-year pilot program rather than being adopted as a permanent mechanism. This will allow the Commission the opportunity to routinely reevaluate the WNA to ensure that the mechanism is not producing negative outcomes for ratepayers. I further recommend that the Commission increase the deadband from three percent to five percent and eliminate the month of October from the WNA period. This would strengthen ratepayer protections and would furthermore make the Company's WNA pilot consistent with the recent WNA pilot that the Commission approved for Columbia Gas of Pennsylvania (Columbia Gas).

IV. ALLOCATED COST OF SERVICE STUDY

Q. WHAT IS THE COMPANY WITNESS TAYLOR'S RESPONSE TO YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ACOSS?

A. The Company continues to argue for its proposed Average and Excess ("A&E") cost allocation method to allocate costs associated with distribution mains. Specifically, the Company argues that an A&E cost allocation recognizes that peak-related demand remains the dominant cost driver in determining how large the distribution system must be.[29] The Company furthermore argues that my proposed alternative peak and average ("P&A") cost allocation method using the Company's system load factor, "represents a fundamental misunderstanding of how distribution mains are designed and what drives their cost."[30] The Company also argues that the P&A methodology "inherently double-counts average demand."[31]

Q. DO YOU AGREE THAT PEAK-RELATED DEMAND IS THE ONLY COST DRIVER OF UTILITY SYSTEM INVESTMENTS IN DISTRIBUTION MAINS?

A. No. The Company insinuates that peak-related demand is the only, or at least represents the vast majority of, cost driver for investments into distribution mains, other than customer-related costs, which the Company correctly does not include in its allocation of the cost of mains. The reality is that natural gas facilities are used year-round, and utility system planners must consider non-peak use in addition to peak demand use when designing distribution systems. This was recognized by the Federal Power Commission ("FPC") in 1952, in its decision involving the Atlantic Seaboard Corporation.[32] Indeed, the FPC found that "both capacity and annual use are important considerations in the conception of the project," and that therefore both capacity and throughput are cost causation factors driving capital outlays for a pipeline project.[33]

> … A pipeline would not normally be built to supply peak service, that is to say, service on the peak days only… pipelines are built to

[29] Rebuttal Testimony of John D. Taylor at 11:17-18.
[30] Rebuttal Testimony of John D. Taylor at 12:4-9.
[31] Rebuttal Testimony of John D. Taylor at 13:2-12.
[32] Direct Testimony of Michael W. Deupree at 50:18-24, *citing* Re: Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43.
[33] Re: Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43.

> supply service not only on the few peak days but on all days throughout the year… Both capacity and volume, therefore, are what are known as cost factors or incidences in respect to the capital outlay for a pipeline project. It follows that reasonably accurate results can be achieved only by allocating the fixed expenses flowing from the capital outlay to both operating functions, viz., capacity and volume.
>
> …
>
> To reiterate – and emphasize – fixed costs or expenses are incurred for both peak use and annual use in respect to both demand and volumetric functions. They are important cost factors in respect to both services. To achieve a reasonably equitable result they must be apportioned to both services.[34]

Q. HAS THE COMMISSION ITSELF RECENTLY WEIGHED IN ON THE NEED TO INCLUDE VOLUMETRIC CONSIDERATIONS WHEN CLASSIFYING COSTS ASSOCIATED WITH DISTRIBUTION MAINS AS CUSTOMER-RELATED?

A. Yes. In its recent 2025 decision regarding proposed rates for Columbia Gas, the Commission adopted a P&A cost allocation method to classify and allocate costs associated with natural gas distribution mains.[35] In reaching its decision, the Commission directly found that investments in natural gas distribution mains are driven by both annual and peak demands.[36]

> Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand [ACOSS]. The basic reason Columbia invests in its distribution system is to meet the annual demands for gas by customers.[37]

[34] R.L. Conkling (2011), Energy Pricing: Economics and Principles, pages 96-97; *citing* Re: Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43, *emphasis added.*
[35] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2025-3053499, Opinion and Order at 255.
[36] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2025-3053499, Opinion and Order at 255.
[37] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2025-3053499, Opinion and Order at 255, *emphasis added.*

Q. ARE THERE PRACTICAL CONSIDERATIONS TO INCLUDING NON-PEAK USE IN ALLOCATION OF DISTRIBUTION MAIN INVESTMENTS?

A. Yes. The Commission should recognize what excluding non-peak use considerations from allocations of costs associated with distribution mains would mean for interruptible service ("IS") customers. Cost of service analysts typically do not include any peak-day demand requirement for IS customers under the reasonable presumption that the utility would utilize its contractual ability to interrupt service to these customers during peak-day system events. Indeed, the Company in the current proceeding excluded IS from its estimation of peak-day natural gas requirements.[38] If costs associated with natural gas mains were allocated solely on the basis of contribution to peak day demand requirements, these customers would not bear any costs associated with a capital outlay comprising more than $2.5 billion of the Company's total test year ratebase of approximately $4.3 billion, including depreciation expense, return on investment, income taxes, etc. Indeed, it was partially due to concerns related to IS customers that the FPC in its 1952 decision rejected arguments to allocate costs associated with pipeline investments solely on the basis of peak demand considerations, finding it problematic that an IS customers could use a pipeline system for 360 days of the year and be excluded from any cost responsibility associated with the construction of the pipeline due to being interrupted for five or so days.[39]

> If fixed expenses are assigned wholly to the demand or capacity function, then gas service which is interrupted on peak days will not share in any of the fixed costs. Conceivably under such an allocation large quantities of natural gas could be sold to industrials 360 days of the year and interrupted on five or so peak days, and such gas would bear none of the costs incurred in constructing the pipeline facility. In other words, under a strict application of this theory [the peak-responsibility method], the interruptible service would not bear any depreciation expense, return, income taxes, or any part of

[38] Company's Response to I&E-RS-6-D.1.

[39] *Re: Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation*, Federal Power Commission Docket No. 11. F.P.C. 43.

> the other fixed expenses associated with the capital outlay. This would be so even though the capital outlay made the interruptible service possible by providing the means of transportation used extensively by such assumed interruptible service…[40]

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT THAT THE P&A COST ALLOCATION METHODOLOGY "DOUBLE COUNTS" VOLUMETRIC USE?

A. No. The Company states an often-repeated claim that P&A cost allocation methodologies "double counts" class average demand consumption during peak demand periods.[41] The Company, consistent with others who extol the supposed superiority of the A&E cost allocation approach, argue that the A&E cost allocation approach solves this double counting problem by using "excess demand" rather than using peak demand requirements in its construction.[42] However, in using the excess component only, the A&E methodology directly places a higher emphasis on each class's demand contribution relative to volume. Thus, the A&E method, itself, suffers from a bias that favors relatively higher load factor classes like industrial customers at lower load factor classes' expense (such as residential and small commercial customers).

Q. WHY ARE THESE DOUBLE COUNTING CLAIMS INACCURATE?

A. The double counting claim conflates the concepts of annual throughput and peak demand and the roles each of these play in utility system planning. These arguments are also faulty since they effectively presume that utilities design systems to first meet the needs of customers without significant weather considerations and only later develop resources dedicated to customers that have these seasonal peaking requirements. In reality, demand and annual throughput reflect

[40] R.L. Conkling (2011), Energy Pricing: Economics and Principles, pages 96-97; *citing* Re: Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Federal Power Commission Docket No. 11. F.P.C. 43.
[41] Rebuttal Testimony of John D. Taylor at 13:2-6.
[42] Rebuttal Testimony of John D. Taylor at 13:6-8.

separate and differing utility planning parameters and system planners develop resources to meet all of their load requirements, not separately to meet individual or class-specific requirement.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS LOGICAL ERROR?

A. Yes. Consider a firm service customer class with a 100 percent load factor. The A&E methodology will assign the "excess demand" component of the calculation a zero value, since peak demand requirements equal average demand requirements, effectively considering the class as having no peak demand requirements. However, customer classes with a 100 percent load factor utilize system resources during all hours, both peak and off-peak. Thus, the A&E methodology effectively views the utility role in system planning as first serving the needs of its high load factor customers and then serving the needs of weather-sensitive customers, placing all costs associated with excess capacity built into its system on these weather-sensitive customers.

Q. DOES YOUR PROPOSED COST ALLOCATION APPROACH RECOGNIZE THE NEED FOR THE UTILITY TO SERVE BOTH PEAK AND OFF-PEAK SYSTEM DEMANDS?

A. Yes. By weighting the average component by the Company's test year system load factor, and the peak demand component by the inverse (i.e., 1 minus) of the system load factor, my proposed P&A allocation recognizes the weight peak day demand requirements place on the Company's planning relative to annual throughput. Simply put, my proposed cost allocation recognizes that roughly 58 percent of the Company's peak day requirements are indistinguishable from its average demand requirements.

V. RATE DESIGN

Q. PLEASE SUMMARIZE THE COMPANY WITNESS TAYLOR'S POSITION REGARDING YOUR RECOMMENDATION THAT THE COMMISSION REJECT THE

COMPANY'S PROPOSED INCREASE IN ITS RESIDENTIAL BASIC SERVICE CHARGE.

A. The Company continues to advocate for its proposed increase in fixed customer charges, including the proposed 41.5 percent increase in the monthly residential customer charge from $16.25 to $23.00.[43] The Company argues that the proposed monthly residential customer charge is significantly below its finding of customer-related costs for residential customers of $54.03 per month.[44] Likewise, the Company downplays energy conservation and efficiency goals by simply pointing out that rate design must balance multiple regulatory objectives.[45]

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S ARGUMENT.

A. In my direct testimony, I independently analyzed Company expenses directly related to providing service to customers and found that customer-related costs to provide service to residential customers on the Company's system of approximately $38.66 per customer per month.[46] Importantly, this means that the Company's current monthly customer charge of $16.25 per month recovers nearly 42 percent of monthly customer-related costs.[47]

Q. WHAT IS THE REASON FOR THE DIFFERENCE IN YOUR ANALYSIS OF CUSTOMER-RELATED COSTS VERSUS THE COMPANY'S?

A. The Company's analysis of customer-related costs includes costs that are not directly related to customer-related expenses, such as overhead costs related to general plant investments and administrative and general ("A&G") expenses.

[43] Rebuttal Testimony of John D. Taylor at 17:18-22.
[44] Rebuttal Testimony of John D. Taylor at 19:7-11.
[45] Rebuttal Testimony of John D. Taylor at 20:6-8.
[46] *See*, Direct Testimony of Michael W. Deupree at Exhibit MWD-8.
[47] Direct Testimony of Michael W. Deupree at 62:12-15.

Q. DOES THE COMPANY DISPUTE YOUR STATEMENT THAT LOW-INCOME CUSTOMERS ARE TYPICALLY LOW-USE CUSTOMERS?

A. Yes. The Company references its analysis finding that customers with "confirmed low-income indicators" had higher average use when compared to the average of the Company's non-low-income customers.[48] Therefore, the Company claims that higher customer charges necessitate lower variable charges which creates social equity concerns by shifting revenue responsibilities from higher income customers to lower income customers.[49]

Q. DO YOU AGREE WITH THE COMPANY'S DESCRIPTION OF CUSTOMER USE BY INCOME GROUP?

A. No. The Company's analysis is based on a very broad description of low-income. The Company's definition of "confirmed low-income indicators," includes those enrolled in the Customer Assistance Program ("CAP"), Low Income Usage Reduction Program ("LIURP"), received an Operation Share grant, or a Low Income Home Energy Assistance Program ("LIHEAP") grant within the prior 12 months.[50] Importantly, this may include households with annual incomes equal to as much as 250 percent of the Federal Poverty Income Guidelines ("FPIG").[51] In 2026, 250 percent of the FPIG in Pennsylvania would have an annual income of $68,300 for a family of three.[52] Importantly, the Census Bureau in 2024 estimated that the median household income in Pennsylvania in 2024 was $77,971,[53] or approximately 14 percent greater than the Company's definition of "confirmed low-income indicators" for a family of three. Indeed, as shown by Witness Colton, low-income households (defined as households in the bottom 20

[48] Rebuttal Testimony of John D. Taylor at 23:5-10; and Direct Testimony of John D. Taylor at 28:14 to 29:2.
[49] Direct Testimony of John D. Taylor at 29:3-11.
[50] Direct Testimony of John D. Taylor at 28, f.n. 10.
[51] Direct Testimony of John D. Taylor at 28, f.n. 10.
[52] Federal Poverty Income Guidelines, Commonwealth of Pennsylvania, Department of Human Services.
[53] QuickFacts – Pennsylvania, United States Census Bureau.

percent by household income) in approximately 63 percent of zip codes the Company operates in have annual household incomes of less than $25,500.[54]

Q. DID THE COMPANY RESPOND TO YOUR ALTERNATIVE RECOMMENDATION IF THE COMMISSION DECIDES AN INCREASE IN RESIDENTIAL BASIC SERVICE CHARGES IS WARRANTED?

A. Yes. If the Commission decides that an increase in residential basic service charges is warranted, I argued that this increase should be capped at the overall allowed increase in residential rates, including scalebacks for any adjustment in the overall allowed increase in residential rates. The Company disagrees with this alternative recommendation, arguing that basic service charges should be based on the cost to serve, and that scaling back the customer charge merely to match a reduced revenue requirement would disconnect the rate design from cost causation.[55]

Q. DO YOU AGREE WITH THE COMPANY?

A. No. The Commission should recognize that increasing the customer charge disproportionately to volumetric rates increases the burden on low use customers which are typically low-income customers, as well as decreasing the incentive for customers to conserve energy. Partially for this reason, I disagree with the Company's proposed increase in the residential basic service charge. However, if the Commission believes an increase in the residential basic service charge is warranted, it should maintain the existing balance between volumetric and fixed customer charges to not increase the burden on vulnerable communities.

[54] *See* Direct Testimony of Roger D. Colton at 12, Table 3.
[55] Rebuttal Testimony of John D. Taylor, at 29:6-12.

VI. CONCLUSIONS AND RECOMMENDATIONS

A. Having reviewed the rebuttal testimony filed by the Company in this proceeding, I continue to recommend the Commission:

- Require some level of shared burden in light of recent macroeconomic challenges, balancing consumer affordability concerns with the financial interests of the Company.
- The Commission should affirmatively discontinue the current WNA. The mechanism has failed to produce balanced outcomes for ratepayers, functioning as an asymmetric surcharge on customers' bills for the three full years the mechanism has been in operation. If, in the alternative, the Commission decides to continue the WNA, I recommend the Commission increase the deadband from three percent to five percent, and eliminate the month of October from the WNA period.
- Reject the Company's proposed A&E cost allocation method to allocate costs associated with distribution mains within the Company's ACOSS. In the alternative I recommend the Commission approve an alternative allocation method of distribution mains that incorporates a P&A cost allocation method using weights based on the Company's test year system load factor.
- Adopt a more reasonable revenue apportionment method based on my alternative ACOSS results that also limits the rate increase compared to the Company's proposed revenue allocation method. Specifically, I recommend the Commission limit the rate increase to any single customer class to no more than 1.15 times the system average increase.
- Reject the Company's proposed increase in residential and commercial customer charges. The Company's proposed increase in customer charges comes in the immediate aftermath of an 8.3 percent increase in these same charges in the Company's prior rate case, Docket No. 2024-3052716. Furthermore, an analysis of customer-related costs finds that residential rate classes are currently recovering a significant portion of customer-related costs through monthly customer charges. If the Commission decides in the alternative that an increase in monthly customer charges is warranted, these increases should be limited to the percentage increase in class revenue requirement. This would furthermore be subject to scalebacks to reflect changes in allocated class revenue increases pursuant to Commission Orders.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

Table of Exhibits

Title	Exhibit
Open Letter from Governor Josh Shapiro dated April 29, 2026	Exhibit MWD-9
PECO Communication dated April 16, 2026	Exhibit MWD-10

Open Letter from Governor Josh Shapiro dated April 29, 2026

GOVERNOR JOSH SHAPIRO

April 29, 2026

Dear Utility Leaders:

As you are no doubt aware, many of your customers across the Commonwealth are experiencing markedly higher utility costs. Rising utility bills have themselves become drivers of inflation. While there are many factors affecting those increases, several core causes are directly within your control and result from your policy and fiscal decisions, including the excessive rate requests several utilities have sought in recent years. Last year alone, 13 Pennsylvania utilities requested $975 million in higher rates after those very same utilities had earned a total of $1.4 billion in profits in 2024.

We have reached a tipping point, and this is a moment to put your customers first and change the behaviors causing rate increases. As I've expressed publicly and privately, I believe the 20th century utility model is broken—we can no longer simply prioritize corporate profitability to drive infrastructure development. Rather, we must be laser focused on delivering on the actual needs of our communities. As I stated clearly in my Budget Address in February, Pennsylvania consumers should not be asked to pay a single dollar more than is needed to support a safe and reliable utility system.

Change is needed, and my Administration stands ready to support each Pennsylvania utility in raising the capital you need to invest in your service territories and workers, both in modernizing with cost-effective new technologies and maximizing the existing infrastructure that you have developed over time. However, as we work together to implement this new approach, you must seek to procure that capital in more affordable ways, conscious of the utility burdens facing many consumers across our Commonwealth.

Open Letter from Governor Josh Shapiro dated April 29, 2026

I write today to lay out three commonsense practices to ensure the needs of Pennsylvanians come first. My Administration will use these three practices as a benchmark to evaluate rate case proposals going forward. Let me be clear: my Administration and I will vocally and forcefully oppose rate case requests from utilities that fail to adhere to these three commonsense practices.

First, utilities should seek to raise the most cost-effective forms of capital. Best practices now require you to protect consumers by disfavoring expensive equity when lower-cost debt is available. Given the low risk profile of monopolistic utilities, which maintain a captive rate base able to repay obligations over time, consumers should not be expected to bolster corporate profits through over reliance on costly equity. This means debt should normally represent a clear majority of a utility's proposed ratemaking capital structure, as it does in many other lower-risk industries. As one measure of this approach, any equity share proposed in a rate case in excess of the amount of equity employed by the utility's parent holding company will require extraordinary justification to receive my Administration's support.

For utilities looking to find low-cost sources of capital, my Administration encourages you to apply to the Department of Energy, which is currently offering loan terms as favorable as the 10-year U.S. Treasury yield plus 35 basis points. By comparison, the average Pennsylvania utility requested a return on equity a staggering 682 basis points above the 10-year U.S. Treasury yield last year. Before raising such expensive equity, you should take advantage of more affordable sources of capital, like these loans, that many of your fellow utilities across the country are pursuing. My Administration stands ready to facilitate an introduction to loan officers at the Department of Energy upon your request.

Second, whenever new revenue is sought, a utility must explain in plain, clear language why its proposed investments are necessary, using transparent data to identify a specific reliability or safety concern that will be addressed, or demonstrating with a thorough cost/benefit analysis that the investment will produce significant savings or reliability benefits for consumers. This means showing the value customers will receive in terms of discrete improvements producing tangible outcomes that are timebound, verifiable, and logically linked to the need for additional capital. Creating real value for customers also means maximizing existing grid resources in ways that control costs and defer the need for future upgrades. You must also describe explicitly what amount of your

requested rate increase will be remitted to shareholders through corporate dividends or other means, as compared to what would be used to directly advance the needs of your customers.

Third, you must provide transparent, justifiable equity returns. Pennsylvania has a long, proud tradition of trusting free markets to deliver fair, transparent pricing. In fact, this year marks the 30th anniversary of Act 138, which introduced competition into our utility sector for the first time. That bipartisan law embodies Pennsylvania's deep-seated belief that free-market competition—when properly implemented and overseen—is the best tool for delivering customers the fair value they deserve. Today, we use markets to price our wholesale power and rely on principles of competition to fairly and impartially award public contracts. Yet less accurate administrative determinations—essentially amounting to educated guesses—still govern how much utilities earn on their equity investment. And all too often the outcome of this administrative process is shrouded in "black box" settlements, that do not provide the public with transparency about costs they will have to pay. These vestiges of the past need to evolve to ensure that utilities are not seeking excessive profits but only the opportunity to earn the fair rate of return to which they are entitled.

To accomplish this, utilities can prove their need for a requested return on equity by providing a benchmark (representing at least 10% of the incremental requested equity) that is transparently derived through a public process with competitive bidding by multiple participants to establish a fair market cost of that equity. This sample offers the energy consumer and Public Utility Commission real-world evidence of the proper authorized return on equity, an amount that will allow the utility to earn reasonable equity returns under efficient operations. If a utility declines to justify its requested return on equity through a competitive, transparent process, it creates a presumption in the view of my Administration that the requested rate is higher than would have been derived from such a competitive process. Absent extraordinary and unforeseen circumstances, a utility can overcome that presumption by requesting a return on equity that does not exceed the rate of the current 10-year U.S. Treasury yield plus the five-year median of the equity risk premium as published in the Federal Reserve's Financial Stability Reports. In simple terms, this allows the filing utility to earn the same expected return as the stock market as a whole, according to Federal Reserve estimates, comfortably exceeding typical Public Utility Commission calculations of risk for the utility sector.

Open Letter from Governor Josh Shapiro dated April 29, 2026

This provides an outcome that is fair for your utility and your customers even without an auction or other market-based price discovery mechanism.

This letter is an effort to be up front with you about my Administration's approach to rate requests going forward. In directly laying out these practices, I am making clear my expectations. I stand ready to collaborate with you, the Public Utility Commission, and other stakeholders in advancing thoughtful rate requests that put Pennsylvania families and businesses first and control costs after years of unacceptably high rate increases. Should you wish to have my Administration's support for any future rate requests, you must submit a description of your compliance with these practices to my Special Counsel for Energy Affordability alongside your rate case filings.

I appreciate your compliance with these practices and look forward to working together to control costs for ratepayers and build out the needed infrastructure for our Commonwealth.

Sincerely,

Governor Josh Shapiro

Cc: Honorable Stephen M. DeFrank, Chair, Pennsylvania Public Utility Commission
Honorable Kimberly M. Barrow, Vice Chair, Pennsylvania Public Utility Commission
Honorable Kathryn L. Zerfuss, Commissioner, Pennsylvania Public Utility Commission
Honorable John F. Coleman, Commissioner, Pennsylvania Public Utility Commission
Honorable Ralph V. Yanora, Commissioner, Pennsylvania Public Utility Commission
Mark Szybist, Special Counsel for Energy Affordability, Office of General Counsel

PECO Communication dated April 16, 2026

FOR IMMEDIATE RELEASE

PECO Withdraws Electric and Natural Gas Regulatory Rate Review Filings to Prioritize Customer Affordability

PHILADELPHIA | April 16, 2026

PECO Communications | PECO.Media@exeloncorp.com

PHILADELPHIA, PA (April 16, 2026) – Citing significant financial pressures facing households and businesses across southeastern Pennsylvania, PECO announced it is withdrawing its previously filed electric and natural gas distribution rate review filings with the Pennsylvania Public Utility Commission (PUC). The decision reflects a deliberate effort to prioritize customer affordability while continuing to deliver safe and reliable service.

Customers and communities across the region are facing sustained financial strain driven by rising costs for housing, food, healthcare, transportation, energy supply costs, and other everyday essentials. Against that broader economic backdrop, and taking into consideration conversations with Governor Josh Shapiro, as well as input from customers, community partners, and stakeholders, PECO reassessed the cumulative impact of the proposed rate changes on customers and determined now is not the right time to move forward.

"Keeping bills as low as possible through efforts like PECO's $12.5 million Customer Relief Fund to help low- and middle-income customers struggling with high energy costs is a top priority," said David Vahos, PECO president and CEO. "While our filing with the PUC would have provided needed improvements in safe and reliable energy delivery, we recognize that Pennsylvanians are struggling with basic necessities like gas, food, and energy and have decided to withdraw our proposal. We look forward to working with stakeholders across the region to find long-term solutions to high energy costs and to make needed investments at another time."

The withdrawn filings were intended to support near- and long-term electric and natural gas system modernization. However, it was determined that advancing those longer-term investments at this time would place additional strain on customers who are already managing significantly higher energy supply costs and broader cost-of-living challenges.

This decision reflects a careful balance between customer affordability and the company's responsibility to deliver high-quality service for the long term. PECO is committed to putting customers and communities first and acting responsibly when making major decisions. The company will continue near-term investments focused on system safety, essential maintenance, operational integrity, and reliability standards customers depend on every day. Customers can expect continued strong reliability performance as PECO continues to manage costs responsibly.

At the same time, PECO will continue evaluating longer-term grid modernization investments that support economic growth, job creation, and evolving energy needs across southeastern Pennsylvania. Withdrawing the filings gives the company the flexibility to better assess the timing, scope, and sequencing of those investments in the context of affordability and system priorities.

The company will also refocus on efforts to enact changes that will help to drive down energy supply prices – costs that the company does not control or profit from – to ensure adequate energy supply is available to meet rising demand. This continued "**all-of-the-above**" strategy is essential to continued affordability and reliability.

Safety remains non-negotiable. This strategic pivot does not change how PECO operates or protects its electric and natural gas systems, its employees, or the communities it serves.

PECO remains committed to a strong, transparent partnership with the PUC and will continue engaging regulators and stakeholders as it evaluates the appropriate path forward.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division
:

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: */s/ Michael Deupree*
Michael Deupree

Address: Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808

OCA St. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2025-3059523**
	)	
UGI Utilities, Inc. – Gas Division	)	
	)	

PUBLIC, REDACTED DIRECT TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 13, 2026

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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Schedules Accompanying Direct Testimony:

- Appendix A – Resume of Jennifer L. Rogers
- Schedules JLR-1 Through JLR-23

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer L. Rogers. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Principal and Vice President at Exeter Associates, Inc. ("Exeter"). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Arts degree in Economics from Northeastern University. I also have a Bachelor of Arts degree in Economics with a minor in Environmental Studies from St. Mary's College of Maryland. I attended the 42nd Eastern National Association of Regulatory Utility Commissioners ("NARUC") Utility Rate School. I have also completed the Institute of Public Utilities Accounting and Ratemaking Course and the Advanced Course: Regulatory Accounting and Auditing, as well as EUCI's Electric Cost-of-Service Course.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed with Exeter since 2009, initially as a Research Assistant before being promoted to Economist, then Senior Economist, and then Lead Economist. I am now a Principal and Vice President for the firm. At Exeter, I review utility rate filings and provide analysis of revenue requirement issues. I also evaluate and forecast power supply requirements, costs, and renewable energy needs; provide bill and rate analysis; and review energy use, scheduling, and scheduling deviation data for clients. In addition, I conduct utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony before the Pennsylvania Public Utility Commission; the Philadelphia Water, Sewer, and Storm Water Rate Board; the Maryland Public Service Commission; the State of Rhode Island Public Utilities Commission; the Public Utility Commission of Texas; the Maine Public Utilities Commission; the State Corporation Commission of the State of Kansas; and the Arizona Corporation Commission. My resume is attached as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter has been retained by the OCA to assist in the evaluation of the application of the UGI Utilities, Inc. – Gas Division ("UGI" or "Company") to increase base rates for gas service. My direct testimony presents my findings with respect to UGI's revenue requirements and its proposed rate increases. I calculate UGI's rate base, pro forma operating income under present rates, and overall revenue deficiency based upon my recommended adjustments

II. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY UGI IN ITS FILING.

A. On January 28, 2026, UGI filed an application with the Pennsylvania Public Utility Commission ("Commission") to increase its base rates for gas service. UGI is requesting an overall rate increase of $99.368 million. The Company's proposed rate

increase is based upon the fully projected future test year ("FPFTY") ending September 30, 2027.[1] The Company's requested rate increase reflects an overall rate of return ("ROR") of 8.20%.[2]

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. I have been advised by OCA counsel that due to substantial consumer affordability concerns, the OCA will be arguing in its legal briefs that the Commission should keep UGI's rates at their current levels at this time. My testimony will address the alternative OCA position if any rate increase is ultimately ordered by the Commission.

As discussed in OCA witness David Garrett's testimony, OCA is presenting a primary ROE and debt ratio recommendation, and an alternative recommendation in the event the Commission adopts UGI's capital structure. As shown on Schedule JLR-1 (CONFIDENTIAL), based on the OCA's primary recommendation of 8.8% authorized ROE and 51% debt ratio, I have determined that UGI's proposed revenue increase should be reduced to reflect a decrease of $15.8 million for the FPFTY. This is $115.2 million less than the Company's requested increase of $99.368 million. This is the amount by which revenues exceed those required to generate an overall ROR on rate base of 6.95%, which is per the primary recommendation detailed in the Direct Testimony of OCA witness David Garrett, after accounting for the OCA's adjustments to UGI's claimed rate base and operating income.

However, if the Commission adopts UGI's capital structure, then utilizing the OCA's alternative recommendation of an 8.5% ROE, I have determined that UGI's proposed revenue increase should be reduced to reflect a decrease of $9.5 million for the FPFTY, as shown on Schedule JLR-18 (CONFIDENTIAL).

[1] Direct Testimony of Hans G. Bell, 5:22 through 6:1.
[2] Direct Testimony of Tracy A. Hazenstab, 6:13-14.

Q. WHAT PERIOD HAVE YOU USED IN MAKING YOUR DETERMINATION OF UGI'S REVENUE REQUIREMENT?

A. I have determined my revenue requirement recommendations based on the FPFTY ending September 30, 2027. This is the same period used by the Company to develop its revenue requirement.

Q. IN CONNECTION WITH THIS PROCEEDING, WHAT DOCUMENTS HAVE YOU EXAMINED AND REVIEWED IN MAKING YOUR RECOMMENDATIONS?

A. I have reviewed UGI's rate filing, testimony, and exhibits. I also reviewed the Company's responses to data requests propounded by the OCA, the Bureau of Investigation and Enforcement ("I&E"), RESA, and CAUSE-PA.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules JLR-1 through JLR-23. As discussed earlier, OCA witness David Garrett's testimony is presenting a primary ROE and debt ratio recommendation, and an alternative recommendation in the event the Commission adopts UGI's capital structure (referred to as the "alternative recommendation" below). Schedules JLR-1 through JLR-17 reflect the primary recommendation, while Schedules JLR-18 through JLR-23 reflect the alternative recommendation.

Schedule JLR-1 (CONFIDENTIAL) provides a summary of the calculation of the increase in revenues after reflecting the adjustments proposed by the OCA. Schedule JLR-2 provides my recommended rate base. Schedule JLR-3 (CONFIDENTIAL) presents the summary of the cost of service (revenues and operating expenses) adjustments. My adjustments to UGI's claimed revenues and operating expenses are presented on Schedules JLR-4 through JLR-17. Schedule JLR-18 (CONFIDENTIAL)

is the alternative recommendation version of Schedule JLR-1 (CONFIDENTIAL). Schedule JLR-19 is the alternative recommendation version of Schedule JLR-2. Schedule JLR-20 (CONFIDENTIAL) is the alternative recommendation version of Schedule JLR-3 (CONFIDENTIAL). Schedule JLR-21 is the alternative recommendation version of Schedule JLR-4. Schedule JLR-22 is the alternative recommendation version of Schedule JLR-16. Schedule JLR-23 is the alternative recommendation version of Schedule JLR-17.

Q. PLEASE EXPLAIN HOW THE REMAINING SECTIONS OF YOUR TESTIMONY ARE ORGANIZED.

A. The discussion of my findings and recommendations is presented in the following section, Section III. In that section, I address the revenue requirement issues (rate base and operating income) that I identified in this proceeding. Where I recommend an adjustment to a particular component of the rate base, revenues, or expenses, I document and explain the reason for the adjustment and note the related schedule in which the detailed calculations can be found. An outline of the topics within the section is set forth in the Table of Contents of my testimony.

III. ADJUSTMENTS

A. Allowance for Cash Working Capital

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the utility earns a return on it. Negative cash working capital represents funds supplied by ratepayers

that should be recognized as a rate base offset to reflect funds advanced for operations by ratepayers.

Q. HOW DOES THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance has been determined based upon the results of a lead/lag study. A lead/lag study is an in-depth analysis that measures the difference between the lapse of time when a company receives revenue for the provision of service and the lapse of time when a company pays for the costs of providing service. This difference is expressed as a number of days and is used to calculate the level of investor-supplied funds advanced for operations, or the funds advanced by customers for operations.

Q. WHAT CHANGES HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. I have incorporated the adjustments to operations and maintenance ("O&M") expenses and taxes that I am recommending below, as these serve as the basis upon which the cash working capital is calculated. I have also flowed through the OCA's recommended long-term debt ratio and cost of long-term debt into the calculation of the interest payments portion of the cash working capital requirement. I have therefore made an adjustment to cash working capital to reduce rate base by $3.76 million, as shown on Schedule JLR-4.[3]

B. Depreciation Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

[3] Schedule JLR-21 is the alternative recommendation version of Schedule JLR-4, in which case the adjustment to cash working capital would reduce rate base by $2.38 million.

A. I have applied the depreciation recommendations per the direct testimony of OCA witness James Garren to the calculation of depreciation expenses. As shown on Schedule JLR-5, this decreases depreciation expenses by $21.8 million. I have also made the corresponding adjustment to accumulated depreciation, increasing rate base by $21.8 million, also shown on Schedule JLR-5. If the Company is able to calculate the related ADIT adjustment based on the difference between book depreciation for the FPFTY plant and the tax depreciation, and provide this in Rebuttal, I may update my recommendation in Surrebuttal to incorporate this flow through adjustment as well.

C. Rate Case Expense

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO RATE CASE EXPENSE?

A. The Company presented a total rate case expense of $1.76 million, normalized over one year, resulting in an annual recovery of $1.76 million for the FPFTY rate case expense.[4] I recommend that the normalization period be increased to two years because the recovery of rate case expense should be spread over the period that benefits from incurring the rate case expense. The benefit period is typically measured as the period between rate cases. As explained in *A Guide to Utility Ratemaking*, "The Commission's practice is to recognize all prudently-incurred rate case expense and set a normalization period based upon historic filing frequency."[5] The Company's last three filings prior to the current 2026 filing were in 2025, 2022, and 2020.[6] The average length of time between filings is two years, and therefore is the basis of my recommendation. This recommendation decreases O&M expenses by $880,000 as shown on Schedule JLR-6.

[4] Company Exhibit A, Fully Projected, Schedule D-10.

[5] James H. Cawley and Norman J. Kennard, *A Guide to Utility Ratemaking* (2018 Edition), Pennsylvania Public Utility Commission, 1983, p. 112.

[6] Company response to OCA-14-8.

D. Incentive Compensation Expense

Q. PLEASE DESCRIBE UGI'S INCENTIVE COMPENSATION PLANS.

A. The Company offers several incentive plans, including UGI Utilities Inc.'s Management Incentive Plan, Executive and Non-Executive Annual Bonus Plans, Sales Commission Plan, Discretionary Bonus Policy, Inside Sales Group Incentive Plan, Customer Care Scorecard and Incentive Plan, and Equity Compensation Plans.[7]

Q. DO FINANCIAL PERFORMANCE MEASURES REPRESENT A COMPONENT OF UGI'S INCENTIVE COMPENSATION STRUCTURE?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. IS IT APPROPRIATE FOR RATEPAYERS TO BEAR THE COST OF INCENTIVE COMPENSATION TIED TO FINANCIAL METRICS?

A. No, it is not. A fundamental principle of ratemaking is that costs should be assigned to those who benefit from them. In the case of incentive compensation tied to financial

[7] UGI Company Filing Book II, SDR-RR-27, and Attachments SDR-RR-27.1 through SDR-RR-27.7.

[redacted]

performance, such as earnings per share, stock price, and total shareholder return, the primary beneficiaries are shareholders. These incentives are specifically designed to increase shareholder value, which is realized through higher stock prices, increased dividends, and enhanced company valuation. The equity compensation plans detail this explicitly, with the Incentive Award Plan stating:

> "The purpose of the Plan is to provide designated Employees, Consultants and Non-Employee Directors with the opportunity to receive Awards hereunder in order to encourage such individuals to contribute materially to the growth of the Company, thereby benefiting the Company's shareholders, and to more closely align the economic interests of such individuals with those of the Company's shareholders."[10]

Ratepayers, by contrast, do not receive these benefits. They do not participate in equity ownership and do not share in financial market gains. Therefore, it is not appropriate to require ratepayers to fund compensation programs that are structured to benefit shareholders.

Q. WHY IS IT IMPORTANT TO CONSIDER THE DIFFERENCE BETWEEN SHAREHOLDER AND RATEPAYER INTERESTS?

A. The interests of shareholders and ratepayers are not always aligned and can at times be directly opposed. Shareholders benefit from increased earnings and returns, while ratepayers benefit from cost control and stable or lower rates. Incentive structures that emphasize financial performance can encourage management to prioritize profitability over affordability or operational efficiency.

Q. ARE YOU RECOMMENDING THAT ALL INCENTIVE COMPENSATION BE EXCLUDED FROM RATES?

A. No, I am not. It is important to distinguish between incentive compensation tied to operational performance and that tied to financial performance. Incentives related to

[10] Company response to SDR-RR-27, Attachment SDR-RR-27.6.

safety, reliability, or customer satisfaction may provide direct benefits to customers and can be appropriate for recovery in rates. However, incentives tied to financial outcomes primarily serve to align management with shareholder interests rather than customer interests. My recommendation is limited to excluding the portion of incentive compensation that is tied to financial metrics, not those tied to operational performance.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO INCENTIVE COMPENSATION.

A. For the reasons explained above, I recommend disallowing incentive compensation expenses related to financial metrics. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

E. Employee Activity Expense

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EMPLOYEE ACTIVITY EXPENSE.

A. The Company has proposed including costs totaling $583,036 in the cost of service related to employee activities. These expenses are related to items such as picnics, parties, and safety awards.[11]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE EMPLOYEE ACTIVITY EXPENSES IN THE COST OF SERVICE?

A. No, I do not. This expense item relates to costs that do not aid in the provision of service but rather are for items such as a picnic and awards. Ratepayers should not be responsible for expenses which do not relate to the provision of safe and reliable utility service. I am therefore recommending the Commission disallow this expense from

[11] UGI Company Filing Book II, SDR-RR-30(e).

inclusion in the cost of service. This adjustment reduces expenses by $583,036, as presented in Schedule JLR-8.

F. Vacancy Reserve

Q. HAS THE COMPANY INCORPORATED A VACANCY RATE INTO CALCULATIONS OF WAGES AND SALARIES FOR THE FPFTY?

A. Yes, the Company incorporated a vacancy rate within its FPFTY claim. The Company applied a vacancy rate adjustment of 4.7 percent to its labor expense.[12]

Q. DO YOU AGREE WITH THE COMPANY'S VACANCY RATE ADJUSTMENT?

A. No, I do not. In examining historical data, it is clear this proposed vacancy rate is abnormally low compared to the actual level of vacancies experienced over the past three years, as shown in the table below.

Total Vacancy Percentage (%)[1]			
	2022-2023	2023-2024	2024-2025
October	8.3	5.7	4.2
November	8.2	6.2	4.5
December	7.9	6.4	4.8
January	7.5	6.6	5.4
February	7.2	6.8	5.7
March	6.3	7.4	5.7
April	6.1	8.0	5.6
May	3.8	8.6	4.6
June	3.1	9.6	4.4
July	2.9	9.6	4.3
August	3.0	10.2	4.4
September	3.8	10.6	3.9

[1] Company response to I&E-RE-24, Attachment I&E-RE-24(C).

The average vacancy rate across the three-year period is 6.15 percent. Utilizing an abnormally low vacancy rate risks overcollection from ratepayers.

[12] Company response to I&E-RE-25.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE VACANCY RATE.

A. Vacancy rates are a variable element, that may increase or decrease month to month. I therefore believe it is necessary to normalize the vacancy rate as the average value of the last three years to reflect a normalized year. The Company has had an average vacancy rate of 6.15 percent over the past three years, which is the basis of my recommendation. I have applied this value to the salaries value, after adjusting the salaries downward to reflect the incentive compensation adjustment previously recommended in the "Incentive Compensation Expense" section of my testimony to determine the OCA recommended adjustment to salaries for vacancy rate. This adjustment reduces O&M expenses by $1.1 million as shown on Schedule JLR-9 (CONFIDENTIAL). The vacancy rate adjustment also flows through to result in a reduction in payroll taxes of $87,663 as shown on Schedule JLR-10, and employees benefits expense by $265,685 as shown on Schedule JLR-11.

G. Advertising Expense – Conservation of Energy

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED ADVERTISING EXPENSE RELATED TO CONSERVATION OF ENERGY.

A. The Company has stated that it expects to have $272,515 in expenses related to Conservation of Energy in the FPFTY.[13] The Company has indicated that the FPFTY includes costs associated with a marketing campaign promoting the use of natural gas as a more energy efficient and affordable alternative to other competitive fuels.[14]

[13] UGI Company Filing Book I, Section 53.53-III-A-25.

[14] Company response to I&E-RE-43.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADVERTISING EXPENSE FOR CONSERVATION OF ENERGY?

A. No, I do not. The Company is showing a significant increase in this expense item over recent years, increasing from $73,040 in FY 2024 to $272,515 in FY 2027.[15] The Company explains in response to discovery that the increase is due to a UGI fuel conversion marketing campaign in FY 2025, which was not run in FY 2023 and 2024.[16] These costs represent an intermittent advertising campaign, rather than a normal, recurring annual expense. Accordingly, it is inappropriate to include these costs in rates as a recurring annual expense, as doing so would result in over-collection from customers in years when such expenses are not incurred.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE PROPOSED ADVERTISING EXPENSE FOR CONSERVATION OF ENERGY.

A. I am recommending isolating the non-recurring portion of the expense and normalizing it for recovery over two years, consistent with the normalization period I have recommended in the "Rate Case Expense" portion of my direct testimony. As FY 2024 did not incur this abnormal periodic expense and FY 2025 did, I have used the difference between the FY 2024 value and FY 2025 value to calculate the non-recurring portion of expense, which I normalized over two years to adjust the FPFTY. This adjustment is presented on Schedule JLR-12, and results in a decrease to O&M expenses of $81,187.

[15] Company response to I&E-RE-43, Attachment I&E-RE-43.
[16] Company response to OCA-14-26.

H. Advertising Expense - Other

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED "OTHER ADVERTISING PROGRAMS" EXPENSES.

A. The Company expects to have $380,397 in expenses related to Other Advertising Programs in the FPFTY, of which $191,149 is attributed to community event sponsorships and $189,249 is attributed to stakeholder newsletters.[17]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE EXPENSES RELATED TO COMMUNITY EVENT SPONSORSHIPS IN COST OF SERVICE?

A. No, I do not. Community event sponsorships are largely promotional in nature and do not relate to the provision of safe, reliable, and adequate utility service to ratepayers, and therefore should not be ratepayer responsibility. I am therefore recommending the Commission disallow this expense from inclusion in the cost of service. This adjustment reduces expenses by $191,149, as presented in Schedule JLR-13.

I. PUC Assessment

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED PUC ASSESSMENT EXPENSE.

A. The Company has derived its PUC Assessment expense projection by taking the 2025 invoice amount and multiplying it by a 14.9% increase to reach a projected 2026 invoice amount, and then again to reach a 2027 invoice amount. The Company derived the 14.9% increase as the average percentage increase over 2022 to 2025. This results in an increase in PUC Assessment expenses from the HTY amount of $4.551 million to $6.006 million in the FPFTY. [18]

[17] Company response to I&E-RE-43, Attachment I&E-RE-43.

[18] Company response to I&E-RE-39, Attachment I&E-RE-39(B-C).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED PUC ASSESSMENT EXPENSE?

A. No, I do not. In examining the historical data, it is apparent that the PUC Assessment charge does not consistently grow year over year, with no growth at all between 2024 and 2025.

	2022 Invoice	2023 Invoice	2024 Invoice	2025 Invoice
PUC Assessment[1] ($000)	$3,051	$3,523	$4,550	$4,552

[1] Company response to I&E-RE-39, Attachment I&E-RE-39(B-C)

Applying a linear percentage increase to an expense item that may not increase risks overcollection from customers. I believe it is necessary to normalize the expected PUC Assessment expenses by taking the average of the most recent three years to determine a representative annual cost for ratemaking.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE PUC ASSESSMENT EXPENSE.

A. For the reasons detailed above, I am recommending normalizing the annual expense level using the average of the most recent three years. This adjustment reduces O&M expenses by $1.8 million, as shown on Schedule JLR-14.

J. Residential Collection Expense

Q. PLEASE EXPLAIN YOUR RESIDENTIAL COLLECTION EXPENSE ADJUSTMENT.

A. I have applied the recommendation per the direct testimony of OCA witness Roger Colton, removing 50 percent of the residential collection expenses. In response to discovery, the Company was unable to provide the exact dollar amount of residential collection expenses included in the FPFTY, stating the expense is embedded in a

FERC Account which includes other costs as well.[19] I have therefore utilized the 2025 residential collection expense value as a proxy. As shown on Schedule JLR-15, this adjustment decreases O&M expenses by $3.097 million.

K. Interest Synchronization

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax-deductible interest for ratemaking, I multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown on Schedule JLR-16, this adjustment decreases state income taxes by $909,000 and federal income taxes by $2.4 million.[20]

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[19] Company response to OCA-15-5.
[20] Schedule JLR-22 is the alternative recommendation version of Schedule JLR-16, in which case this adjustment decreases state income taxes by $34,000 and federal income taxes by $89,000.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2025-3059523**
	)	
UGI Utilities, Inc. – Gas Division	)	

PUBLIC SCHEDULES ACCOMPANYING THE DIRECT TESTIMONY OF JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 13, 2026

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

APPENDIX A – Resume of Jennifer L. Rogers

JENNIFER L. ROGERS

Ms. Rogers is a Principal and Vice President at Exeter Associates, Inc., with over fifteen years of experience in the energy industry. At Exeter, Ms. Rogers reviews and analyzes utility rate filings, and presents testimony focusing primarily on revenue requirements determination. She also evaluates and forecasts power supply requirements, costs, and renewable energy needs; provides bill and rate analysis; and reviews energy use, scheduling, and scheduling deviation data for clients. In addition, Ms. Rogers conducts utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Education

B.A. (Economics) – Saint Mary's College of Maryland, 2007

M.A. (Economics) – Northeastern University, Boston, MA, 2009

Previous Employment

2009-Current Exeter Associates, Inc.
Columbia, MD

- Principal and Vice President 2025-Current
- Lead Economist 2023-2024
- Senior Economist 2018-2022
- Economist 2011-2017
- Research Assistant 2009-2010

2007-2008 Economics Research and Teaching Assistant
Northeastern University
Boston, MA

Professional Experience

Ms. Rogers' work at Exeter is primarily related to analysis of revenue requirement issues in utility rate filings, analysis power supply acquisition, bill and rate analysis and forecasting, and utility service assessment. Ms. Rogers provides support to the U.S. Department of Energy's Northern California national laboratories, generating cost simulations and power procurement models to forecast future power supply requirements and costs. In addition, Ms. Rogers reviews and tracks the Laboratories' billing, energy use, scheduling, and scheduling deviation data. Ms. Rogers works with the U.S. Air Force Civil Engineer Center to complete utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of energy usage, supply contracts, and a review of billing practices. Ms. Rogers also assists clients in reviewing utility rate filings, providing analysis on revenue requirement issues. Ms. Rogers' work at Exeter has also included assisting in studies of variable generation forecasting, feed-in tariffs for renewable energy generation, and transmission cost allocation methodologies.

As a Research Assistant at Northeastern University, Ms. Rogers worked in the fields of industrial organization and labor economics, while her studies focused on economic modeling and policy analysis. Ms. Rogers developed surveys to be used in a longitudinal labor economics study, tutored undergraduate economics students, and provided research on a variety of economics-related topics.

Expert Testimony

Before the Arizona Corporation Commission, Docket No. E-01933A-25-0103, Tuscon Electric Power Company, 2026, on behalf of the United States Department of Defense and all other Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the State of Rhode Island Public Utilities Commission, Docket No. 25-30-WW, Veolia Water Rhode Island, Inc., 2026, on behalf of the Division of Public Utilities and Carries. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3052716, UGI Utilities, Inc. – Gas Division, 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2025-3053112, Philadelphia Gas Works, 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Regulatory Commission of Alaska, Docket Nos. U-24-030 and U-24-031, Golden Heart Utilities, Inc. and College Utilities Corporation, 2025, on behalf of the United States Department of Defense and all other Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3052359, Pike County Light & Power Company – Electric Division, 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3052357, Pike County Light & Power Company – Gas Division, 2025, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3050208, Newtown Artesian Water Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9744, Hagerstown Light Department, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9719, Easton Utilities Commission, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. R-2023-3042804 and R-2023-3042805, Community Utilities of Pennsylvania Inc., 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the State Corporation Commission of the State of Kansas; Docket No. 23-EKCE-775-RTS; Evergy Kansas Central, Inc., Evergy Kansas South, Inc. and Evergy Metro, Inc.; 2023; on behalf of the United States Department of Defense and all other Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2023-3040258, Columbia Water Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maine Public Utilities Commission, Docket No. 2023-00065, Maine Water Company – Biddeford & Saco Division, 2023, on behalf of the Maine Office of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Philadelphia Water, Sewer, and Storm Water Rate Board, Fiscal Years 2024-2025 Rate Proceeding, Philadelphia Water Department, 2023, on behalf of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2022-3032764, Leatherstocking Gas Company, LLC., 2022, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Public Utility Commission of Texas, Docket No. 53601, Oncor Electric Delivery Company LLC, 2022, on behalf of the United States Department of Defense and the Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Maryland Public Service Commission, Case No. 9680, Columbia Gas of Maryland, Inc., 2022, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2015-2462723, United Water Pennsylvania, Inc., 2015, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Publications and Consulting Reports

A Survey of Variable Generation Integration Charges, National Renewable Energy Laboratory, NREL Report No. NREL/TP-5500-57583, March 2013 (with Kevin Porter, Sari Fink, and Michael Buckley of Exeter Associates, and with B.-M. Hodge of NREL)

Survey of Variable Generation Forecasting in the West, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54457, April 2012 (with Kevin Porter).

Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54338, March 2012 (with Kevin Porter).

Long-Term Electricity Report for Maryland, prepared for the Maryland Department of Natural Resources Power Plant Research Program Pursuant to Executive Order 01.01.2010.16, December 2011, (with Steven Estomin, Kevin Porter, Christina Mudd, Emma Nicholson, Sari Fink, Michael Buckley, and Krista Ozarowski).

Alternative Energy Resource Market Assessment, National Association of Regulatory Utility Commissioners, A report for the Public Utility Commission of Ohio, September 2011 (with Kevin Porter of Exeter Associates, Inc., Ed Holt & Associates, Inc., and Sustainable Energy Advantage LLC)

Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities: Revised Edition, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-51263, March 2011 (with Kevin Porter).

A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. SR-5500-49880, February 2011 (with Kevin Porter, Sari Fink, and Christina Mudd).

The Relationship between Wind Generation and Balancing-Energy Market Prices in ERCOT: 2007–2009, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-49415, November 2010 (with Kevin Porter and Emma Nicholson).

The Relevance of Generation Interconnection Procedures to Feed-in Tariffs in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-6A20-48987, October 2010 (with Kevin Porter and Sari Fink).

Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48738, July 2010 (with Kevin Porter and Sari Fink).

Examples of Wind Energy Curtailment Practices, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48737, July 2010 (with Kevin Porter and Sari Fink).

Status of Centralized Wind Power Forecasting in North America, National Renewable Energy Laboratory, NREL/SR-550-47853, April 2010 (with Kevin Porter).

"Bi-Monthly Transmission Updates," of the National Wind Coordinating Collaborative, Prepared for National Renewable Energy Lab, August 2009 - June 2010 (with Kevin Porter).

"Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources, Maryland Power Plant Research Program, PPRP-CEIR-15," January 2010 (with Steven Estomin, Christina Mudd, and Sari Fink of Exeter Associates, Inc. and contributing authors from Versar, Inc. and Environmental Resources Management).

"Wind Power and Electricity Markets," Compiled for the Utility Wind Interest Group, August 2009 (with Kevin Porter and Sari Fink).

JLR-1

CONFIDENTIAL/REDACTED

UGI Utilities Inc.
Gas Division
Summary of Rate Base
For the Twelve Months Ended September 30, 2027

Line No.	Description	Amount per Company Filing [1/]	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Utility Plant	6,676,559		6,676,559
3	Accumulated Depreciation	(1,736,046)	21,800	(1,714,246)
4	Net Plant in Service	4,940,513	$ 21,800	$ 4,962,313
5				
6	Additions to Net Plant			
7	Working Capital Requirements:			
8	Cash Working Capital	66,523	(3,761)	62,762
9	Materials and Supplies	28,644		28,644
10	Gas Inventory	23,662		23,662
11	Total Additions	118,829	$ (3,761)	$ 115,068
12				
13	Deductions to Net Plant			
14	Customer Deposits	(23,197)		(23,197)
15	Accumulated Deferred Income Taxes	(716,793)		(716,793)
16	Total Deductions	(739,990)	$ -	$ (739,990)
17				
18	Gas Rate Base	4,319,353	$ 18,039	$ 4,337,392

Note:
[1/] Company Exhibit A, Fully Projected, Schedule C-1

UGI Utilities Inc.
Gas Division
Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2027

Line No.	Description	Source	Amount
1	Rate Base per Company Filing	Schedule JLR-2, Page 1	$ 4,319,353
2			
3	OCA Adjustments:		
4			
5	Adjustment to Cash Working Capital	Schedule JLR- 4	(3,761)
6	Adjustment to Accumulated Depreciation	Schedule JLR- 5	21,800
7			
8	Total Ratemaking Adjustments		$ 18,039
9			
10	Adjusted Rate Base per OCA		$ 4,337,392

JLR-3

CONFIDENTIAL/REDACTED

UGI Utilities Inc.
Gas Division
Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Working Capital for O&M Expense Per Company	$ 57,012	1/
2	Interest Payments Per Company	$ (9,459)	1/
3	Tax Payment Lag Calculations Per Company	$ 4,570	1/
4	Prepaid Expenses Per Company	$ 14,400	1/
5	Cash Working Capital Requirements Per Company	$ 66,523	1/
6			
7	Revenue Lag Days	57.46	1/
8	O&M Expense Lag Days	27.55	1/
9	Days to mid-point of interest payments	91.25	1/
10			
11	O&M Expenses		
12	O&M Expenses Per Company	$ 695,601	1/
13	OCA Recommended Adjustments to O&M Expenses	$ (14,699)	2/
14	Revised O&M Expenses	$ 680,903	
15	Operating Expenses Per Day	$ 1,865	1/
16	Net (Lead) Lag Days	29.91	1/
17	Revised Working Capital for O&M	55,800	1/
18			
19	Interest Payments		
20	Measure of Value at September 30, 2026	4,319,352	1/
21	OCA Revised Long-term Debt Ratio	51.00%	3/
22	Embedded Cost of Long-term Debt	5.17%	1/
23	Revised Pro forma Interest Expense	113,888	
24	Daily Amount	312	
25	Interest Payment Lag Days	(33.8)	
26	Revised Interest for Working Capital	(10,544)	
27			
28	Tax Payments		
29	Revised Federal Income Tax	42,983	4/
30	Lead (Lag) Payments Days: First Payment	76.00	1/
31	Lead (Lag) Payments Days: Second Payment	17.00	1/
32	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
33	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
34	Revised Weighted Lead (Lag) Dollars	(1,601,129)	
35	Revised Payment Lead (Lag) Days	(37.25)	
36	Net Payment Lead (Lag) Days	20.21	
37	Revised Working Capital Amount	2,380	
38			
39	Revised State Income Tax	9,566	4/
40	Lead (Lag) Payments Days: First Payment	107.00	1/
41	Lead (Lag) Payments Days: Second Payment	17.00	1/
42	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
43	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
44	Revised Weighted Lead (Lag) Dollars	(282,200)	
45	Revised Payment Lead (Lag) Days	(29.50)	
46	Net Payment Lead (Lag) Days	27.96	
47	Revised Working Capital Amount	733	
48			
49	PA Property Tax Working Capital Amount	(113)	1/
50	PURTA Working Capital Amount	107	1/
51	Revised Tax Payment Working Captial Amount	3,106	
52			
53	Prepayments		
54	Prepaid Expenses Working Captial Amount	14,400	1/
55			
56	Adjustment to Rate Base	(3,761)	

Note:
1/ Company Exhibit A, Fully Projected, Schedule C-4
2/ Schedule JLR-3
3/ Schedule JLR-17
4/ Schedule JLR-1

UGI Utilities Inc.
Gas Division
Adjustment to Depreciation Expense
For the Twelve Months Ended September 30, 2027
(Total $'s)

Line No.	Account No.	Description	ORIGINAL COST 1/	Per Company Accrual Amount 1/	Per Company Rate 1/	OCA Recommendation Accrual Amount 2/	OCA Recommendation Rate 2/	Difference
1								
2		**Production Plant**						
3	305	MANUFACTURED GAS PLANT SITE REMEDIATION	-	-	0.0%	0	0.00%	$ -
4	329	OTHER STRUCTURES	-	-	0.0%	0	0.00%	$ -
5	332	FIELD LINES	-	-	0.0%	0	0.00%	$ -
6	335	DRILLING AND CLEANING EQUIPMENT	-	-	0.0%	0	0.00%	$ -
7								
8		Total Production Plant	-	-	0.0%	-	0.00%	-
9								
10		**Transmission Plant**						
11	365.2	RIGHTS-OF-WAY	868,160	10,902	1.3%	11,329	1.30%	$ 427
12	366	STRUCTURES AND IMPROVEMENTS	162,216	271	0.2%	801	0.49%	$ 530
13	367	MAINS	39,468,181	399,385	1.0%	383,965	0.97%	$ (15,420)
14	369	MEASURING AND REGULATING STATION EQUIPMENT	6,172,834	86,642	1.4%	82,871	1.34%	$ (3,771)
15	370	COMMUNICATION EQUIPMENT	3,505,204	76,632	2.2%	69,544	1.98%	$ (7,088)
16	371	OTHER EQUIPMENT	140,637	787	0.6%	991	0.70%	$ 204
17	371.1	TESTING EQUIPMENT	210,011	4,216	2.0%	7,922	3.77%	$ 3,706
18								
19		Total Transmission Plant	50,527,243	578,835	1.1%	557,423	1.10%	(21,412)
20								
21		**Distribution Plant**						
22	374.2	RIGHTS-OF-WAY	3,374,004	42,665	1.3%	38,909	1.15%	$ (3,756)
23	375	STRUCTURES AND IMPROVEMENTS	7,923,019	144,227	1.8%	73,545	0.93%	$ (70,682)
24	376.1	MAINS - PRIMARILY STEEL	816,343,179	12,366,899	1.5%	9,669,065	1.18%	$ (2,697,834)
25	376.2	MAINS - CAST IRON	664,766	0	0.0%	(0)	0.00%	$ (0)
26	376.3	MAINS - PLASTIC	2,371,718,284	38,991,101	1.6%	34,120,044	1.44%	$ (4,871,057)
27	376.5	MAINS - PRIMARILY WROUGHT IRON	305,201	4,749	1.6%	3,893	1.28%	$ (856)
28	376.7	REG AFUDC	1,322,088	33,052	2.5%	29,356	2.22%	$ (3,696)
29	378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	229,058,181	6,274,505	2.7%	3,750,928	1.64%	$ (2,523,577)
30	379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	81,779,825	2,234,071	2.7%	1,663,771	2.03%	$ (570,300)
31	380	SERVICES	1,937,403,605	51,721,129	2.7%	41,176,455	2.13%	$ (10,544,674)
32	381	METERS	169,884,761	4,671,295	2.7%	4,089,395	2.41%	$ (581,900)
33	381.1	METERS - ERTS	49,518,244	3,179,453	6.4%	3,045,718	6.15%	$ (133,735)
34	382	METER INSTALLATIONS	153,631,673	3,708,944	2.4%	3,062,777	1.99%	$ (646,167)
35	383	HOUSE REGULATORS	10,274,123	206,374	2.0%	187,231	1.82%	$ (19,143)
36	384	HOUSE REGULATOR INSTALLATIONS	17,829,357	318,884	1.8%	296,359	1.66%	$ (22,525)
37	385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	42,670,641	797,604	1.9%	742,234	1.74%	$ (55,370)
38	386	OTHER PROPERTY ON CUSTOMERS PREMISES	68,824	1,414	2.1%	1,279	1.86%	$ (135)
39	386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	1,180,774	25,261	2.1%	22,025	1.87%	$ (3,236)
40	386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0.0%	0	0.00%	$ -
41	387	OTHER EQUIPMENT	5,308,206	87,088	1.6%	93,367	1.76%	$ 6,279
42	387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	2,309	0.2%	58,834	3.95%	$ 56,525
43								
44		Total Distribution Plant	5,901,774,124	124,811,024	2.1%	102,125,184	1.73%	(22,685,840)
45								
46		**General Plant**						
47	390.1	STRUCTURES AND IMPROVEMENTS	183,834,899	7,154,215	3.9%	7,167,957	3.90%	$ 13,742
48	390.3	CNG Stations	7,022,614	501,969	7.1%	501,969	7.15%	$ -
49	391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,884,524	322,668	5.5%	328,671	5.59%	$ 6,003
50	391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	249,370	27,845	11.2%	23,727	9.51%	$ (4,118)
51	391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	13,631,489	2,016,027	14.8%	2,919,208	21.42%	$ 903,181
52	391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	5,397,504	485,445	9.0%	487,469	9.03%	$ 2,024
53	391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	43,977,025	2,914,581	6.6%	2,925,010	6.65%	$ 10,429
54	392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	4,667,253	322,732	6.9%	297,695	6.38%	$ (25,037)
55	392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	61,236,851	6,376,417	10.4%	6,309,830	10.30%	$ (66,587)
56	392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	7,626,640	570,922	7.5%	517,642	6.79%	$ (53,280)
57	392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	11,059,662	844,799	7.6%	755,894	6.83%	$ (88,905)
58	392.5	TRANSPORTATION EQUIPMENT - TRAILERS	2,944,491	172,826	5.9%	162,009	5.50%	$ (10,817)
59	393	STORES EQUIPMENT	15,838	792	5.0%	791	4.99%	$ (1)
60	394	TOOLS, SHOP AND GARAGE EQUIPMENT	46,258,749	2,359,760	5.1%	2,333,105	5.04%	$ (26,655)
61	395	LABORATORY EQUIPMENT	437,779	22,439	5.1%	22,439	5.13%	$ -
62	396	POWER OPERATED EQUIPMENT	13,798,162	832,914	6.0%	783,748	5.68%	$ (49,166)
63	397	COMMUNICATION EQUIPMENT	2,364,137	264,280	11.2%	324,268	13.72%	$ 59,988
64	398	MISCELLANEOUS EQUIPMENT	2,319,953	85,708	3.7%	61,603	2.66%	$ (24,105)
65	399	OTHER TANGIBLE PROPERTY	0	0	0.0%	0	0.00%	$ -
66	399							
67	399	Total General Plant	412,726,940	25,276,339	6.1%	25,923,034	6.28%	646,695
68	399							
69	399	Total Depreciable Gas Plant	6,365,028,307	150,666,198	2.4%	128,605,642	2.02%	(22,060,556)
70	399							
71	399	Charged to Clearing Accounts	(149,955,945)	(11,744,650)		(11,484,191)		260,459
72	399							
73	399							
74	399	Adjustment to Depreciation Expenses ($'s in Thousands)						(21,800)
75	399	Adjustment to Accumulated Depreciation ($'s in Thousands)						21,800

Note:
1/ Company Exhibit C, Fully Projected, Table 1
2/ Direct Testimony of OCA Witness James Garren

UGI Utilities Inc.
Gas Division
Adjustment to Revise Normalization Period of Rate Case Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Total Rate Case Costs	$ 1,760 [1/]
2		
3	Company Proposed Normalization Period (Years)	1 [1/]
4	OCA Recommended Normalization Period (Years)	2
5		
6	Company Proposed FPFTY Expense	1,760 [1/]
7	OCA Recommended FPFTY Expense	880
8		
9	Adjustment to O&M Expenses	(880)

Note:
[1/] Company Exhibit A, Fully Projected, Schedule D-10

JLR-7

CONFIDENTIAL/REDACTED

UGI Utilities Inc.
Gas Division
Adjustment to Employee Activity Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Company Proposed Employee Activity Costs	$ 583 [1/]
2		
3	Adjustment to O&M Expenses	(583)

Note:
[1/] Company response to I&E-RE-14

JLR-9

CONFIDENTIAL/REDACTED

UGI Utilities Inc.
Gas Division
Adjustment to Payroll Taxes
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	FICA Expense - Percent	7.57% [1/]
2	FUTA Expense - Percent	0.01% [1/]
3	SUTA Expense -Percent	0.39% [1/]
4		
5	OCA Vacancy Rate Adjustment	$ (1,100) [2/]
6	FICA Adjustment	$ (83)
7	FUTA Adjustment	$ (0)
8	SUTA Adjustment	$ (4)
9		
10	Adjustment to Taxes Other than Income Tax	(88)

Note:
[1/] Company Exhibit A, Fully Projected, Schedule D-32
[2/] Schedule JLR-9

UGI Utilities Inc.
Gas Division
Adjustment to Employee Benefits to Reflect Vacancy Rate Revision
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Employee Pensions and Benefits in FERC Account 926	$ 15,367 [1/]
2	Less: Pension Expense	$ (1,531) [1/]
3	Less: OPEB Expense	$ (1,419) [1/]
4	Benefits Expense to be Adjusted	$ 18,317
5		
6	Company Proposed Vacancy Rate	4.70% [2/]
7	OCA Recommended Vacancy Rate	6.15% [3/]
8		
9	Company Adjustment to Employee Benefits for Vacancy Rate	$ (861)
10	OCA Recommended Adjustment to Employee Benefits for Vacancy Rate	$ (1,127)
11		
12	Adjustment to O&M Expenses	(266)

Note:
[1/] Company response to I&E-RE-28, Attachment I&E-RE-28-(A)
[2/] Company response to I&E-RE-25
[3/] Schedule JLR-9

UGI Utilities Inc.
Gas Division
Adjustment to Advertising Expense - Conservation of Energy
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Conservation of Energy Advertising Expense	
2	FY 2024	$ 73 [1/]
3	FY 2025	$ 235 [1/]
4	Portion specific to Periodic Marketing Campaign	$ 162
5		
6	Normalization (Years)	2
7	Normalized Portion specific to Periodic Marketing Campaign	$ 81
8		
9	Adjustment to O&M Expenses	$ (81)

Note:
[1/] Company response to I&E-RE-43, Attachment I&E-RE-43

UGI Utilities Inc.
Gas Division
Adjustment to Advertising Expense - Other
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Company Proposed Advertising Expense	
2	for Community Event Sponsorships	$ 191 [1/]
3		
4	Adjustment to O&M Expenses	(191)

Note:
[1/] Company response to I&E-RE-43, Attachment I&E-RE-43

UGI Utilities Inc.
Gas Division
Adjustment to PUC Assessment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description		Amount	
1	Company Proposed PUC Assessment Charges in FPFT	$	6,006	1/
2				
3	Historical PUC Assessment Charges			
4	2023 Invoice	$	3,523	1/
5	2024 Invoice	$	4,550	1/
6	2025 Invoice	$	4,551	1/
7				
8	Average FY 2023-2025	$	4,208	
9				
10	Adjustment to O&M Expenses		(1,798)	

Note:
1/ Company response to I&E-RE-39, Attachment I&E-RE-39(B-C)

UGI Utilities Inc.
Gas Division
Adjustment to Residential Collection Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	2025 Residential Collection Expense	$ 6,194 [1/]
2	OCA Recommended Percentage Share to Shareholders	50% [2/]
3		$ 3,097
4		
5	Adjustment to O&M Expenses	(3,097)

Note:
[1/] Company Response to OCA-15-4
[2/] Direct Testimony of OCA Witness Roger Colton

UGI Utilities Inc.
Gas Division
Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description		Amount	
1	Company Rate Base	$	4,337,392	1/
2	Weighted Cost of Debt		2.640%	2/
3	Adjusted Interest Deduction	$	114,507	
4	Interest Deduction Per Company		102,369	3/
5	Adjustment to Synchronize Interest Expense	$	12,138	
6	Effective State Income Tax Rate		7.49%	
7	Adjustment to State Income Taxes	$	(909)	
8	Federal Income Tax Base	$	11,229	
9	Federal Income Tax Rate		21.00%	
10	Adjustment to Federal Income Taxes	$	(2,358)	

Notes:
1/ Schedule JLR-2, Page 1
2/ Schedule JLR-17
3/ Company Exhibit A, Fully Projected, Schedule D-33

UGI Utilities Inc.
Gas Division
Calculation of Rate of Return
For the Twelve Months Ended September 30, 2027

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	51.00%	5.17%	2.64%
2	Total Debt	51.00%		2.64%
3				
4	Common Stock Equity	49.00%	8.80%	4.31%
5				
6	Total	100.00%		6.95%

Source:
Direct Testimony of OCA Witness David Garrett

JLR-18

CONFIDENTIAL/REDACTED

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Summary of Rate Base
For the Twelve Months Ended September 30, 2027

Line No.	Description	Amount per Company Filing	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Utility Plant	6,676,559		6,676,559
3	Accumulated Depreciation	(1,736,046)	21,800	(1,714,246)
4	Net Plant in Service	4,940,513	$ 21,800	$ 4,962,313
5				
6	Additions to Net Plant			
7	Working Capital Requirements:			
8	Cash Working Capital	66,523	(2,381)	64,143
9	Materials and Supplies	28,644		28,644
10	Gas Inventory	23,662		23,662
11	Total Additions	118,829	$ (2,381)	$ 116,449
12				
13	Deductions to Net Plant			
14	Customer Deposits	(23,197)		(23,197)
15	Accumulated Deferred Income Taxes	(716,793)		(716,793)
16	Total Deductions	(739,990)	$ -	$ (739,990)
17				
18	Gas Rate Base	4,319,353	$ 19,419	$ 4,338,772

Source: Company Exhibit A, Fully Projected, Schedule C-1

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2027

Line No.	Description	Source	Amount
1	Rate Base per Company Filing	Schedule JLR-19, Page 1	$ 4,319,353
2			
3	OCA Adjustments:		
4			
5	Adjustment to Cash Working Capital	Schedule JLR- 21	(2,381)
6	Adjustment to Accumulated Depreciation	Schedule JLR- 5	21,800
7			
8	Total Ratemaking Adjustments		$ 19,419
9			
10	Adjusted Rate Base per OCA		$ 4,338,772

JLR-20

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UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Working Capital for O&M Expense Per Company	$ 57,012	1/
2	Interest Payments Per Company	$ (9,459)	1/
3	Tax Payment Lag Calculations Per Company	$ 4,570	1/
4	Prepaid Expenses Per Company	$ 14,400	1/
5	Cash Working Capital Requirements Per Company	$ 66,523	1/
6			
7	Revenue Lag Days	57.46	1/
8	O&M Expense Lag Days	27.55	1/
9	Days to mid-point of interest payments	91.25	1/
10			
11	O&M Expenses		
12	O&M Expenses Per Company	$ 695,601	1/
13	OCA Recommended Adjustments to O&M Expenses	$ (14,699)	2/
14	Revised O&M Expenses	$ 680,903	
15	Operating Expenses Per Day	$ 1,865	1/
16	Net (Lead) Lag Days	29.91	1/
17	Revised Working Capital for O&M	55,800	1/
18			
19	Interest Payments		
20	Measure of Value at September 30, 2026	4,319,352	1/
21	OCA Revised Long-term Debt Ratio	45.75%	3/
22	Embedded Cost of Long-term Debt	5.17%	1/
23	Revised Pro forma Interest Expense	102,165	
24	Daily Amount	280	
25	Interest Payment Lag Days	(33.8)	
26	Revised Interest for Working Capital	(9,459)	
27			
28	Tax Payments		
29	Revised Federal Income Tax	46,459	4/
30	Lead (Lag) Payments Days: First Payment	76.00	1/
31	Lead (Lag) Payments Days: Second Payment	17.00	1/
32	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
33	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
34	Revised Weighted Lead (Lag) Dollars	(1,730,610)	
35	Revised Payment Lead (Lag) Days	(37.25)	
36	Net Payment Lead (Lag) Days	20.21	
37	Revised Working Capital Amount	2,572	
38			
39	Revised State Income Tax	10,906	4/
40	Lead (Lag) Payments Days: First Payment	107.00	1/
41	Lead (Lag) Payments Days: Second Payment	17.00	1/
42	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
43	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
44	Revised Weighted Lead (Lag) Dollars	(321,740)	
45	Revised Payment Lead (Lag) Days	(29.50)	
46	Net Payment Lead (Lag) Days	27.96	
47	Revised Working Capital Amount	835	
48			
49	PA Property Tax Working Capital Amount	(113)	1/
50	PURTA Working Capital Amount	107	1/
51	Revised Tax Payment Working Captial Amount	3,401	
52			
53	Prepayments		
54	Prepaid Expenses Working Captial Amount	14,400	1/
55			
56	Adjustment to Rate Base	(2,381)	

Note:
1/ Company Exhibit A, FPFTY, Schedule C-4
2/ Schedule JLR-20
3/ Schedule JLR-23
4/ Schedule JLR-18

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Company Rate Base	$ 4,338,772	1/
2	Weighted Cost of Debt	2.370%	2/
3	Adjusted Interest Deduction	$ 102,829	
4	Interest Deduction Per Company	102,369	3/
5	Adjustment to Synchronize Interest Expense	$ 460	
6	Effective State Income Tax Rate	7.49%	
7	Adjustment to State Income Taxes	$ (34)	
8	Federal Income Tax Base	$ 426	
9	Federal Income Tax Rate	21.00%	
10	Adjustment to Federal Income Taxes	$ (89)	

Notes:
1/ Schedule JLR-19, Page 1
2/ Schedule JLR-23
3/ Company Exhibit A, Fully Projected, Schedule D-33

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Calculation of Rate of Return
For the Twelve Months Ended September 30, 2027

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	45.75%	5.17%	2.37%
2	Total Debt	45.75%		2.37%
3				
4	Common Stock Equity	54.25%	8.50%	4.61%
5				
6	Total	100.00%		6.98%

Source:
Direct Testimony of OCA Witness David Garrett

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Jennifer L. Rogers, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: /s/ *Jennifer L. Rogers*
Jennifer L. Rogers

Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044

OCA St. 2SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2025-3059523**
	)	
UGI Utilities, Inc. – Gas Division	)	
	)	

CONFIDENTIAL SURREBUTTAL TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2026

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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Schedules Accompanying Surrebuttal Testimony:

- Surrebuttal Schedules JLR-1 Through JLR-23

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer L. Rogers. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Principal and Vice President at Exeter Associates, Inc. ("Exeter"). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME JENNIFER L. ROGERS WHO SUBMITTED DIRECT TESTIMONY ON APRIL 13, 2026 IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to address issues discussed in the Rebuttal Testimony of UGI Utilities, Inc. – Gas Division ("UGI" or "Company") witnesses Tracy A. Hazenstab, Vivian K. Ressler, Daniel V. Adamo, and Amy M. Keller, which was filed on May 13, 2026.

Q. ARE YOU INCLUDING UPDATED SCHEDULES SUMMARIZING THE OCA'S CURRENT REVENUE REQUIREMENT POSITION IN THIS PROCEEDING?

A. Yes. I have attached Surrebuttal Schedules JLR-1 to JLR-23 to this testimony which present the OCA's updated position after taking the Company's rebuttal position into account. My Surrebuttal Schedules utilize the Company's Rebuttal Filing Schedules as the basis of Company data, as these reflect the Company's updated position in this case. In this testimony, I respond to the Company's witnesses' Rebuttal Testimonies on various adjustments I recommended in my Direct Testimony. I have considered the issues addressed in Rebuttal Testimony and discuss these in the Section below. I have determined my revised recommendation that UGI's proposed revenue increase should

be reduced to reflect a decrease of $15.4 million for the FPFTY, based on the OCA's primary recommendation of 8.8% authorized ROE and 51% debt ratio, which is per the recommendation detailed in the Direct Testimony of OCA Witness David Garrett.

As discussed in my Direct Testimony, OCA Witness Garret has proposed this as his primary recommendation. If, however, the Commission adopts UGI's capital structure, then utilizing the OCA's alternative recommendation of an 8.5% ROE, I have determined that UGI's proposed revenue increase should be reduced to reflect a decrease of $9.1 million for the FPFTY, as shown on Surrebuttal Schedule JLR-18.

To the extent that a Company witness's Rebuttal Testimony has addressed my position on an issue developed in my Direct Testimony, but I do not address it in this Surrebuttal Testimony, it should not be construed that I agree with the Company.

II. ADJUSTMENTS

A. Energy Efficiency and Conservation

Q. PLEASE ADDRESS THE REBUTTAL TESTIMONY OF COMPANY WITNESS HAZENSTAB RELATED TO ENERGY EFFICIENCY AND CONSERVATION ("EE&C").

A. In Rebuttal, Company Witness Hazenstab addresses a proposed adjustment to EE&C and attributes it to "OCA witness Walker".[1] To clarify, OCA has not proposed an adjustment to EE&C. Mr. Walker is an I&E witness.

B. Allowance for Cash Working Capital

Q. PLEASE ADDRESS THE REBUTTAL TESTIMONY OF COMPANY WITNESS HAZENSTAB RELATED TO CASH WORKING CAPITAL.

A. As Company Witness Hazenstab notes in Rebuttal, we agree on the methodology used to calculate the cash working capital. However, as expenses serve as the basis upon

[1] Rebuttal Testimony of Tracy A. Hazenstab, 7: 1.

which the cash working capital is calculated, we continue to differ on the final calculated amount.[2] I have incorporated the adjustments to O&M expenses that I am recommending in this Surrebuttal. I have therefore made an adjustment to cash working capital to decrease the Company's rebuttal position rate base by $3.5 million, as shown on Surrebuttal Schedule JLR-4.

C. Depreciation Expense

Q. PLEASE EXPLAIN COMPANY WITNESS KELLER'S REBUTTAL TESTIMONY RELATING TO THE DEPRECIATION EXPENSE ADJUSTMENTS ACCUMULATED DEPRECIATION AND ADIT.

A. In my Direct Testimony, I applied the depreciation recommendations per the direct testimony of OCA witness Garren to the calculation of depreciation expenses.[3] In discovery, I acknowledged the need for an additional adjustment to ADIT, which I stated would be addressed in Surrebuttal.[4] In Rebuttal, Company Witness Keller noted that while the Company did not recommend the depreciation adjustment, if it is accepted, they calculated a $257 million adjustment to accumulated depreciation, and $37 million for the related ADIT adjustment, based on a restatement of accumulated depreciation from 1982 through the present.[5]

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF THE ADJUSTMENT TO ACCUMULATED DEPRECIATION AND ADIT?

A. No, I do not. While I do agree there would be a related adjustment to ADIT in addition to the depreciation expense and accumulated depreciation adjustments shown in my Direct Testimony, the changes should be prospective. It is my understanding that OCA Witness Garren is not recommending a restatement of past depreciation. The

[2] Rebuttal Testimony of Tracy A. Hazenstab, 8: 14-18.
[3] Direct Testimony of Jennifer L. Rogers, 6: 19-24, 7:1-5.
[4] Direct Testimony of Jennifer L. Rogers, 7: 2-5.
[5] Rebuttal Testimony of Amy M. Keller, 3: 8-21, 4: 1-18, and UGI Gas Exhibit AMK-2R.

Company is calculating an accumulated depreciation change from 1982 to present. However, to align with Witness Garren's recommendation, only the FPFTY values would be impacted, not the existing depreciation reserve. Rates would be revised going forward.

Q. WHAT IS YOUR RECOMMENDATION?

A. I continue to reflect the recommendations of OCA Witness Garren, as detailed in his Direct and Surrebuttal Testimonies. These adjustments are shown on Surrebuttal Schedule JLR-5. The information provided in Rebuttal by the Company related to ADIT does not reflect the prospective change OCA has recommended, and I have therefore continued to exclude it, given the lack of available information on the appropriate amount.

D. Rate Case Expense

Q. PLEASE EXPLAIN THE COMPANY'S REBUTTAL TESTIMONY RELATED TO RATE CASE EXPENSE.

A. In its initial filing, the Company presented a total rate case expense of $1.76 million, normalized over one year, resulting in an annual recovery of $1.76 million for the FPFTY rate case expense.[6] In my Direct Testimony, I recommended normalizing the Company's proposed rate case expense over the average length of time between its three most recent filings, consistent with the Commission's policy to set a normalization period based upon historic filing frequency.[7] In Rebuttal, Company witness Hazenstab disagrees with this adjustment on the basis that the Company expects to file its next case in one year.[8]

[6] Company Exhibit A, Fully Projected, Schedule D-10.
[7] Direct Testimony of Jennifer L. Rogers, 7: 7-19.
[8] Rebuttal Testimony of Tracy A. Hazenstab, 6: 9-19.

Q. DO YOU AGREE WITH COMPANY WITNESS HAZENSTAB'S RECOMMENDATION TO USE A NORMALIZATION PERIOD THAT IS LESS THAN THE AVERAGE TIME BETWEEN RATE CASES?

A. No, I do not. While the Company states that it believes it will file its next case sooner than two years, timelines for a Company's rate case filings are subject to any number of factors and variabilities. To use the historical filing frequency of recent cases to determine the normalization period is a method to base costs applied to ratepayers on actual data and evidence rather than a Company's supposition on their general intended timing which would be unreliable. It is also, as I explained in my Direct Testimony, the method in line with established Commission practice.[9] The recovery of rate case expense should be spread over the period that benefits from incurring the rate case expense, which would be typically measured as the historical period between rate cases. I therefore continue to recommend that the normalization period be increased to two years. This results in a decrease to O&M expenses of $880,000, as shown on Surrebuttal Schedule JLR-6.

E. Incentive Compensation Expense

Q. PLEASE EXPLAIN COMPANY WITNESS RESSLER'S REBUTTAL TESTIMONY RELATED TO INCENTIVE COMPENSATION.

A. The Company offers several incentive plans, including UGI Utilities Inc.'s Management Incentive Plan, Executive and Non-Executive Annual Bonus Plans, Sales Commission Plan, Discretionary Bonus Policy, Inside Sales Group Incentive Plan, Customer Care Scorecard and Incentive Plan, and Equity Compensation Plans.[10] In my Direct Testimony, I recommended disallowing the inclusion of the portion of the incentive compensation which primarily benefits shareholders. In the

[9] Reference Direct Testimony of Jennifer L. Rogers, 7: 14-16.
[10] UGI Company Filing Book II, SDR-RR-27, and Attachments SDR-RR-27.1 through SDR-RR-27.7.

FPFTY, I therefore recommended **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In Rebuttal, Company Witness Ressler disagreed with my recommendation and presented several arguments in response, which I address below.

Q. MS. RESSLER ARGUES THAT INCENTIVE COMPENSATION MUST BE EVALUATED "AS A WHOLE" AND THAT BREAKING OUT A COMPONENT OF THE PLANS IS INAPPROPRIATE.[13] DO YOU AGREE?

A. No, I do not. First, this is at odds with the rate setting process itself, wherein the Commission determines the appropriate costs to include in rates. To be barred from challenging an individual cost element simply because it exists within a larger category would undermine the Commission's ability to set just and reasonable rates. Further, the Commission recently confirmed in a 2025 Columbia Gas proceeding that it is entirely appropriate to allow recovery of the portion of incentive compensation tied to operational safety and customer experience metrics while disallowing the portion tied to financial metrics.[14]

[redacted]

[13] Rebuttal Testimony of Vivian K. Ressler, 6: 17-26 and 8: 5-15.
[14] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2025-3053499 (Opinion and Order entered December 4, 2025), at pp. 123, 126

Q. MS. RESSLER CITES SEVERAL COMMISSION ORDERS - INCLUDING PPL ELECTRIC, AQUA PENNSYLVANIA, AND PENNSYLVANIA-AMERICAN WATER COMPANY - AS PRECEDENT FOR THE COMMISSION ALLOWING FULL RECOVERY OF THE COMPANY'S INCENTIVE COMPENSATION.[15] DO THOSE ORDERS REQUIRE THAT RESULT HERE?

A. No, the Commission has decided to allow and disallow such adjustments in the past – it is not a uniform precedent. In each of those cases cited by the Company, the Commission allowed recovery because the utility demonstrated that its incentive compensation program provided a benefit to ratepayers, per the evidence presented in each unique case. That evidence is what drives the result, not the existence of an incentive compensation program itself. In the recent Columbia Gas proceeding, the Commission adopted OCA's recommended disallowance of the portions of the Company's incentive compensation tied to financial metrics, finding that Columbia Gas had not explained why those portions were necessary to provide adequate service to ratepayers.[16]

Q. MS. RESSLER ARGUES THAT THE PORTIONS OF INCENTIVE COMPENSATION I HAVE TARGETED BENEFIT RATEPAYERS THROUGH THE FINANCIAL SUCCESS OF THE COMPANY AND SHOULD THEREFORE BE ALLOWED.[17] DO YOU AGREE?

A. No. Any incidental overlap between financial success and ratepayer benefit does not mean ratepayers should fund employee compensation that is designed to drive outcomes that primarily benefit shareholders. As explained in my Direct Testimony,

[15] Rebuttal Testimony of Vivian K. Ressler, 5: 21-23, 6: 1-16 and 27-28, 7: 1-20.
[16] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499 (Opinion and Order entered December 4, 2025), at pp. 123, 126.
[17] Rebuttal Testimony of Vivian K. Ressler, 5: 6-19.

the primary beneficiaries of financial metrics are shareholders, not ratepayers, and the interests of shareholders and ratepayers are not always aligned. Incentive structures that emphasize financial performance can encourage management to prioritize profitability over affordability or operational efficiency. In my opinion, Ms. Ressler incorrectly generalizes that any increased financial performance ultimately benefits the ratepayers, however a company act can adversely impact the interests of ratepayers while being favorable to shareholders. For example, a company could defer necessary infrastructure maintenance to reduce costs and boost earnings, which would benefit shareholders in the short term while leaving ratepayers with a degraded, less reliable system.

Q. MS. RESSLER ARGUES THAT DISALLOWING THE FINANCIAL COMPONENTS OF THE COMPANY'S INCENTIVE COMPENSATION PROGRAM WOULD UNDERMINE UGI'S ABILITY TO ATTRACT AND RETAIN QUALIFIED EMPLOYEES AND EXECUTIVES.[18] HOW DO YOU RESPOND?

A. My position is not that the Company should eliminate its incentive compensation. The issue is whether ratepayers must fund every element of that compensation package regardless of who primarily benefits from it - who bears the cost of particular components. As explained in my Direct Testimony, shareholders are the primary beneficiaries of the outcomes from the portions of the incentive compensation plans I recommend disallowing. Ratepayers should not be obligated to subsidize the shareholder-oriented portions of those packages. If desired, the Company can continue to offer incentives to promote shareholder benefit, at shareholder expense.

[18] Rebuttal Testimony of Vivian K. Ressler, 4: 19-23.

Q. MS. RESSLER ARGUES THAT IF THE COMMISSION DISALLOWS THE FINANCIAL COMPONENTS OF THE COMPANY'S INCENTIVE COMPENSATION, THE COMPANY WOULD NEED TO REPLACE THEM WITH ALTERNATIVE INCENTIVE COMPENSATION OR HIGHER BASE SALARIES.[19] DO YOU AGREE?

A. No, I do not. This argument is speculative and, if accepted, would effectively immunize any incentive compensation structure from scrutiny. The premise assumes any disallowance would automatically be offset by equivalent increases elsewhere. The Company has not provided evidence that base salaries would in fact be increased, or by how much, if this adjustment is adopted. Regulatory proceedings routinely involve adjustments to components of a utility's cost of service without the assumption that the company will immediately replace the disallowed cost with an equivalent expenditure.

Q. DO YOU HAVE ANY OTHER RESPONSE TO MS. RESSLER'S REBUTTAL OF YOUR INCENTIVE COMPENSATION ADJUSTMENT?

A. Yes. Ms. Ressler states that "…the plans for which OCA Witness Rogers proposes to disallow 80% of the claimed compensation … are all goals-based incentive compensation which motivate the Company's talent."[20] Per the Company's own discovery responses, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** - meaning they are designed to motivate employees to achieve outcomes that benefit shareholders. Ratepayers should not be required to fund that portion of the motivation. **[BEGIN**

[19] Rebuttal Testimony of Vivian K. Ressler, 8:1-3.
[20] Rebuttal Testimony of Vivian K. Ressler, 19: 15-18.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**[21]

Q. WHAT IS YOUR RECOMMENDATION?

A. As explained in my Direct Testimony, a fundamental principle of ratemaking is that costs should be assigned to those who benefit from them. In the case of incentive compensation tied to financial performance, the primary beneficiaries are shareholders. I continue to recommend disallowing incentive compensation expenses related to financial metrics. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

F. Employee Activity Expense

Q. PLEASE EXPLAIN COMPANY WITNESS RESSLER'S REBUTTAL TESTIMONY RELATED TO EMPLOYEE ACTIVITY EXPENSE.

A. In its filing, the Company proposed including costs totaling $583,036 in the cost of service related to employee activities, which are for items such as picnics, parties, and safety awards.[22] In my Direct Testimony, I recommended disallowing these expenses as they do not relate to the provision of safe and reliable utility service.[23] In Rebuttal, the Company disagreed with this disallowance, citing the various functions of each award.[24]

[21] Company response to I&E-RE-32, CONFIDENTIAL Attachment I&E-RE-32.7 and CONFIDENTIAL Attachment I&E-RE-32.8
[22] UGI Company Filing Book II, SDR-RR-30(e).
[23] Direct Testimony of Jennifer L. Rogers, 10: 17-22.
[24] Rebuttal Testimony of Vivian K. Ressler, 20: 12-24 and 21: 1-34.

Q. ARE YOU REVISING YOUR RECOMMENDATION REGARDING EMPLOYEE ACTIVITY EXPENSE?

A. Yes, in part. Upon further consideration and review, I am revising my recommended disallowance from $583,036 to $195,000, limiting my recommendation to disallow only the cost of the Company picnic. With respect to the picnic expenses, in Rebuttal, Company Witness Ressler cites a 2018 Commission order *Pa. PUC, et al. v. UGI 4 Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Opinion and Order entered 5 October 25, 2018) as precedent to allow the picnic in expenses. It is important to note, however, that the Order goes on to say:

> In *York Water*, the Commission granted the utility's expense claim for a company banquet but did not grant the utility's expense claim for a company picnic. The distinction made in *York Water* between the company picnic and the company banquet, was based upon the conclusion that the company picnic did not stand on the same footing as the company banquet, since it involved no element of employee recognition. Similarly, in *Columbia Water*, the ALJ disallowed employee recognition expenses because the utility did not provide specific information about the year-end banquet to demonstrate that it qualifies as an employee recognition dinner.[25]

Witness Ressler gave a general characterization in Rebuttal that the picnic has the goal of recognizing and celebrating employees but provided no evidence that it does so or specific detail regarding the event to support the comment.[26]

Regardless, a company picnic is not an expense that relates to the provision of safe and reliable utility service to ratepayers and should therefore not be ratepayer responsibility. I therefore maintain my recommendation to disallow the $195,000

[25] *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, Opinion and Order entered October 25, 2018, at pp. 70-71.
[26] Rebuttal Testimony of Vivian K. Ressler, 21: 29-34.

picnic expense from the cost of service. This adjustment is shown on Surrebuttal Schedule JLR-8.

G. Vacancy Reserve

Q. PLEASE ADDRESS COMPANY WITNESS RESSLER'S REBUTTAL TESTIMONY RELATED TO VACANCY RATE.

A. In its filing, the Company applied a vacancy rate of 4.7% to its labor expense.[27] In my Direct Testimony, I noted that this was abnormally low compared to the actual level of vacancies experienced over the past three years and recommended the Company utilize a vacancy rate of 6.15%, which is the average of the most recent three years, to avoid over collecting from customers. In Rebuttal, Company Witness Ressler accepted the use of a 6.15% vacancy rates to limit the scope of issues in dispute. The Company applied the adjustment per I&E Witness Walker's calculations.[28] I&E Witness Walker's calculation of the related adjustments to payroll, payroll tax, and employee benefits varies slightly from mine (e.g., I flowed through my incentive compensation adjustment to the payroll calculation). While I believe my calculations are correct, I accept the Company's proposed adjustment utilizing I&E Witness Walker's figures to reduce the contested issues in this case. This issue is therefore resolved.

H. Advertising Expense – Conservation of Energy

Q. PLEASE ADDRESS COMPANY REBUTTAL PERTAINING TO ADVERTISING EXPENSE RELATED TO CONSERVATION OF ENERGY.

A. In their filing, the Company stated it expects to have $272,515 in expenses related to Conservation of Energy in the FPFTY, related to a fuel campaign run in FY 2025 that was not run in 2024 or 2023. In my Direct Testimony, I explained that the costs

[27] Company response to I&E-RE-25.
[28] Rebuttal Testimony of Vivian K. Ressler, 3:14-23.

represent an intermittent advertising campaign, rather than a normal, recurring annual expense. I therefore recommended isolating the non-recurring portion of the expense and normalizing it for recovery over two years.[29] Accordingly, it is inappropriate to include these costs in rates as a recurring annual expense. In Rebuttal, the Company states these campaigns will be continued regularly, on at least an annual basis.[30]

Q. DO YOU STILL RECOMMEND REMOVING THESE COSTS FROM THE COST OF SERVICE?

A. No, I do not. Given that the expenses will be incurred annually, I am withdrawing the adjustment of $81,187. This change has been incorporated into my attached Surrebuttal Schedules.

I. Advertising Expense - Other

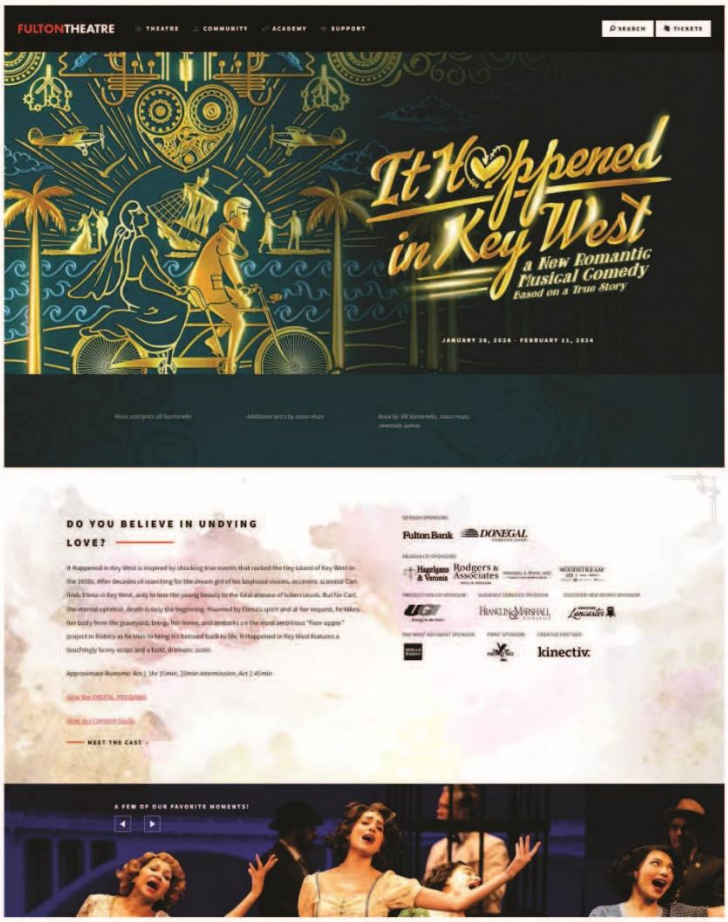
Q. PLEASE EXPLAIN THE COMPANY'S REBUTTAL RELATED TO "OTHER ADVERTISING PROGRAMS" EXPENSES.

A. In its filing, the Company included an Other Advertising Programs expense of $380,397 for the FPFTY of which $191,149 is attributed to community event sponsorships and $189,249 is attributed to stakeholder newsletters.[31]. In my Direct Testimony, I recommended disallowing the expense associated with community event sponsorships, as this advertising expense is largely promotional in nature and does not relate to the provision of safe, reliable, and adequate utility service to ratepayers, and therefore should not be ratepayer responsibility.[32] In rebuttal, the Company disagreed with this adjustment on the basis that community event sponsorships connect them with communities and home builders.[33]

[29] Direct Testimony of Jennifer L. Rogers, 12: 14-23 and 13: 1-20.
[30] Rebuttal Testimony of Tracy A. Hazenstab, 4: 19-23.
[31] Company response to I&E-RE-43, Attachment I&E-RE-43.
[32] Direct Testimony of Jennifer L. Rogers, 14: 10-14.
[33] Rebuttal Testimony of Vivian K. Ressler, 24: 5-23 and 25:1-12.

Q. DO YOU AGREE WITH THE COMPANY'S ASSERTION IN REBUTTAL THAT IT IS APPROPRIATE TO APPLY COMMUNITY EVENT SPONSORSHIP EXPENSES TO RATEPAYERS?

A. No, I do not. The Company asserts that community event sponsorship is a means of connecting with communities, however the messaging once connected is the distinguishing element for whether an advertising expense is appropriate to recover from ratepayers. Expenses related to image building should not be passed on to ratepayers. Below is an example of this type of advertising, which the Company provided in Attachment I&E-RE-44:


FULTONTHEATRE
THEATRE
COMMUNITY
ACADEMY
SUPPORT
SEARCH
TICKETS
It Happened in Key West
a New Romantic Musical Comedy
Based on a True Story
DO YOU BELIEVE IN UNDYING LOVE?
Fulton Bank
DONEGAL
Rodgers & Associates
kinectiv.
MEET THE CAST
A FEW OF OUR FAVORITE MOMENTS!

1

The Company states these events allow customers to connect to the company and "receive information about billing, customer programs, safety, or utility services."[34] There is no apparent link between the advertising and providing safe and reliable service to ratepayers, and I find it unlikely that such events are the most effective method of informing members of the public about natural gas. I do not believe the Company has sufficiently justified applying this expense to ratepayers, and I therefore continue to recommend disallowing the expense. This reduces expenses by $191,149, as shown in Surrebuttal Schedule JLR-13.

J. PUC Assessment

Q. PLEASE EXPLAIN THE COMPANY'S REBUTTAL RELATED TO THE PUC ASSESSMENT EXPENSE.

A. In its filing, the Company derived its PUC Assessment expense projection by taking the 2025 invoice amount and multiplying it by a 14.9% increase to reach a projected 2026 invoice amount, and then again to reach a 2027 invoice amount. The Company derived the 14.9% increase as the average percentage increase over 2022 to 2025. This results in an increase in PUC Assessment expenses from the HTY amount of $4.551 million to $6.006 million in the FPFTY. [35] In my Direct Testimony, I explained that the PUC Assessment charge was variable, and applying a linear increase to an expense item that may not increase risked overcollection from customers. I recommended normalizing the expense by taking the average of the most recent three years to determine a representative annual cost for ratemaking.[36] In Rebuttal, the Company agreed the expense is varied, but argued that the Company's methodology was more accurate for projecting the FPFTY expenses.[37]

[34] Rebuttal Testimony of Vivian K. Ressler, 24: 5-10.
[35] Company response to I&E-RE-39, Attachment I&E-RE-39(B-C).
[36] Direct Testimony of Jennifer L. Rogers, 15: 3-10.
[37] Rebuttal Testimony of Vivian K. Ressler, beginning 30: 18, ending 33: 19.

Q. DO YOU AGREE WITH THE COMPANY THAT THEIR APPROACH IS MORE REASONABLE?

A. No, I do not. Company Witness Ressler presents Exhibit VKR-3R to demonstrate that the Company's trending methodology more accurately projected the 2025 PUC assessment invoice than the OCA's three-year average approach. I do not find this argument persuasive. The Company's assertions that this expense will grow are speculative. Indeed, Company Witness Ressler concedes that this expense is variable from year to year, increasing and decreasing over time.[38] The year-over-year percentage changes underlying the Company's methodology reflect exactly that variability, swinging from approximately +24.8 percent, to -13.2 percent, to +15.5 percent in the three sample years utilized in Exhibit VKR-3R. This series does not reflect a stable underlying trend. When the inputs to a trending methodology are this inconsistent, the resulting growth rate is not a meaningful basis for projecting future expense levels.

Q. WHY IS THE OCA'S THREE-YEAR AVERAGE A MORE APPROPRIATE METHODOLOGY GIVEN THAT VOLATILITY?

A. The three-year average methodology is more appropriate because the volatility itself is the reason to average actuals rather than trend. When an expense moves unpredictably from year to year, the appropriate ratemaking approach is to normalize it using recent actual experience - not to project it using a growth rate derived from that same unpredictable history. The OCA's three-year average of 2023, 2024, and 2025 invoices reflects what ratepayers have actually been assessed in recent years and provides a reasonable, normalized annual cost for ratemaking purposes.

[38] Rebuttal Testimony of Vivian K. Ressler, 30: 22-23 and 31: 16.

As shown in the Company's own rebuttal testimony, the PUC assessment invoice was essentially flat from 2024 to 2025, increasing by only $1,000 on a base of $4,550,000 - effectively zero growth. The Company nonetheless projects the 2027 invoice at $6,006,000, an increase of approximately 32 percent above the 2025 actual. That projection assumes a resumption of steep growth that is directly contradicted by the most recent data.

Q. HAVE YOU REVISED YOUR RECOMMENDATION RELATED TO THE PUC ASSESSMENT EXPENSES?

A. No, I have not. For the reasons explained above, I maintain my recommendation to reduce the Company's claimed PUC assessment expense by $1.8 million, as shown on Surrebuttal Schedule JLR-14.

K. Residential Collection Expense

Q. PLEASE ADDRESS THE COMPANY'S REBUTTAL RELATED TO RESIDENTIAL COLLECTION EXPENSE.

A. I have applied the recommendation per the direct and surrebuttal testimonies of OCA witness Roger Colton, removing 50 percent of the residential collection expenses. In Direct Testimony, I stated the Company was unable to provide the exact dollar amount of residential collection expenses included in the FPFTY, stating the expense is embedded in a FERC Account which includes other costs as well. I therefore used the 2025 residential collection expense value as a proxy.[39] In Rebuttal, Company Witness Adamo states the dollar amount was provided in Attachment OCA-15-7.[40] Per OCA witness Colton's Surrebuttal, I have continued to use the value provided in response to OCA-15-4. As shown on Surrebuttal Schedule JLR-15, this adjustment decreases O&M expenses by $3 million.

[39] Direct Testimony of Jennifer L. Rogers, 15: 19-22 and 16: 1-2.
[40] Rebuttal Testimony of Daniel V. Adamo, 19: 20-21 and 20: 1.

L. Interest Synchronization

Q. PLEASE ADDRESS THE COMPANY'S REBUTTAL RELATED TO INTEREST SYNCHRONIZATION.

A. While the Company does not disagree with my method of calculation, we disagree on the rate base and weighted cost of debt values on which it is based, and therefore we continue to disagree on the resulting flow through amount. Further, the Company states it has incorporated an adjustment to the average cost of long-term debt in the Rebuttal calculation of the interest deduction.[41] I have calculated the interest synchronization based on OCA witness Garrett's recommendations, as detailed in his Direct and Surrebuttal Testimonies. This adjustment decreases state income taxes by $845,000 and federal income taxes by $2.2 million, as shown in Surrebuttal Schedule JLR-16.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

[41] Rebuttal Testimony of Tracy A. Hazenstab, 10: 1-17.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2025-3059523**
	)	
UGI Utilities, Inc. – Gas Division	)	

SCHEDULES ACCOMPANYING THE SURREBUTTAL TESTIMONY OF JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2026

STATEMENT 2SR

Surrebuttal Schedule JLR-1

Contains Confidential Information.

Only this placeholder has been included in the Public version of Statement 2SR.

UGI Utilities Inc.
Gas Division
Summary of Rate Base
For the Twelve Months Ended September 30, 2027

Line No.	Description	Amount per Company Filing [1/]	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Utility Plant	6,676,559		6,676,559
3	Accumulated Depreciation	(1,736,046)	21,800	(1,714,246)
4	Net Plant in Service	4,940,513	$ 21,800	$ 4,962,313
5				
6	Additions to Net Plant			
7	Working Capital Requirements:			
8	Cash Working Capital	66,348	(3,533)	62,815
9	Materials and Supplies	28,644		28,644
10	Gas Inventory	23,662		23,662
11	Total Additions	118,654	$ (3,533)	$ 115,121
12				
13	Deductions to Net Plant			
14	Customer Deposits	(23,197)		(23,197)
15	Accumulated Deferred Income Taxes	(716,793)		(716,793)
16	Total Deductions	(739,990)	$ -	$ (739,990)
17				
18	Gas Rate Base	4,319,177	$ 18,267	$ 4,337,444

Note:
[1/] Company Rebuttal Exhibit A, Fully Projected, Schedule C-1

UGI Utilities Inc.
Gas Division
Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2027

Line No.	Description	Source	Amount
1	Rate Base per Company Rebuttal	Surrebuttal Schedule JLR-2, Page 1	$ 4,319,177
2			
3	OCA Adjustments:		
4			
5	Adjustment to Cash Working Capital	Surrebuttal Schedule JLR- 4	(3,533)
6	Adjustment to Accumulated Depreciation	Surrebuttal Schedule JLR- 5	21,800
7			
8	Total Ratemaking Adjustments		$ 18,267
9			
10	Adjusted Rate Base per OCA		$ 4,337,444

STATEMENT 2SR

Surrebuttal Schedule JLR-3

Contains Confidential Information.

Only this placeholder has been included in the Public version of Statement 2SR.

UGI Utilities Inc.
Gas Division
Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Working Capital for O&M Expense Per Company	$ 56,928	1/
2	Interest Payments Per Company	$ (9,550)	1/
3	Tax Payment Lag Calculations Per Company	$ 4,570	1/
4	Prepaid Expenses Per Company	$ 14,400	1/
5	Cash Working Capital Requirements Per Company	$ 66,348	
6			
7	Revenue Lag Days	57.46	1/
8	O&M Expense Lag Days	27.57	1/
9	Days to mid-point of interest payments	91.25	1/
10			
11	O&M Expenses		
12	O&M Expenses Per Company	$ 695,199	1/
13	OCA Recommended Adjustments to O&M Expenses	$ (12,864)	2/
14	Revised O&M Expenses	$ 682,335	
15	Operating Expenses Per Day	$ 1,869	
16	Net (Lead) Lag Days	29.88	
17	Revised Working Capital for O&M	55,852	
18			
19	Interest Payments		
20	Measure of Value at September 30, 2026	4,319,177	1/
21	OCA Revised Long-term Debt Ratio	51.00%	3/
22	Embedded Cost of Long-term Debt	5.17%	3/
23	Revised Pro forma Interest Expense	113,884	
24	Daily Amount	312	
25	Interest Payment Lag Days	(33.8)	
26	Revised Interest for Working Capital	(10,544)	
27			
28	Tax Payments		
29	Revised Federal Income Tax	42,983	4/
30	Lead (Lag) Payments Days: First Payment	76.00	1/
31	Lead (Lag) Payments Days: Second Payment	17.00	1/
32	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
33	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
34	Revised Weighted Lead (Lag) Dollars	(1,601,129)	
35	Revised Payment Lead (Lag) Days	(37.25)	
36	Net Payment Lead (Lag) Days	20.21	
37	Revised Working Capital Amount	2,380	
38			
39	Revised State Income Tax	9,566	4/
40	Lead (Lag) Payments Days: First Payment	107.00	1/
41	Lead (Lag) Payments Days: Second Payment	17.00	1/
42	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
43	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
44	Revised Weighted Lead (Lag) Dollars	(282,196)	
45	Revised Payment Lead (Lag) Days	(29.50)	
46	Net Payment Lead (Lag) Days	27.96	
47	Revised Working Capital Amount	733	
48			
49	PA Property Tax Working Capital Amount	(113)	1/
50	PURTA Working Capital Amount	107	1/
51	Revised Tax Payment Working Captial Amount	3,106	
52			
53	Prepayments		
54	Prepaid Expenses Working Captial Amount	14,400	1/
55			
56	Adjustment to Rate Base	(3,533)	

Note:
1/ Company Rebuttal Exhibit A, Fully Projected, Schedule C-4
2/ Surrebuttal Schedule JLR-3
3/ Surrebuttal Schedule JLR-17
4/ Surrebuttal Schedule JLR-1

UGI Utilities Inc.
Gas Division
Adjustment to Depreciation Expense
For the Twelve Months Ended September 30, 2027
(Total $'s)

Line No.	Account No.	Description	ORIGINAL COST 1/	Per Company Accrual Amount 1/	Per Company Rate 1/	OCA Recommendation Accrual Amount 2/	OCA Recommendation Rate 2/	Difference
1								
2		**Production Plant**						
3	305	MANUFACTURED GAS PLANT SITE REMEDIATION	-	-	0.0%	0	0.00%	$ -
4	329	OTHER STRUCTURES	-	-	0.0%	0	0.00%	$ -
5	332	FIELD LINES	-	-	0.0%	0	0.00%	$ -
6	335	DRILLING AND CLEANING EQUIPMENT	-	-	0.0%	0	0.00%	$ -
7								
8		Total Production Plant	-	-	0.0%	-	0.00%	-
9								
10		**Transmission Plant**						
11	365.2	RIGHTS-OF-WAY	868,160	10,902	1.3%	11,329	1.30%	$ 427
12	366	STRUCTURES AND IMPROVEMENTS	162,216	271	0.2%	801	0.49%	$ 530
13	367	MAINS	39,468,181	399,385	1.0%	383,965	0.97%	$ (15,420)
14	369	MEASURING AND REGULATING STATION EQUIPMENT	6,172,834	86,642	1.4%	82,871	1.34%	$ (3,771)
15	370	COMMUNICATION EQUIPMENT	3,505,204	76,632	2.2%	69,544	1.98%	$ (7,088)
16	371	OTHER EQUIPMENT	140,637	787	0.6%	991	0.70%	$ 204
17	371.1	TESTING EQUIPMENT	210,011	4,216	2.0%	7,922	3.77%	$ 3,706
18								
19		Total Transmission Plant	50,527,243	578,835	1.1%	557,423	1.10%	(21,412)
20								
21		**Distribution Plant**						
22	374.2	RIGHTS-OF-WAY	3,374,004	42,665	1.3%	38,909	1.15%	$ (3,756)
23	375	STRUCTURES AND IMPROVEMENTS	7,923,019	144,227	1.8%	73,545	0.93%	$ (70,682)
24	376.1	MAINS - PRIMARILY STEEL	816,343,179	12,366,899	1.5%	9,669,065	1.18%	$ (2,697,834)
25	376.2	MAINS - CAST IRON	664,766	0	0.0%	(0)	0.00%	$ (0)
26	376.3	MAINS - PLASTIC	2,371,718,284	38,991,101	1.6%	34,120,044	1.44%	$ (4,871,057)
27	376.5	MAINS - PRIMARILY WROUGHT IRON	305,201	4,749	1.6%	3,893	1.28%	$ (856)
28	376.7	REG AFUDC	1,322,088	33,052	2.5%	29,356	2.22%	$ (3,696)
29	378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	229,058,181	6,274,505	2.7%	3,750,928	1.64%	$ (2,523,577)
30	379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	81,779,825	2,234,071	2.7%	1,663,771	2.03%	$ (570,300)
31	380	SERVICES	1,937,403,605	51,721,129	2.7%	41,176,455	2.13%	$ (10,544,674)
32	381	METERS	169,884,761	4,671,295	2.7%	4,089,395	2.41%	$ (581,900)
33	381.1	METERS - ERTS	49,518,244	3,179,453	6.4%	3,045,718	6.15%	$ (133,735)
34	382	METER INSTALLATIONS	153,631,673	3,708,944	2.4%	3,062,777	1.99%	$ (646,167)
35	383	HOUSE REGULATORS	10,274,123	206,374	2.0%	187,231	1.82%	$ (19,143)
36	384	HOUSE REGULATOR INSTALLATIONS	17,829,357	318,884	1.8%	296,359	1.66%	$ (22,525)
37	385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	42,670,641	797,604	1.9%	742,234	1.74%	$ (55,370)
38	386	OTHER PROPERTY ON CUSTOMERS PREMISES	68,824	1,414	2.1%	1,279	1.86%	$ (135)
39	386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	1,180,774	25,261	2.1%	22,025	1.87%	$ (3,236)
40	386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0.0%	0	0.00%	$ -
41	387	OTHER EQUIPMENT	5,308,206	87,088	1.6%	93,367	1.76%	$ 6,279
42	387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	2,309	0.2%	58,834	3.95%	$ 56,525
43								
44		Total Distribution Plant	5,901,774,124	124,811,024	2.1%	102,125,184	1.73%	(22,685,840)
45								
46		**General Plant**						
47	390.1	STRUCTURES AND IMPROVEMENTS	183,834,899	7,154,215	3.9%	7,167,957	3.90%	$ 13,742
48	390.3	CNG Stations	7,022,614	501,969	7.1%	501,969	7.15%	$ -
49	391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,884,524	322,668	5.5%	328,671	5.59%	$ 6,003
50	391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	249,370	27,845	11.2%	23,727	9.51%	$ (4,118)
51	391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	13,631,489	2,016,027	14.8%	2,919,208	21.42%	$ 903,181
52	391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	5,397,504	485,445	9.0%	487,469	9.03%	$ 2,024
53	391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	43,977,025	2,914,581	6.6%	2,925,010	6.65%	$ 10,429
54	392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	4,667,253	322,732	6.9%	297,695	6.38%	$ (25,037)
55	392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	61,236,851	6,376,417	10.4%	6,309,830	10.30%	$ (66,587)
56	392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	7,626,640	570,922	7.5%	517,642	6.79%	$ (53,280)
57	392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	11,059,662	844,799	7.6%	755,894	6.83%	$ (88,905)
58	392.5	TRANSPORTATION EQUIPMENT - TRAILERS	2,944,491	172,826	5.9%	162,009	5.50%	$ (10,817)
59	393	STORES EQUIPMENT	15,838	792	5.0%	791	4.99%	$ (1)
60	394	TOOLS, SHOP AND GARAGE EQUIPMENT	46,258,749	2,359,760	5.1%	2,333,105	5.04%	$ (26,655)
61	395	LABORATORY EQUIPMENT	437,779	22,439	5.1%	22,439	5.13%	$ -
62	396	POWER OPERATED EQUIPMENT	13,798,162	832,914	6.0%	783,748	5.68%	$ (49,166)
63	397	COMMUNICATION EQUIPMENT	2,364,137	264,280	11.2%	324,268	13.72%	$ 59,988
64	398	MISCELLANEOUS EQUIPMENT	2,319,953	85,708	3.7%	61,603	2.66%	$ (24,105)
65	399	OTHER TANGIBLE PROPERTY	0	0	0.0%	0	0.00%	$ -
66	399							
67	399	Total General Plant	412,726,940	25,276,339	6.1%	25,923,034	6.28%	646,695
68	399							
69	399	Total Depreciable Gas Plant	6,365,028,307	150,666,198	2.4%	128,605,642	2.02%	(22,060,556)
70	399							
71	399	Charged to Clearing Accounts	(149,955,945)	(11,744,650)		(11,484,191)		260,459
72	399							
73	399							
74	399	Adjustment to Depreciation Expenses ($'s in Thousands)						(21,800)
75	399	Adjustment to Accumulated Depreciation ($'s in Thousands)						21,800

Note:
1/ Company Exhibit C, Fully Projected, Table 1
2/ Direct Testimony of OCA Witness James Garren

UGI Utilities Inc.
Gas Division
Adjustment to Revise Normalization Period of Rate Case Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Total Rate Case Costs	$ 1,760 [1/]
2		
3	Company Proposed Normalization Period (Years)	1 [1/]
4	OCA Recommended Normalization Period (Years)	2
5		
6	Company Proposed FPFTY Expense	1,760 [1/]
7	OCA Recommended FPFTY Expense	880
8		
9	Adjustment to O&M Expenses	(880)

Note:
[1/] Company Rebuttal Exhibit A, Fully Projected, Schedule D-10

STATEMENT 2SR

Surrebuttal Schedule JLR-7

Contains Confidential Information.

Only this placeholder has been included in the Public version of Statement 2SR.

UGI Utilities Inc.
Gas Division
Adjustment to Employee Activity Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Company Proposed Employee Activity Costs	$ 195 [1/]
2		
3	Adjustment to O&M Expenses	(195)

Note:
[1/] Company response to I&E-RE-14

UGI Utilities Inc.
Gas Division
Adjustment to Vacancy Rate
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Issue resolved in Company's Rebuttal position, as explained OCA Witness Rogers' Surrebuttal Testimony

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 10

UGI Utilities Inc.
Gas Division
Adjustment to Payroll Taxes
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Issue resolved in Company's Rebuttal position, as explained OCA Witness Rogers' Surrebuttal Testimony

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 11

UGI Utilities Inc.
Gas Division
Adjustment to Employee Benefits to Reflect Vacancy Rate Revision
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Issue resolved in Company's Rebuttal position, as explained OCA Witness Rogers' Surrebuttal Testimony

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 12

UGI Utilities Inc.
Gas Division
Adjustment to Advertising Expense - Conservation of Energy
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Issue resolved, as explained OCA Witness Rogers' Surrebuttal Testimony

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 13

UGI Utilities Inc.
Gas Division
Adjustment to Advertising Expense - Other
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	Company Proposed Advertising Expense	
2	for Community Event Sponsorships	$ 191 [1/]
3		
4	Adjustment to O&M Expenses	(191)

Note:
[1/] Company response to I&E-RE-43, Attachment I&E-RE-43

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 14

UGI Utilities Inc.
Gas Division
Adjustment to PUC Assessment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description		Amount	
1	Company Proposed PUC Assessment Charges in FPFT	$	6,006	1/
2				
3	Historical PUC Assessment Charges			
4	2023 Invoice	$	3,523	1/
5	2024 Invoice	$	4,550	1/
6	2025 Invoice	$	4,551	1/
7				
8	Average FY 2023-2025	$	4,208	
9				
10	Adjustment to O&M Expenses		(1,798)	

Note:
1/ Company response to I&E-RE-39, Attachment I&E-RE-39(B-C)

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 15

UGI Utilities Inc.
Gas Division
Adjustment to Residential Collection Expense
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount
1	2025 Residential Collection Expense	$ 6,194 [1/]
2	OCA Recommended Percentage Share to Shareholders	50% [2/]
3		$ 3,097
4		
5	Adjustment to O&M Expenses	(3,097)

Note:
[1/] Company Response to OCA-15-4
[2/] Direct Testimony of OCA Witness Roger Colton

UGI Utilities Inc.
Gas Division
Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description		Amount	
1	Company Rate Base	$	4,337,444	1/
2	Weighted Cost of Debt		2.640%	2/
3	Adjusted Interest Deduction	$	114,509	
4	Interest Deduction Per Company		103,228	3/
5	Adjustment to Synchronize Interest Expense	$	11,281	
6	Effective State Income Tax Rate		7.49%	
7	Adjustment to State Income Taxes	$	(845)	
8	Federal Income Tax Base	$	10,436	
9	Federal Income Tax Rate		21.00%	
10	Adjustment to Federal Income Taxes	$	(2,192)	

Notes:
1/ Surrebuttal Schedule JLR-2, Page 1
2/ Surrebuttal Schedule JLR-17
3/ Company Rebuttal Exhibit A, Fully Projected, Schedule D-33

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 17

UGI Utilities Inc.
Gas Division
Calculation of Rate of Return
For the Twelve Months Ended September 30, 2027

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	51.00%	5.17%	2.64%
2	Total Debt	51.00%		2.64%
3				
4	Common Stock Equity	49.00%	8.80%	4.31%
5				
6	Total	100.00%		6.95%

Source:
Direct Testimony of OCA Witness David Garrett

STATEMENT 2SR

Surrebuttal Schedule JLR-18

Contains Confidential Information.

Only this placeholder has been included in the Public version of Statement 2SR.

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Summary of Rate Base
For the Twelve Months Ended September 30, 2027

Line No.	Description	Amount per Company Filing	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Utility Plant	6,676,559		6,676,559
3	Accumulated Depreciation	(1,736,046)	21,800	(1,714,246)
4	Net Plant in Service	4,940,513	$ 21,800	$ 4,962,313
5				
6	Additions to Net Plant			
7	Working Capital Requirements:			
8	Cash Working Capital	66,348	(2,141)	64,207
9	Materials and Supplies	28,644		28,644
10	Gas Inventory	23,662		23,662
11	Total Additions	118,654	$ (2,141)	$ 116,513
12				
13	Deductions to Net Plant			
14	Customer Deposits	(23,197)		(23,197)
15	Accumulated Deferred Income Taxes	(716,793)		(716,793)
16	Total Deductions	(739,990)	$ -	$ (739,990)
17				
18	Gas Rate Base	4,319,177	$ 19,659	$ 4,338,837

Source: Company Rebuttal Exhibit A, Fully Projected, Schedule C-1

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2027

Line No.	Description	Source	Amount
1	Rate Base per Company Filing	Surrebuttal Schedule JLR-19, Page 1	$ 4,319,177
2			
3	OCA Adjustments:		
4			
5	Adjustment to Cash Working Capital	Surrebuttal Schedule JLR- 21	(2,141)
6	Adjustment to Accumulated Depreciation	Surrebuttal Schedule JLR- 5	21,800
7			
8	Total Ratemaking Adjustments		$ 19,659
9			
10	Adjusted Rate Base per OCA		$ 4,338,837

STATEMENT 2SR

Surrebuttal Schedule JLR-20

Contains Confidential Information.

Only this placeholder has been included in the Public version of Statement 2SR.

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Working Capital for O&M Expense Per Company	$ 56,928	1/
2	Interest Payments Per Company	$ (9,550)	1/
3	Tax Payment Lag Calculations Per Company	$ 4,570	1/
4	Prepaid Expenses Per Company	$ 14,400	1/
5	Cash Working Capital Requirements Per Company	$ 66,348	
6			
7	Revenue Lag Days	57.46	1/
8	O&M Expense Lag Days	27.57	1/
9	Days to mid-point of interest payments	91.25	1/
10			
11	O&M Expenses		
12	O&M Expenses Per Company	$ 695,199	1/
13	OCA Recommended Adjustments to O&M Expenses	$ (12,864)	2/
14	Revised O&M Expenses	$ 682,335	
15	Operating Expenses Per Day	$ 1,869	
16	Net (Lead) Lag Days	29.88	
17	Revised Working Capital for O&M	55,864	
18			
19	Interest Payments		
20	Measure of Value at September 30, 2026	4,319,177	1/
21	OCA Revised Long-term Debt Ratio	45.75%	3/
22	Embedded Cost of Long-term Debt	5.17%	3/
23	Revised Pro forma Interest Expense	102,160	
24	Daily Amount	280	
25	Interest Payment Lag Days	(33.8)	
26	Revised Interest for Working Capital	(9,458)	
27			
28	Tax Payments		
29	Revised Federal Income Tax	46,459	4/
30	Lead (Lag) Payments Days: First Payment	76.00	1/
31	Lead (Lag) Payments Days: Second Payment	17.00	1/
32	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
33	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
34	Revised Weighted Lead (Lag) Dollars	(1,730,610)	
35	Revised Payment Lead (Lag) Days	(37.25)	
36	Net Payment Lead (Lag) Days	20.21	
37	Revised Working Capital Amount	2,572	
38			
39	Revised State Income Tax	10,906	4/
40	Lead (Lag) Payments Days: First Payment	107.00	1/
41	Lead (Lag) Payments Days: Second Payment	17.00	1/
42	Lead (Lag) Payments Days: Third Payment	(75.00)	1/
43	Lead (Lag) Payments Days: Fourth Payment	(167.00)	1/
44	Revised Weighted Lead (Lag) Dollars	(321,738)	
45	Revised Payment Lead (Lag) Days	(29.50)	
46	Net Payment Lead (Lag) Days	27.96	
47	Revised Working Capital Amount	835	
48			
49	PA Property Tax Working Capital Amount	(113)	1/
50	PURTA Working Capital Amount	107	1/
51	Revised Tax Payment Working Captial Amount	3,401	
52			
53	Prepayments		
54	Prepaid Expenses Working Captial Amount	14,400	1/
55			
56	Adjustment to Rate Base	(2,141)	

Note:
1/ Company Rebuttal Exhibit A, FPFTY, Schedule C-4
2/ Surrebuttal Schedule JLR-20
3/ Surrebuttal Schedule JLR-23
4/ Surrebuttal Schedule JLR-18

Docket No. R-2025-3059523
Surrebuttal Schedule JLR- 22

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2027
($ in Thousands)

Line No.	Description	Amount	
1	Company Rate Base	$ 4,338,837	1/
2	Weighted Cost of Debt	2.370%	2/
3	Adjusted Interest Deduction	$ 102,830	
4	Interest Deduction Per Company	103,228	3/
5	Adjustment to Synchronize Interest Expense	$ (398)	
6	Effective State Income Tax Rate	7.49%	
7	Adjustment to State Income Taxes	$ 30	
8	Federal Income Tax Base	$ (368)	
9	Federal Income Tax Rate	21.00%	
10	Adjustment to Federal Income Taxes	$ 77	

Notes:
1/ Surrebuttal Schedule JLR-19, Page 1
2/ Surrebuttal Schedule JLR-23
3/ Company Rebuttal Exhibit A, Fully Projected, Schedule D-33

UGI Utilities Inc.
Gas Division
Alternative ROE/Capital Structure Scenario: Calculation of Rate of Return
For the Twelve Months Ended September 30, 2027

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	45.75%	5.17%	2.37%
2	Total Debt	45.75%		2.37%
3				
4	Common Stock Equity	54.25%	8.50%	4.61%
5				
6	Total	100.00%		6.98%

Source:
Direct Testimony of OCA Witness David Garrett

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division
:

VERIFICATION

I, Jennifer L. Rogers, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: /s/ *Jennifer L. Rogers*
Jennifer L. Rogers

Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	DOCKET NO. R-2025-3059523
v.	:	
UGI UTILITIES, INC.-GAS DIVISION	:	

DIRECT TESTIMONY

BARBARA R. ALEXANDER
BARBARA ALEXANDER CONSULTING LLC

ON BEHALF OF

OFFICE OF CONSUMER ADVOCATE

OCA Statement 5

PUBLIC - REDACTED VERSION

Date Served: April 13,2026

I. INTRODUCTION AND SUMMARY

Q. **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION**.

A. My name is Barbara R. Alexander. I am the sole member manager of Barbara Alexander Consulting LLC. My address is 44 Beech St., Hallowell, ME 04347. I appear in this case as a witness on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. **WHAT IS YOUR BACKGROUND AND EXPERIENCE WITH RESPECT TO THE ISSUES ON WHICH YOU ARE PROVIDING TESTIMONY IN THIS PROCEEDING?**

A. I opened my consulting practice in March 1996, after nearly ten years as the Director of the Consumer Assistance Division of the Maine Public Utilities Commission. While there, I testified as an expert witness on consumer protection, customer service, and low-income issues in rate cases and other investigations before the Commission. My consulting practice is directed to consumer protection, customer service and low-income programs and policies relating to the regulation of the telephone, electric, and gas industries. My practice has included policy issues relating to the adoption of retail energy markets and the regulation of public utility distribution service, particularly relating to reliability of service, rate programs, customer service performance, as well as default service programs and policies. I have appeared in over 30 U.S. and Canadian jurisdictions as an expert witness on behalf of state utility consumer advocates and national and state non-profit consumer organizations.

I am a graduate of the University of Michigan (B.A. 1968) and the University of Maine School of Law (J.D. 1976).

I have appeared before the Pennsylvania Public Utility Commission (PUC or Commission) many times on behalf of the OCA. I filed testimony on consumer education, consumer protection, supplier licensing, customer enrollment, default service, and Code of Conduct issues for the OCA in the Commission's electric restructuring proceedings in 1997 and 1998, as well in all in the natural gas restructuring cases beginning in 1999. With respect to issues relating to retail market competition policies, I have filed testimony on behalf of the OCA on policies that should govern the planning and acquisition of Default Service for residential customers and on proposals to adopt Purchase of Receivables (POR) programs, Customer Referral Programs, and other "retail market enhancement" programs for electric and natural gas utilities. I have provided testimony submitted on behalf of the OCA on customer service, consumer protection and low-income program issues associated with recent electric and natural gas distribution company mergers and base rate cases for electric utilities, water and sewer utilities, and natural gas utilities, including In Re Application of UGI Utilities, Inc., UGI Utilities Newco, Inc., and Southern Union Co., Docket Nos. A-120011F2000, A-125146, A-125146F5000 (June 2006), Petition of UGI Utilities, Inc.—Gas Division for Approval to Voluntarily Implement a Purchase of Receivables Program and Merchant Function Charge and of a Potential Affiliated Interest Agreement Between UGI Utilities, Inc.—Gas Division And Affiliated Entities, Docket No. P-2009-2145498 (April and May 2010), and Petition of UGI Utilities, Inc.—Electric Division for Approval of a Default Service Plan and Retail Market Enhancement Programs for 2014-2017, Docket Nos. P-2013-235703 (June 2013). A complete identification of my relevant proceedings attached as my C.V. as Exhibit BA-1.

Q. **DID YOU TESTIFY ON BEHALF OF THE OCA IN UGI-GAS' MOST RECENT BASE RATE CASE?**

A. Yes. I submitted Direct Testimony (Public and Confidential) in Docket No. 2024-3052716 on April 18, 2025, and Surrebuttal Testimony on May 30, 2025. I will discuss the settlement adopted in that base rate case in more detail below. The Commission adopted the proposed settlement in its Order entered September 11, 2025.

Q. **PLEASE SUMMARIZE THE UGI UTILITIES, INC.-GAS DIVISION (UGI-GAS) PROPOSAL TO INCREASE RATES IN THIS PROCEEDING.**

A. UGI-Gas provides natural gas distribution service to approximately 706,000 residential, commercial, and industrial customers in portions of 46 counties across Pennsylvania. On January 28, 2026, UGI Utilities, Inc. – Gas Division (UGI-Gas or the Company) filed Supplement No. 63 to UGI Gas Tariff – PA. P.U.C. Nos. 7 and 7S with the Commission. The Company proposes to increase rates to produce additional overall revenues of $99.368 million per year, an 8.05% increase in overall distribution revenue requirement. Under the Company's proposal, the total bill for a residential customer purchasing 68.7 cubic feet (CCF) per month would increase by $9.91 from $113.64 to $123.55, or by approximately 8.7%. The Company has proposed increasing the monthly residential customer charge from $16.25 to $23, or by 41.5%. The Company proposes a return on equity of 10.75% resulting in an overall rate of return of 8.20%, in conjunction with an equity-rich capital structure of 54% equity and 46% debt. Additionally, the filing requests approval of a continued weather normalization adjustment (WNA).

Q. **HOW DOES UGI-GAS JUSTIFY ITS RATE INCREASE IN THIS PROCEEDING?**

A. The President of UGI Utilities, the corporate owner of UGI-Electric and UGI-Gas, Mr.

Hans G. Bell states, "UGI Gas continues to make substantial distribution system investments that are necessary to: (1) continue the accelerated replacement of aging gas plant infrastructure; (2) upgrade and improve system segments and modernize facilities; (3) serve new residential and commercial customers, including natural gas conversions; (4) install and upgrade supporting information technology systems; and, most importantly, (5) ensure the safety of the Company's employees, customers, the communities it serves, and its distribution system. Moving forward, these system improvements and investments will require the Company to continue its efforts to attract, recruit, train, and retain those professional, technical, and field-qualified personnel and resources necessary to implement, operate, and maintain those investments, and to attract capital at a reasonable cost. These investments are all necessary to grow and continue to maintain a safe and reliable distribution system and provide quality customer service."[1] Mr. Bell links the proposed investments and rate increase to, among other objectives, "system reliability, safety, and customer service performance."[2] In his attached qualifications, Mr. Bell asserts that he has "[c]onsistently led team to deliver on key metrics including safety, reliability, customer service, and financial objectives."[3] Unlike the last base rate case filing that was filed in December 2024 and litigated and resolved in 2025, UGI-Gas does not seek an upward adjustment in its equity return for management performance.

Q. **WHAT ISSUES WILL YOU ADDRESS IN YOUR TESTIMONY?**

A. I will address the following issues in this proceeding:

[1] UGI Gas Statement No. 1, page 6, lines 1-12.
[2] Ibid., page 7, lines 6-7.
[3] UGI Gas Exhibit HGB-1.

- The Company's compliance with certain settlement conditions ordered in the 2025 rate case.
- Additional customer service performance and compliance issues that should be adopted in this rate case.
- I will address the significantly higher charges appearing on UGI Gas residential bills on behalf of Natural Gas Suppliers (NGS) and recommend additional consumer communications and bill content to assist customers in understanding the impact of these higher charges on their bills.
- Additional service quality and operational performance metrics and promises that UGI Gas Witness Walter identifies and that should be adopted in this rate case.

Q. **IS YOUR TESTIMONY EXCLUSIVE ON THESE ISSUES?**

A. No. While I am the primary witness on customer service and consumer protection policies and programs, my testimony supplements and contributes to the overall recommendations of other OCA witnesses.

Q. **WILL YOU PROPOSE CHANGES TO THE REVENUE REQUIREMENT OR RATES PROPOSED BY UGI-GAS?**

A. Not directly. My testimony concerning customer service and reliability of service performance is intended to provide context on the reasonableness of UGI-Gas' proposed revenue requirement, as well as the adjustments made by other OCA witnesses.

Q. **DO YOU HAVE EXHIBITS ATTACHED TO YOUR TESTIMONY?**

A. Yes. I attach the following Exhibits:

- Exhibit BA-1: C.V. of Barbara R. Alexander
- Exhibit BA-2: UGI Gas Response to OCA-3-1(a) with 2025 average calculations

- Exhibit BA-3: UGI's proposed field operations training materials (CONFIDENTIAL)
- Exhibit BA-4: UGI Gas Response to OCA-6-12
- Exhibit BA-5: UGI Gas Response to OCA-3-10.2.
- Exhibit BA-6: UGI Gas Response to OCA-3-8.
- Exhibit BA-7: UGI Gas Response to CAUSE PA-5-10.

Q. **AS AN OVERALL INTRODUCTION TO YOUR RECOMMENDATIONS, PLEASE COMMENT ON UGI-GAS' JUSTIFICATION FOR ITS RATE INCREASE IN THIS PROCEEDING.**

A. My primary concern is that is that no UGI Gas witness describes or references the Company's customer service performance or compliance related issues as measured and reported to the Commission or its performance in relationship to other Pennsylvania natural gas utilities with respect to the operation of its customer call center, complaints, Chapter 56 compliance, or customer satisfaction measurements. The lack of any presentation or reference to the key customer service performance indicators that are routinely relied upon and published by the Commission in its Consumer Activities Report and Evaluation and Customer Service Performance Reports is a troubling omission. Nor did Mr. Bell or any corporate manager for customer service operations describe how the Company provides these vital services to its captive customers. My concern is also a reflection of UGI's lack of recognition or discussion about the ongoing implementation of numerous consumer protection and service quality conditions ordered in the last rate case.

Q. PLEASE COMMENT ON THE INTERNAL OPERATIONAL AND SAFETY RELATED OBJECTIVES IDENTIFIED IN UGI WITNESS JILL WALTER'S TESTIMONY.

A. Ms. Walter identifies a wide range of internal objectives for operational service quality, employee safety, and environmental goals in her Direct Testimony (UGI Statement No. 3). None of these objectives or internal goals reflect customer service or affordability issues that I and other OCA Witnesses address in our testimony. Nor does Ms. Walter link these objectives and goals to firm commitments or conditions to any increase in rates. Nor does she explain why these objectives and goals should be required of the Company whether or not any rate increase is granted in this proceeding.

Q. **WHAT IS THE CONNECTION BETWEEN YOUR DISCUSSION OF SERVICE QUALITY AND CUSTOMER SERVICE PERFORMANCE AND THE RATE INCREASE PROPOSED BY UGI?**

A. A public utility in Pennsylvania is statutorily obligated to provide adequate and reasonable service to its customers. A public utility must justify its rates based on, among other things, its ability to perform its essential quality of service and customer service functions at an adequate and reasonable performance level. Accordingly, where a public utility is seeking a rate increase – especially a significant one – it is appropriate to review the performance of that utility and to compare such performance to other Pennsylvania utilities. Therefore, my evaluation of UGI's customer service and consumer protection policies is directly related to the Commission's consideration of the Company's general rate increase. In effect, it is part of the consideration by the Commission to determine whether UGI Gas is

upholding its end of the bargain. My focus on these issues and response to my findings reflect the statutory guidelines of Section 523 of the Public Utility Code governing public utility rate cases in which the Commission must evaluate the "efficiency, effectiveness, and adequacy of service."[4]

Q. **PLEASE SUMMARIZE YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS.**

A. I recommend the following conclusions and recommendations that should be taken into account when considering reasonable and affordable rates and earnings mechanisms for UGI Gas. My recommendations support the overall recommendations of other OCA witnesses to either reject the Company's rate increase, or substantially lower any rate increase in this proceeding. The following summarize my recommendations that are documented and presented in more detail throughout my testimony:

- UGI Gas has not completed many of the agreed upon service quality and customer service conditions ordered in the last rate case and, at a minimum, the Commission should monitor and ensure compliance with those conditions prior to considering any further rate increases.
- UGI has adopted internal performance and compliance related performance indicators for its third party call contractors that I support. The Commission should require UGI to implement and report on these performance indicators to avoid any deterioration of service and to properly monitor third party call centers.

[4] 66 Pa. C.S. § 523(a).

- UGI should adopt additional and more targeted customer communications to assist customers in ensuring affordability for basic natural gas service due to high NGS charges that appear on the customer bill that UGI collects under threat of termination of service. In addition, UGI's bill should be reformed to more directly link the presentation of NGS charges with the PTC.

II. EVALUATION OF UGI GAS' COMPLIANCE WITH THE CUSTOMER SERVICE AND CONSUMER PROTECTION REQUIREMENTS OF THE 2025 BASE RATE CASE ORDER.

Q. **PLEASE IDENTIFY THE COMMITMENTS MADE IN THE APPROVED SETTLEMENT IN UGI GAS' MOST RECENT BASE RATE CASE THAT YOU WILL REVIEW IN YOUR TESTIMONY.**

A. I will review compliance with the following provisions of the settlement provisions approved and ordered in UGI's most recent base rate case filed in early 2025 and litigated and included in the final order issued in September 2025:

1) "UGI Gas will work to maintain its call center performance at levels consistent with its 2024 performance as reported to the Commission. In working to maintain a quality level of service, UGI Gas will meet with the Parties to discuss areas of challenge and its plans to improve its service levels."[5]

2) "UGI Gas will provide its annual performance reports to the USAC when its annual

[5] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2024-3052716 (Aug. 8, 2025) Recommended Decision, 126 (summarizing Joint Petition for Settlement ¶ 82) (*R.D. 2025)*.

reporting data is compiled and submitted to the Commission. UGI Gas is committed to continuously reviewing and attempting to improve the level of service provided to its customers."[6]

3) "UGI Gas will develop additional training materials for its field representatives by April 1, 2026, including making personal contact with customers prior to termination, and will incorporate these materials into the training of its field representatives."[7]

4) "As recommended by OCA, UGI Gas will also provide for two modifications of its website: It will disclose that products such as HomeServe are optional (and that failing to pay for such will not result in termination of utility service); and it will remove the term "affordable" from those types of non-required products."[8]

5) "OCA recommended an implementation of a root cause analysis of customer disputes, and UGI Gas has agreed to this implementation under the Settlement. UGI Gas will categorize, track, review and remediate Justified Complaints and Verified Infractions issued by the Commission's Bureau of Consumer Services."[9] "Once the process is formalized and implemented, the Company will conduct a monthly review of Justified Complaints and Verified Infractions and the resulting RCAs' and ACEs' causal factors and corrective actions. UGI Gas will provide a report to CAUSE-PA, CEO, I&E, the OCA, and the OSBA annually, describing its progress

[6] *Id.* (summarizing Joint Petition for Settlement ¶ 83).
[7] *Id.* at 127 (summarizing Joint Petition for Settlement ¶ 84).
[8] *Id.* (summarizing Joint Petition for Settlement ¶ 85).
[9] *Id.* (summarizing Joint Petition for Settlement ¶ 86).

and the results of its review and implementation of the RCA and/or ACE process, with the first report being provided on or before October 1, 2026, until a final Commission order is entered in UGI Gas' next base rate proceeding."[10]

6) "By April 1, 2026, UGI Gas will develop a written communication to confirm the terms of modified payment agreements upon conclusion of a customer's verbal agreement."[11]

7) The Company will review its existing WNA customer communications with the intent to further enhance customer communication materials in support of customer education related to the WNA. The review will consult the interested parties and will conclude by December 31, 2025.[12]

8) "The Company will move the Price to Compare ("PTC") from the back of the bill to the front of the bill. This update will be implemented on or before April 1, 2026."[13]

9) "The Company will provide online payment options for Apple Pay and Venmo, which will be implemented by end of September 30, 2025. Google Pay, PayPal, PayPal Credit, and Amazon Pay will be implemented on a phased-in approach to allow time for proper testing of each option."[14]

10) "By no later than April 1, 2026, UGI Gas will begin covering the transaction costs

[10] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2024-3052716 (Aug. 8, 2025) Joint Petition for Settlement ¶ 86).
[11] *R.D. 2025* at 127 (summarizing Joint Petition for Settlement ¶ 87).
[12] *See* Joint Petition for Settlement ¶ 58.
[13] *Id.* at ¶ 66.
[14] *Id.* at ¶ 68.

for payments made in cash by customers through the Company's current partnerships that allow customers to pay in cash at authorized retail establishments."[15]

Q. **AS A RESULT OF THE FILING OF THIS BASE RATE CASE FOUR MONTHS AFTER THE FINAL ORDER IN ITS PRIOR BASE RATE CASE, CAN YOU PROVIDE ANY CONCLUSIVE OPINION ABOUT HOW UGI GAS HAS COMPLIED WITH THESE SETTLEMENT COMMITMENTS APPROVED IN SEPTEMBER 2025?**

A. No. UGI Gas filed a base rate case in January 2026, prior to many of the April 1, 2026 or later deadlines for the commitments negotiated in its prior rate case. The Company provided no testimony or evidence in this pending base rate case filing that demonstrates compliance with these customer service and consumer protection commitments with the exception of a reference to the ongoing progress for one of these commitments.[16] I will evaluate the Company's compliance to date in my testimony based on discovery responses received to date.

Q. **HAS UGI GAS MAINTAINED ITS 2024 PERFORMANCE FOR ITS CUSTOMER CALL CENTER?**

A. UGI Gas' call center performance in 2024 was reported to the Commission as achieving an annual percentage of calls answered within 30 seconds of 86% and an annual abandonment rate of 4%.[17] The call answering percentage included IVR calls and, as a result, does not measure the answering performance of those customers who entered the

[15] *Id.* at ¶ 69.
[16] *See* UGI Statement No. 12, Brian Meilinger on the ongoing development of revised WNA communications.
[17] https://www.puc.pa.gov/media/3762/2024-customer-service-performance-report-final.pdf at 5, 7.

IVR and then selected to speak to a customer service representative.[18] While the overall performance reflects a significant improvement since 2022, a result that is typical of other Pennsylvania natural gas utilities, UGI's performance has not improved as much as other utilities. For example, the 4% abandonment rate is the highest of the Pennsylvania gas utilities and Columbia Gas, NFG, and PGW reported a 2% abandonment rate.[19] In addition, most other gas utilities reported a higher percentage of answering calls within 30 seconds than UGI.[20]

UGI has increased its annual average abandonment rate from 4% in 2024 to 4.7% in 2025 and equaled the 2024 86% call answering metric. I attach the monthly results from January 2023 through January 2026 with my calculation of the average 2025 results as Exhibit BA-2.[21] I am particularly concerned that the monthly abandonment rate reflects a wide range of customer call performance experience, reflecting a significantly deterioration with abandonment rates of 6.14% in February, 9.57% in October, and 7.51% in November 2025. Customers also experienced call answering percentages of below 80% during these same months. As a result, it is fair to state that the Company has not complied with the "soft" obligation to continue its 2024 performance results, particularly with respect to the annual abandonment rate, and that customers experienced a lower level of performance in several months.

Q. **HAS UGI GAS COMPLIED WITH ITS REPORTING REQUIREMENTS TO THE USAC?**

[18] *Id.* at 7.
[19] *Id.* at 5.
[20] *Id*. at 7.
[21] UGI Response to OCA-3-1(a).

A. Not yet. The Company did not yet provide the reporting requirements to the USAC at either the December 2025 or the February 24, 2026 USAC meeting. It is my understanding that the Company reviewed the status of the Company's progress on the 2025 base rate Settlement commitments at the February 24, 2026 USAC meeting. I would anticipate that the annual data for 2025 would be presented to the USAC at a later 2026 meeting.

Q. **PLEASE DISCUSS UGI GAS' COMPLIANCE WITH REVISED TRAINING MATERIALS FOR ITS FIELD PERSONNEL TO ENSURE COMPLIANCE WITH THE OBLIGATION TO ATTEMPT PERSONAL CONTACT PRIOR TO TERMINATION OF SERVICE.**

A. The Company submitted proposed revised training materials to the parties for comment in February 2026. In response to numerous comments from OCA and other parties, UGI revised these materials and submitted them to the parties in late March 2026. I attach the revised training materials provided to the parties in late March 2026 as Exhibit BA-3 (CONFIDENTIAL[22]). In reviewing the proposed training materials that I presume have now been implemented as a result of the obligation to implement changes by April 1, 2026, I have a number of outstanding concerns that need additional reforms: [**BEGIN CONFIDENTIAL]**

[redacted]

[22] The basis for the Confidential label is due to the internal UGI operations information included in these materials.

[redacted]

[redacted] **[END CONFIDENTIAL]**

As a result, I do not consider the materials and their format developed to date to be a sufficient response to the settlement condition.

Q. **HAS UGI MADE THE REQUIRED MODIFICATIONS TO ITS WEBSITE WITH REGARD TO ITS PROMOTION OF NON-BASIC SERVICES BY HOMESERVE?**

A. Yes.[23]

Q. **HAS UGI GAS IMPLEMENTED ITS COMMITMENT TO A ROOT CAUSE ANALYSIS FOR CERTAIN COMPLAINTS?**

A. I am not yet able to provide any definitive information to conclude that the Company has taken the appropriate steps to implement this requirement, but I acknowledge that UGI is developing internal tracking of key data to allow for a subsequent RCA analysis. The settlement required UGI Gas to categorize, track, review and remediate Justified Complaints and Verified Infractions issued by the Commission's Bureau of Consumer Services. The Company has not yet completed this commitment. Rather, according to responses to discovery, the Company "is working to document and implement a formalized process using Root Cause Analysis (RCA) or Apparent Cause Evaluation (ACE), as circumstances warrant."[24] Several internal processes to update the categorization and coding of formal and informal complaint records with system enhancements are in process, as well as standardization of tracking employee errors through justified complaints.[25] "As a result of these efforts, the Company has identified some scenarios that warrant further analysis and is now positioned to begin formalizing the RCA and ACE process."[26] The Company states that an RCA report to the parties is on track to be provided by October 1,

[23] https://ugi.com/optional-home-repair-plans/
[24] UGI Response to OCA-6-12.
[25] *Id.*
[26] *Id.*

2026.[27] I attach the Company's complete response to a request to describe progress to date as Exhibit BA-4 (UGI Response to OCA-6-12).

Q. **HAS UGI DEVELOPED A WRITTEN CONFIRMATION OF PAYMENT ARRANGEMENT?**

A. Yes. I attach the written confirmation of a payment arrangement provided in UGI's response to OCA-3-10.2 as Exhibit BA-5. However, this document as presented is defective in that it does not include any notice of customer rights and should be revised to do so, including the right to a dispute the terms of the payment arrangement with UGI and, if not satisfied, how to file an informal complaint to the Commission.

Q. **HAS UGI GAS REVISED AND IMPLEMENTED ITS CUSTOMER COMMUNICATIONS AND TRAINING MATERIALS ON THE WEATHERIZATION NORMALIZATION ADJUSTMENT?**

A. UGI has solicited the parties' comments on revised customer communications relating to the WNA, including its website explanation and communications to customers who seek more information on their WNA adjustment. The website revisions were implemented in late 2025, including a new FAQ page. The revised customer letter will be available in "Fiscal Year 2026."[28] Training materials for customer service representatives will be implemented with the revised customer letter.[29] Therefore, I have not reviewed the training materials or the final version of the customer letter. A significant omission in these communications is a presentation of the historical incremental charges and/or credits imposed on customers as a result of this program. UGI Gas has refused to include such

[27] *Id.*
[28] UGI Response to OCA-6-3.
[29] UGI Response to OCA-7-18.

information in its customer education materials. The WNA is complicated in that it changes the customer's distribution portion of the UGI Gas bill with a formula that is highly technical and based on the customer's usage and weather based on a s15-year historical experience. However, the educational materials do not inform customers about the ultimate result of its complicated formulas, that is, the increased charges from WNA have far outweighed any balanced approach in the form of lower charges or credits since the onset of this "pilot" in November 2022. OCA Witness Michael Deupree will testify on whether this method of changing customer rates for UGI Gas' regulated distribution service outside of base rate cases should continue, particularly since UGI Gas has filed frequent rate cases that allow for a reset of its distribution rates to reflect actual costs and expenses that are impacted, if at all, by weather.

Q. **HAS THE UGI GAS CUSTOMER BILL MOVED THE PRESENTATION OF THE PRICE TO COMPARE TO THE FRONT OF THE BILL?**

A. Yes. I attach UGI Gas' response to OCA-3-8 that provides a bill for an RT customer being served by a Natural Gas Supplier (NGS) as Exhibit BA-6. The price to compare is stated as $0.69874/CCF and the customer's supplier on this bill is charging $1.57020/CCF.[30] While this presentation does comply with the settlement's requirement about the placement of the PTC on the customer bill, I note that the terms used to describe the PTC as the "natural gas Price to Compare" is not the same term used to label the supplier's "commodity charge." These terms should be the same so that the customer can more directly relate the PTC to the NGS's charges on the customer bill. Either the PTC should

[30] UGI Attachment OCA-3-8 at 1.

be labeled as the UGI Gas "commodity charge" or both NGS and PTC charges should be labeled as "natural gas supply charge." I also have additional testimony below with respect to the significant overcharging by NGSs to UGI's residential customers.

Q. **HAS UGI GAS IMPLEMENTED THE ALTERNATIVE METHODS FOR BILL PAYMENT BY THE SEPTEMBER 2025 DATE?**

A. No. The public website does not mention the ability to pay via Venmo or ApplePay. UGI Gas states that Google Pay, Pay Pal, and Pay Pal Credit methods are deployed in the Company's "test environment" and that the Company is "completing User Acceptance Testing for these payment methods."[31] Furthermore, Amazon Pay will not be offered. [32] As a result, it is not clear if the required date for implementation was met for all these new payment options. However, I acknowledge that ongoing implementation is underway.

Q. **HAS THE COMPANY IMPLEMENTED ITS COMMITMENT TO ELIMINATE PAYMENT FEES?**

A. Yes. The Company's website states that customers can pay through the customer's checking account or by credit or debit card without fee. At this time there is no mention of alternative payment options such as Venmo and ApplePay on the public facing website.

Q. **AS A RESULT OF YOUR REVIEW OF UGI'S COMPLIANCE WITH THE ABOVE LISTED CUSTOMER SERVICE AND CONSUMER PROTECTION SETTLEMENT PROVISIONS IN ITS 2025 BASE RATE CASE, WHAT DO YOU RECOMMEND?**

[31] UGI Response to OCA-6-9.
[32] *Id.*

A. Based on my analysis to date, the Commission should find that the Company has not complied with its intent to meet the 2024 call center performance standards, that the revised training materials for field representatives are defective as I have documented, that the Root Cause Analysis has not been completed, that the confirmation of payment arrangement communication is defective, that the bill presentation of the PTC should be reformed to use the same terms as reflected in the NGS charges, that the WNA communications should be reformed to include an historical presentation of incremental charges and credits, and that the Company is still in the process of implementing its promised alternative bill payment options by the promised deadline. My findings support the position of other OCA witnesses that reject the Company's proposed revenue requirement because it is unreasonable for the Company to ignore these commitments while seeking a significant new rate increase. If there is any rate increase ordered in this proceeding, I recommend that the Commission require a complete documentation of the prior conditions I have identified in my testimony with my required reforms prior to any implementation of increased rates.

III. ADDITIONAL CUSTOMER SERVICE PERFORMANCE AND CONSUMER PROTECTION CONDITIONS SHOULD BE REQUIRED

Q. **PLEASE DESCRIBE HOW UGI GAS PROVIDES CUSTOMER CALL CENTER SERVICES TO PENNSYLVANIA CUSTOMERS.**

A. The call centers handle calls from UGI-Electric and UGI-Gas and the results do not distinguish between the two operating companies.[33] The call centers are the only means by

[33] UGI Gas Response to OCA-3-1(a).

which customers can speak to an individual about their service needs, file a complaint, ask for a payment plan, or otherwise engage in negotiations since there is no in-person office available to UGI-Gas or UGI-Electric customers.[34]

Q. **HOW ARE THE CALL CENTER SERVICES STAFFED?**

A. The Company operates a virtual call center with 107 Call Service Representatives (CSRs) staffed to work remotely.[35] In addition, there are currently two third party call centers providing additional call center support to the Company with one located in Arkansas staffed with approximately 30 call center reps, 2 supervisors, 1 quality assurance, and 1 trainer representative.[36] The second third party call center is located in Texas and staffed with 1 supervisor and 2 employees supporting quality assurance and training needs.[37]

Q. **DOES UGI HAVE INTERNAL CALL CENTER PERFORMANCE STANDARDS AND METRICS?**

A. Yes. According to UGI, [**BEGIN CONFIDENTIAL**] [redacted] **END CONFIDENTIAL**] UGI has [**BEGIN CONFIDENTIAL**] [redacted]

[34] UGI Gas Response to OCA-3-5.
[35] UGI Gas Response to OCA-3-4.
[36] *Id.*
[37] *Id.*
[38] [redacted]

[redacted], [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. **WHAT IS YOUR RECOMMENDATION WITH RESPECT TO UGI'S OVERSIGHT AND COMPLIANCE MONITORING OF ITS CALL CENTERS?**

A. I find the overall contractual provisions and specific efforts to track compliance with Pennsylvania consumer protection regulations and the Company's training documents are reasonable. In comparing this specific level of oversight with other Pennsylvania utilities with third party call centers, the UGI Gas contracts are a model I support. With regard to this base rate case, I recommend that the current internal UGI performance metrics for its call centers that I have identified be formally adopted and required by the Commission to ensure that UGI Gas' internal performance requirements are maintained and not allowed to deteriorate.

[redacted]

IV. UGI GAS SHOULD TAKE ADDITIONAL CUSTOMER COMMUNICATION INITIATIVES TO RESPOND TO THE HIGHER NGS CHARGES COMPARED TO THE PTC THAT UGI GAS BILLS AND COLLECTS FROM RESIDENTIAL CUSTOMERS

Q. HAS UGI GAS CALCULATED WHAT RESIDENTIAL CUSTOMERS PAY FOR ESSENTIAL NATURAL GAS SUPPLY SERVICE WHEN SERVED BY AN NGS COMPARED TO WHAT THE CUSTOMER WOULD HAVE PAID WITH THE PRICE TO COMPARE?

A. Yes. From January 2025 through December 2025, Residential Transportation (RT) customers paid $17,044,378.67 more to their NGS compared to the PTC.[41] 76.7% of these customers paid more than the PTC.[42] I attach the UGI compilation of this data as Exhibit BA-7 (UGI Gas Response to CAUSE PA-5-10).

Q. DOES UGI GAS PROVIDE ANY CUSTOMER SPECIFIC COMMUNICATIONS ABOUT COMPARING THEIR NGS CHARGES TO THE PTC?

A. No.[43] The Company's website provides standardized information about retail choice[44] and, as described above, does include the PTC on customer bills but using terms that are not those used to label the NGS "commodity charge" on the bill. The Company also has a box on its "UGI Connections" bill inserts that advertises the right to choose an alternative

[41] UGI Gas Response to CAUSE PA-5-10, attachment.
[42] *Id.*
[43] UGI Gas Response to OCA-11-5.
[44] https://www.ugi.com/choice/supplier-information/

supplier and specifically notes "customers may save money by shopping for a supplier."[45]

Q. **HAS UGI GAS DOCUMENTED THE INCREMENTAL COSTS TO BILL AND COLLECT NGS CHARGES THAT CREATE HIGHER BILLS COMPARED TO THE PTC?**

A. No.

Q. **WHY SHOULD THIS BASE RATE PROCEEDING ADDRESS THIS ISSUE?**

A. UGI should prioritize the adverse impact on customer bills due to high NGS charges to address affordability for basic and essential natural gas service. UGI purchases the NGS receivables and bills and collects the NGS charges as if they were regulated and subject to the Commission's regulations on disconnections, payment plans, late fees, and other collection actions. Therefore, the results of higher bills charged to RT customers flows through base rates for distribution service and the adverse impact on customers paying significantly more for basic natural gas supply service is directly reflected in UGI's collection activities in terms of customer calls, payment plans, premise visits to disconnect service, all of which results in higher costs imposed on all residential customers. UGI has an obligation and the discretion to address this issue now.

Q. **WHAT DO YOU RECOMMEND TO BETTER INFORM CUSTOMERS ABOUT THE CLEAR EVIDENCE THAT CUSTOMERS ARE LIKELY TO PAY MORE TO AN NGS COMPARED TO THE PTC?**

[45] UGI Gas Response to OCA-11-7, attachment.

A. First, I recommend that UGI eliminate their prominent statement in the bill insert materials that retail choice may have the potential to "save" since that is not the actual experience for the vast majority of residential customers that choose an NGS. The Company should include information in its FAQs and customer bill inserts about the right to choose and explain that the risk of higher prices is documented and how to avoid higher prices and bills. UGI should explain how to shop and compare NGS prices during the entire term of the contracts and alert customers to the potential for a change in the NGS price after any initial promotional price and how NGS variable rates can reflect volatile changes in the wholesale market. This fact-based content is justified by the actual results of residential customer shopping as documented both historically and most recently in UGI's analysis provided in this proceeding. Second, I recommend that UGI develop targeted communication to customers with NGS charges that increase significantly over the PTC to alert them to compare that price to the PTC and include a calculation that documents this difference in the customer's recent bill(s).

Q. **DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

A. Yes.

Exh. BA-1
Barbara Alexander CV 12-2025

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PRIOR Clients:

AARP
Pennsylvania Office of Consumer Advocate
Public Counsel Unit, Attorney General, Washington
Arkansas Attorney General
The Public Utility Project of New York
Ohio Office of Consumer Counsel
District of Columbia Office of People's Counsel
Delaware Division of Public Advocate
Maryland Office of People's Counsel
TURN (The Utility Reform Network), California

Areas of Expertise:

- Default Service, Consumer Protection, Service Quality, and Universal Service policies and programs associated with the alternative rate plans and mergers;
- Consumer Protection and Service Quality policies and programs associated with the regulation of competitive energy and telecommunications providers;
- The regulatory policies associated with the regulation of Credit, Collection, Consumer Protection, Low Income, and Service Quality programs and policies for public utilities;
- Customer Education and Rate design and pricing policies applicable to residential customers; and
- Advanced Metering Infrastructure and Grid Modernization costs and benefits, time-based pricing proposals, and performance standards.

Prior Employment

DIRECTOR

1986-96

Consumer Assistance Division

Maine Public Utilities Commission *Augusta, Maine*

One of five division directors appointed by a three-member regulatory commission and part of commission management team. Direct supervision of 10 employees, oversight of public utility consumer complaint function, appearance as an expert witness on customer services, consumer protection, service quality and low income policy issues before the PUC. Chair, NARUC Staff Subcommittee on Consumer Affairs.

SUPERINTENDENT

1979-83

Bureau of Consumer Credit Protection
Department of Professional and Financial Regulation *Augusta, Maine*

Director of an independent regulatory agency charged with the implementation of Maine Consumer Credit Code and Truth in Lending Act. Investigations and audits of financial institutions and retail creditors, enforcement activities, testimony before Maine Legislature and U.S. Congress.

Education

JURIS DOCTOR

1973-76

University of Maine School of Law *Portland, Maine*

Admitted to the Bar of the State of Maine, September 1976. Currently registered as "inactive."

B.A. (WITH DISTINCTION) IN POLITICAL SCIENCE 1964-68
University of Michigan *Ann Arbor, Michigan*

Boards and Commissions

Councilor, Winthrop (ME) City Council 2020-2022

Member, Board of Trustees, University of Maine System May 2022 to present
(Nominated by Governor and Confirmed by Maine Legislature)

Publications and Testimony

"How to Construct a Service Quality Index in Performance-Based Ratemaking", The Electricity Journal, April, 1996

"The Consumer Protection Agenda in the Electric Restructuring Debate", William A. Spratley & Associates, May, 1996

Direct Testimony on behalf of the Telecommunications Workers Union, Telecom Public Notice 96-8, Price Cap Regulation and Related Issues, Canadian Radio-Television and Telecommunications Commission, September, 1996. [Analysis of and recommendations concerning the need to regulate service quality in move to price cap regulation]

Direct Testimony on behalf of Public Counsel Section, Office of Attorney General, Docket No. UE-960195, Application by Puget Sound Power and Light Co. And Washington Natural Gas Co. For Approval of Merger), Washington Utilities and Transportation Commission, September 1996 [Need for and design of a Service Quality Index for both electric and gas business

units as part of a multi-year rate plan]

Consumer Protection Proposals for Retail Electric Competition: Model Legislation and Regulations", Regulatory Assistance Project, Gardiner, ME, October 1996

Direct and Rebuttal Testimony on behalf of the Citizens Utility Board (IL), Docket 96-0178, Illinois Commerce Commission, CUB v. Illinois Bell Telephone Co., January 22, 1997; July 1997. [Analysis of recent service quality performance and recommendations for changes in current service quality performance plan]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate, Restructuring Proceedings before the Pennsylvania PUC: PECO Energy; Pennsylvania Power and Light Co.; GPU Energy; Duquesne Light Co.; West Penn Power Co., UGI-Electric, Pennsylvania Power Co., Pike County Light and Power Co. (1997 and 1998). [Specific consumer protection, consumer education and supplier-utility-customer interactions necessary for move to electric restructuring]

"The Transition to Local Telecommunications Competition: A New Challenge for Consumer Protection", Public Counsel Section, Washington Attorney General, October 1997. [Reprinted in part in NRRI Quarterly Bulletin, Vol. 19, N0.1, Spring, 1998]

Direct and Surrebuttal Testimony on behalf of the New Jersey Division of Ratepayer Advocate, Restructuring Proceedings before the New Jersey Board of Public Utilities: Public Service Electric and Gas, Jersey Central (GPU), Rockland Electric Co., Atlantic Electric Co., March-Apri1 1998. [Phase-in and customer enrollment, Code of Conduct, consumer protections associated with the provision of Provider of Last Resort service]

Oppenheim, Gerald (NCLC) and Alexander, Barbara, Model Electricity Consumer Protection Disclosures, A Report to the National Council on Competition and the Electric Industry, April 1998.

Direct and Reply Testimony on behalf of the Maryland Office of People's Counsel, Investigation into Certain Unauthorized Practices (Slamming and Cramming), Case. No. 8776, before the Maryland Public Service Commission, 1998 and 1999.

Direct Testimony on behalf of the Maryland Office of People's Counsel, Universal Service Issues, Case No. 8745, before the Maryland Public Service Commission, November 20, 1998.

"Cramming is the Last Straw: A Proposal to Prevent and Discourage the Use of the Local Telephone Bill to Commit Fraud," NRRI Quarterly Bulletin, Fall. 1998.

Alexander, Barbara, Retail Electric Competition: A Blueprint for Consumer Protection, U.S. Department of Energy, Office of Energy and Renewable Energy, Washington, D.C., October 1998.

Alexander, Barbara, "Consumer Protection Issues in Electric Restructuring for Colorado: A Report to the Colorado Electricity Advisory Panel," on behalf of the Colorado Office of Consumer Counsel, February 1999.

Testimony on Proposed Interim Rules (Consumer Protection, Customer Enrollment, Code of Conduct, Supplier Licensing) on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey BPU, May 1999.

Direct Testimony on behalf of AARP, West Virginia PUC Investigation into Retail Electric Competition (consumer protection, universal service, Code of Conduct), June 15, 1999.

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Direct, Rebuttal, and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Petition of PECO Energy for Approval of Default Service Program for the Period June 1, 2021 through May 31, 2025, Docket No. P-2020-3019290 (June-July 2020),) [Standard Offer Program and low income shopping program for retail market programs]

Direct, Rebuttal, and Surrebuttal Testimony, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Petition of Duquesne Light Co. for Approval of Default Service Program for the Period June 1, 2021 through May 31, 2025, Docket No. P-2020-3019522 (July-September 2020), [Standard Offer Program and low income shopping program for retail market programs]

Direct and Surrebuttal Testimony, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania Public Utility Commission v. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 (water), C-2020-3019348, R-2020-3017970 (wastewater), C-2020-3019349 (July-September 2020) [Base rate case; analysis of customer service and consumer protection programs and policies]

Affidavit of Barbara R. Alexander, Analysis of Washington Gas Light Co. Root Cause Analysis Report, on behalf of the Office of the People's Counsel of the District of Columbia, submitted to the Public Service Commission in Formal Case No. 1142 (October 2020).

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania Public Utility Commission v. Pennsylvania American Water Co, Docket R-2020-3019369, et al., (September-October 2020) [Base rate case; analysis of customer service and consumer protection programs and policies]

Direct and Surrebuttal Testimony, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania Public Utility Commission v. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773, et al. (July-September 2021) [Base rate case; analysis of customer service and consumer protection programs and policies]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc, Docket Nos. R-2021-3027385 et al. (November-December 2021) [Base rate case; analysis of customer service and consumer protection programs and policies]

Direct, Rebuttal, and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Joint Petition of Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania Power Co. and West Penn Power Co. for Approval of their Default Service Programs, Docket Nos. P-2021-3030012 et al. (February, March, and April 2022) [Standard Offer program; retail market policies; Time of Use rate option; low income consumer protections]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania American Water Co., Docket Nos. R-2022-3031672, et al (July and September 2022) [Base rate case: analysis of customer service and consumer protection performance]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, York Water Company base rate increase, Docket Nos. R-2022-3031340, R-2022-3032806 (August and September 2022) [Base rate case: analysis of customer service and consumer protection performance]

Direct, Rebuttal and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Columbia Gas of Pennsylvania Proposal for Green Path Tariff, Docket Nos. R-2022-3032167 and C-2022-3032404 (December 2022 and January and February 2023) [Proposal to offer an optional "green" product to residential customers with Renewable Natural Gas and Carbon Offsets]

Direct, Rebuttal, and Surrebuttal Testimony on behalf of AARP Maine before the Maine Public Utilities Commission, Central Maine Power Company Request for Distribution Rate Increase and Rate Design Changes, Docket No. 2022-00152 (December 2022, March and April 2023) [Rate impacts; multi-year rate plan; rate design]

Direct and Surrebuttal Testimony on behalf of AARP Maine before the Maine Public Utilities Commission, Versant Power Request for Approval of Rate Change, Docket No. 2022-00255 (January and April 2023) [Rate impacts, AMI costs and benefits]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Application of Manwalamink Water and Sewer and NextEra Water Pennsylvania, Docket Nos. A-2022-3035298, et al. (January and March 2023) [consumer protection; service quality; acquisition of small water and sewer utility]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, National Fuel Gas Distribution Corp. Base Rate Case, Docket No. R-2022-3035730 (January and March 2023) [analysis of consumer protection and service quality performance in base rate case]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Philadelphia Gas Works Base Rate Case, Docket No. R-2023-3037933 (May and July 2023) [analysis of consumer protection and service quality performance in base rate case]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, FirstEnergy Pennsylvania Electric Distribution Companies Application for Merger, Docket No. A-2023-3038771 et.al (June and August 2023) [analysis of implication of proposed merger for customer service performance and low income programs]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pittsburgh Water and Sewer Authority Base Rate Case, Docket No. R-2023-3039920, et al., (August and September 2023) [customer service performance; compliance with statutory and regulatory rules; multi-year rate plan conditions]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Application of Pennsylvania-American Water Co. to Acquire Wastewater Assets of Borough of Brentwood, Docket No. A-2021-3024058 (October and November 2023) [analysis of public benefits of acquisition]

Direct, Supplemental Direct, and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Pennsylvania American Water Co., Docket Nos. R-2023-3043189 and R-2023-3043190 (February and March 2024) [customer service performance, compliance with statutory and regulatory rules; billing for non-basic services; tariffs]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Peoples Natural Gas Company LLC, Docket No. R-2023-3044549 (March and May 2024) [customer service performance, compliance with statutory and regulatory rules; billing for non-basic services; tariffs]

Direct, Rebuttal, and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Petition of PECO Energy for Default Service Program for June 1, 2025 through May 31, 2029, Docket No. P-2024-3046008 (April and May 2024) [Retail Market Enhancement Programs; Standard Offer Program; TOU Rate; Billing Disclosures]

Direct, Rebuttal and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Petition of PPL Electric for Default Service Program for June 1, 2025 through

May 31, 2029, Docket No. P-2024-3047290 (June and July 2024) [Retail Market Enhancement Programs; Standard Offer Program; TOU Rate; Billing Disclosures]

Direct, Rebuttal and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Petition of Duquesne Light Co. for Default Service Program for June 1, 2025 through May 31, 2029, Docket No. P-2024-3048592 (July and August 2024) [Retail Market Enhancement Programs; Standard Offer Program; TOU Rate; Billing Disclosures]

Direct, Rebuttal and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. FirstEnergy Pennsylvania, Docket No. R-2024-3047068 (June, July, and August 2024) [customer service performance, compliance with statutory and regulatory rules; billing for non-basic services; tariffs; EV rate pilots; management performance; payment processing fees; root cause analysis]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Aqua Pennsylvania, Docket Nos. R-2024-3047822 (Water) and R-2024-3047824 (Wastewater) (August and September 2024) [customer service performance, compliance with statutory and regulatory rules; payment processing fees; tariffs; management performance; root cause analysis]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission, Pennsylvania PUC v. UGI Utilities, Inc.—Gas Division, Docket No. 2024-R-3052716 (April-May 2025) [customer service performance, compliance with statutory and regulatory rules, management performance, root cause analysis, billing for supplier charges]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Philadelphia Gas Works, Docket No. 2025-R-3053112 (May-July 2025) [customer service performance, compliance with statutory and regulatory rules, management performance, root cause analysis, billing for supplier charges]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2025-3053499 (June-July 2025) [customer service performance, compliance with statutory and regulatory rules, management performance, root cause analysis, billing for supplier charges]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. The York Water Co., Docket Nos. R-2025-3053442, et al. (August-October 2025) [customer service performance, compliance with statutory and regulatory rules, management performance, root cause analysis, low income programs and policies]

Direct and Surrebuttal Testimony on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, Pennsylvania PUC v. Pittsburgh Water and Sewer Authority, Docket Nos. R-2023-3039920, et al. (September-October 2025) [customer service performance, compliance with statutory and regulatory rules, management performance, root cause analysis; payment fees]

Exh. BA-2
UGI Gas Response to OCA-3-1(a) with 2025 average calculations

UGI UTILITIES, INC.
Monthly Call Center Performance
January 2023 - January 2026

Month	Calls Received	Answer by Agent	Calls Answered within 30 sec.	Average Speed of Answer (sec.)	Busy Out
January-2023	173,559	94,873	69.9%	403.51	0
February-2023	155,274	83,208	71.3%	403.66	0
March-2023	188,924	99,627	72.3%	462.66	0
April-2023	153,810	84,425	80.5%	308.00	0
May-2023	142,299	80,013	88.5%	97.65	0
June-2023	134,991	76,528	89.2%	74.57	0
July-2023	127,819	72,364	91.2%	60.36	0
August-2023	137,437	79,907	91.0%	36.64	0
September-2023	145,108	81,886	84.3%	120.56	0
October-2023	169,187	97,764	79.7%	176.13	0
November-2023	168,210	94,316	80.5%	230.52	0
December-2023	110,803	57,718	90.5%	16.19	0
January-2024	127,328	69,106	90.5%	51.36	0
February-2024	120,373	63,319	87.0%	113.99	0
March-2024	117,684	60,153	89.9%	67.83	0
April-2024	131,855	69,075	81.4%	182.72	0
May-2024	119,326	64,040	88.3%	62.79	0
June-2024	114,049	57,385	87.7%	84.95	0
July-2024	125,305	64,175	85.4%	85.58	0
August-2024	114,682	63,429	84.9%	70.03	0
September-2024	116,563	62,735	79.1%	161.73	0
October-2024	140,102	76,045	77.4%	221.03	0
November-2024	114,954	59,287	82.7%	132.55	0
December-2024	108,736	54,180	91.2%	91.14	0
January-2025	125,343	63,321	90.7%	50.89	0
February-2025	126,497	61,037	82.9%	205.17	0
March-2025	132,686	64,109	87.9%	108.44	0
April-2025	123,959	61,050	84.8%	166.10	0
May-2025	121,248	59,862	85.6%	119.14	0
June-2025	109,785	58,087	88.2%	60.62	0
July-2025	116,951	62,746	90.5%	46.15	0
August-2025	119,995	64,746	87.2%	71.76	0
September-2025	119,178	65,521	88.3%	66.53	0
October-2025	146,017	78,587	76.9%	226.29	0
November-2025	113,791	58,338	79.7%	183.20	0
December-2025	114,758	58,574	90.7%	78.95	0

January-2026	121,912	62,568	90.2%	50.72	0
2025 Average			86.1%		

ıt OCA-3-1(a)
o

Abandoned %
9.46%
9.51%
11.95%
8.28%
3.77%
3.13%
2.76%
3.41%
7.01%
10.76%
12.71%
2.84%
2.44%
3.82%
3.04%
7.38%
2.88%
3.31%
3.45%
3.35%
6.72%
7.79%
4.55%
4.00%
2.13%
6.14%
4.35%
4.73%
3.95%
2.93%
3.27%
3.92%
4.23%
9.57%
7.51%
4.18%

3.22%

4.7%

UGI UTILITIES, INC.
Annual Call Center Performance
Calendar Years 2023, 2024, 2025 and 2026

Calendar Year	Calls Received	Answer by Agent	Calls Answered within 30 sec.	Average Speed of Answer (sec.)	Busy Out	Abandoned %
2023	1,807,421	1,002,629	82.4%	199.20	0	7.13%
2024	1,450,957	762,929	85.5%	110.48	0	4.39%
2025	1,470,208	755,978	86.1%	115.27	0	4.70%
2026*	121,912	62,568	90.2%	50.72	0	3.20%

*Through January 2026

Exh. BA-3
UGI's proposed field operations training materials
(CONFIDENTIAL)

Exh. BA-4
UGI Gas Response to OCA-6-12

OCA-6-12

Request:

Refer to Joint Petition for Approval of Settlement of All Issues in UGI's most recent general rate increase request at Docket Nos. R-2024-3052716, Paragraph 86.

a. Please provide UGI Gas's documented and formalized processes using root cause analyses or apparent cause evaluations.

b. Has UGI Gas conducted an RCA or ACE using this documented and formalized process, yet?

Response:

The Company is currently working to document and implement a formalized process using Root Cause Analyses ("RCA") or Apparent Cause Evaluations ("ACE"), as circumstances warrant. The progress toward this objective is described below.

The Company has aggregated and manually analyzed historical records to identify how to categorize and code formal and informal complaint records. This consistent coding will enable the company to identify and track trends and potential areas needed for investigation. Development of system enhancements to capture this data is in progress. In the near term, the Company continues to code complaints manually and has developed a dashboard to monitor complaints and compare year-over-year and formalized the process to review this data with all internal stakeholders each month.

Additionally, the Company is in the process of standardizing internal documentation of identified justified complaints to ensure all critical details are readily available, should an RCA or ACE be required.

The Company has also standardized the process to communicate and track employee errors found through justified complaints to better identify potential gaps in training and coaching.

As a result of these efforts, the Company has identified some scenarios that warrant further analysis and is now positioned to begin formalizing the RCA and ACE process.

In alignment with settlement requirement paragraph 86, "UGI Gas will provide a report to CAUSE-PA, CEO, I&E, the OCA, and the OSBA annually, describing its progress and

OCA-6-12 (Continued)

the results of its review and implementation of the RCA and/or ACE process, with the first report being provided on or before October 1, 2026, until a final Commission order is entered in UGI Gas's next base rate proceeding." The Company is on track to provide a report to CAUSE-PA, CEO, I&E, OCA and OSBA, the results of its review and implementation of the RCA and/or ACE process, on or before October 1, 2026.

Prepared by or under the supervision of: Daniel V. Adamo

Exh. BA-5
UGI Gas Response to OCA-3-10.2

<NAME 1>
<NAME 2>
<MAILING ADDRESS 1>
<MAILING ADDRESS 2>
<MAILING ADDRESS 3>

<DATE>

Account: <ACCOUNT NUMBER>
<SERVICE ADDRESS 1>
<SERVICE ADDRESS 2>

Hello,
This letter is to confirm that you spoke with a representative of UGI Utilities and agreed to the Payment Arrangement terms shown below. By accepting this arrangement, you accepted the charges that are included.

Date of Arrangement:	<DATE ARRANGEMENT MADE>
Total Arrangement:	$<INSTALLMENT PLAN TOTAL>
Installment Term:	<MONTHLY TERM> months
Installment Amount:	$<MONTHLY INSTALLMENT AMOUNT>
Estimated Due Date:	**<DUE DATE OF NEXT PAYMENT>**

Starting with your next bill, you will be responsible for the Installment Amount plus your full current monthly charges.

If you do not pay the amount agreed upon by the due date and your service is disconnected due to non-payment, your Payment Arrangement will be canceled and you may be required to pay the full overdue amount to reconnect.

If you have any questions, please contact UGI at 800-276-2722, Monday through Friday from 8:00 a.m. and 5:00 p.m.

Thank you,
UGI Utilities

Exh. BA-6
UGI Gas Response to OCA-3-8

OCA-3-8

Request:

Provide a copy of a Rate RT residential bill in use by the Company for Pennsylvania customers. Please redact all customer identifying information.

Response:

Please see Attachment OCA-3-8.

Prepared by or under the supervision of: Daniel V. Adamo

UGI UTILITIES - GAS DIVISION
SAMPLE RATE RT BILL
FEBRUARY 2026

Energy to do more®

Billing Summary for Service to:

[redacted]

Rate Classification (RT):
Residential Heating-CC

Billing Period:
01/09/2026 to 02/05/2026 (28 days)
Actual Read

Questions?
Call (800) 276-2722 or write to UGI at
PO Box 13009
Reading, PA 19612-3009
*Your current UGI charges include State taxes totaling about $0.52.

Past Bill Information

The balance on your last bill was	$61.96
Thank you for your payment of	-62.00
Amount due as of 02/10/2026	-0.04

Account Number
[redacted]

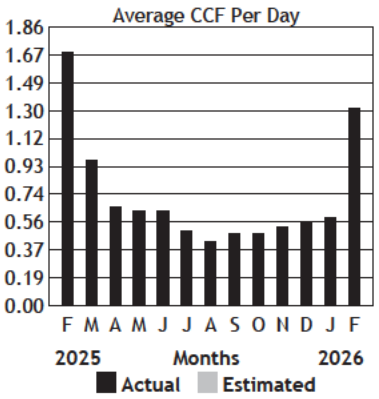
Current Bill Information

Customer Charge	16.25
Supplier Commodity (37 CCF at $1.57020)	58.10
Distribution Charges (37 CCF at $0.71622)	26.50
Weather Normalization Adjustment	-1.90
Natural Gas System Improvement Charge	0.13
Current Charges	99.08

Utility charges owed this bill **$99.04**

Current Bill Information - [redacted] natural gas costs are shown in the supplier charges above.

Total Amount Due By 03/03/2026 ..... **$99.04**



Average	Last Year	This Year
CCF/Day	1.69	1.32
Daily Temperature	27°F	25°F

Meter Information - Next Read Date March 10, 2026

Meter Number	Previous Reading	Present Reading	CCF Used
[redacted]	6758	6795	37

Shopping Information Box

- UGI Natural Gas Price to Compare is $0.69874/CCF.
- When shopping for natural gas with a Natural Gas Supplier, please provide the following data below. If you are already shopping, know your contract expiration date.

Account Number: [redacted] Rate Schedule: RT_H

Supplier Information
[redacted]

- Commodity prices and charges are set by the natural gas supplier you have chosen. The Public Utility Commission regulates distribution prices and services.

If you pay at a payment agent please take your entire bill. Make check payable to UGI.
Keep this part for your records. Important information is on the back of this bill.

Energy to do more®

UGI Utilities, Inc.
PO Box 15503
Wilmington, DE 19850-5503

Account Number
[redacted]

Please pay by the due date to avoid the late charge. Please return this portion with your payment.

[redacted]

Due Date
March 03, 2026

Amount Due
$99.04

With Late Charge
$100.52

[redacted]

UGI Invoice Number: [redacted]

GENERAL INFORMATION

Bill Questions?

If you have a question about the bill, please call UGI before the bill's due date. UGI's phone number, your due date and billing rate can be found on the front of the bill. A detailed rate schedule can be requested. You may also contact UGI at our web site, www.ugi.com

Hearing or speech impaired customers. TDD only, call 1-800-654-5988. To discuss an overdue account, call 1-800-276-2722, weekdays 8AM to 5PM.

Bill Payments

Paying your bill by mail is convenient. Simply use the envelope provided with your bill. You may also pay at one of your payment centers. A list of the payment centers is available upon request. UGI offers a plan where your bank deducts your payment automatically from your checking or savings account. Please call us if you are interested in this service. To pay by phone, please call 800-276-2722.

Need Your Natural Gas Service Turned Off?

To ensure that your Natural Gas service is turned off on the day that you want, please contact UGI seven days in advance.

Third Party Notification - Budget Billing Plan — Operation Share — Customer Assistance Program (CAP) Call us to discuss these UGI Programs.

EXPLANATION OF TERMS

Bill Proration — If there are rate changes during a billing cycle, the customer's bill will include prorated charges based on the timing of the rate changes within the billing period.

CCF — 100 cubic feet of gas. **MCF** — 1,000 cubic feet of gas. This is a measure of gas usage.

Commodity Charges or Purchased Gas Adjustment — The amount billed each month for gas supply service sold by volume (CCF or MCF).

Customer Charge — A monthly charge to cover natural gas distribution company (NGDC) costs such as maintaining the gas lines, meter reading and billing.

Distribution Charges — The charges for delivery of natural gas from the point of receipt into the NGDC's system.

Estimated Bill — A bill based on your previous use and weather conditions. UGI may need to estimate your bill due to extreme weather conditions, emergencies, or any other circumstances that prevent UGI from taking a meter reading.

Heat Value Correction — A correction factor applied to metered usage to adjust for gas heating values that locally differ from system average heating values. Not applicable to Maryland customers.

Late Payment Charge — Fee that UGI charges if you do not pay your bill on time. It is a fixed monthly percentage of the amount owed.

Maryland Franchise Tax — A tax surcharge for the recovery of the Maryland Franchise Tax. Not applicable to Pennsylvania customers.

Price to Compare — The dollar amount charges by the NGDC, used by consumers to compare prices and potential savings with other natural gas suppliers. Not applicable to Maryland customers.

State Tax Surcharge — A charge approved by the Pennsylvania Public Utility Commission. It is a special charge to recover state taxes UGI pays. Not applicable to Maryland customers.

System Improvement Charge — A charge used to recover costs for repairing, improving or replacing distribution facilities in order to provide safe, reliable and efficient service. Not applicable to Maryland customers.

Weather Normalization Adjustment (WNA) — Is a method of billing distribution charges based on "normal" weather approved by the Pennsylvania Public Utility Commission. Not applicable to Maryland customers.

EMERGENCIES: to report a **Gas Leak,** call **1-800-276-2722, 24 hours a day**

Energy to do more®

Account Number

[redacted]

Important message(s) from UGI

- Your distribution charges have been adjusted to reduce the impact of colder than normal weather.
- Your natural gas total annual usage is 235 CCF. Your natural gas average monthly usage is 20 CCF.

Exh. BA-7
UGI Gas Response to CAUSE PA 5-10

CAUSE-PA-5-10

Request:

Please provide a copy of all reports, analyses, and/ or studies conducted by UGI or a UGI consultant or contractor that examine the trends, patterns, and/ or disparities between the prices paid by default service customers and shopping customers, including but not limited to, any general reports, analyses, or studies related to trends, patterns, and/ or disparities between default service customers and shopping customers, and any reports, analyses, or studies focused on specific retail market programs or policies.

Response:

Please see Attachment CAUSE-PA-5-10 provided in Excel and PDF.

Prepared by or under the supervision of: Jessica R. Rogers

UGI Utilities, Inc. - Gas Division
Rate RT - Residential Transportation Statistics

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	In Summary
Average Customer Usage/Mcf	16.0	16.5	12.1	6.8	3.3	2.2	1.5	1.3	1.5	2.0	5.4	12.2	6.7
Average Cost of Natural Gas Supply Service on Choice $/Mcf	$ 8.7251	$ 8.6501	$ 8.5983	$ 8.6653	$ 8.7133	$ 8.7908	$ 8.9519	$ 9.2019	$ 14.1571	$ 11.6873	$ 11.6076	$ 11.1495	$ 9.9082
Percentage of Average Supplier Rate Above Price to Compare	49.9%	48.6%	26.0%	29.3%	27.7%	28.9%	31.2%	34.9%	107.5%	71.3%	69.7%	59.6%	48.7%
Total Number of Customers Shopping	82,802	73,509	80,797	81,591	79,727	77,278	75,935	72,066	73,240	84,809	73,288	85,732	78,398
Number of Customers Paying More than the Price to Compare	68,996	60,021	57,781	59,912	58,454	56,974	56,149	54,034	57,290	66,852	57,955	67,467	60,157
Percentage of Customers Paying More than the Price to Compare	83.3%	81.7%	71.5%	73.4%	73.3%	73.7%	73.9%	75.0%	78.2%	78.8%	79.1%	78.7%	76.7%
Total Dollars Charged in Excess of Price to Compare	$ 3,914,195.23	$ 3,540,320.32	$ 2,036,960.38	$ 1,225,537.84	$ 574,207.16	$ 382,728.16	$ 266,409.69	$ 248,710.19	$ 422,434.18	$ 561,592.10	$ 1,103,556.15	$ 2,767,727.25	$ 17,044,378.67

UGI Utilities, Inc. - Gas Division
Rate NT - Non-Residential Transportation Statistics

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	In Summary
Average Customer Usage/Mcf	94.5	95.1	70.7	42.8	27.1	22.3	20.8	20.3	21.6	22.9	35.7	62.2	44.7
Average Cost of Natural Gas Supply Service on Choice $/Mcf	$ 8.3513	$ 8.0790	$ 7.9260	$ 7.9367	$ 7.8997	$ 7.8502	$ 7.8921	$ 7.7228	$ 7.8418	$ 8.0156	$ 8.3139	$ 8.9516	$ 8.0651
Percentage of Average Supplier Rate Above Price to Compare	46.0%	41.3%	18.3%	18.4%	17.9%	17.1%	17.8%	15.2%	17.0%	19.6%	23.9%	30.6%	23.6%
Total Number of Customers Shopping	15,370	13,299	14,676	14,448	13,668	12,620	10,851	9,866	10,190	13,059	12,336	12,553	12,745
Number of Customers Paying More than the Price to Compare	12,632	10,822	8,932	8,860	8,275	7,435	6,703	5,939	5,885	7,823	7,835	8,766	8,326
Percentage of Customers Paying More than the Price to Compare	82.2%	81.4%	60.9%	61.3%	60.5%	58.9%	61.8%	60.2%	57.8%	59.9%	63.5%	69.8%	64.8%
Total Dollars Charged in Excess of Price to Compare	$ 2,616,989.07	$ 2,159,578.88	$ 1,032,593.78	$ 564,127.37	$ 284,839.01	$ 186,517.34	$ 152,119.54	$ 129,508.98	$ 148,110.43	$ 228,296.46	$ 482,881.53	$ 1,079,797.39	$ 9,065,359.76

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Barbara R. Alexander, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 5, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: */s/ Barbara R. Alexander*
Barbara R. Alexander

Address: Barbara Alexander Consulting LLC
44 Beech Street
Hallowell, ME 04347

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	DOCKET NO. R-2025-3059523
v.	:	
UGI UTILITIES, INC.-GAS DIVISION	:	

SURREBUTTAL TESTIMONY

BARBARA R. ALEXANDER
BARBARA ALEXANDER CONSULTING LLC

ON BEHALF OF

OFFICE OF CONSUMER ADVOCATE

OCA Statement 5-SR

Date Served: May 27,2026

Q. **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION**.

A. My name is Barbara R. Alexander. I am the sole member manager of Barbara Alexander Consulting LLC. My address is 44 Beech St., Hallowell, ME 04347. I appear in this case as a witness on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. **HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?**

A. Yes. I submitted direct testimony on behalf of the OCA on April 13, 2026.

Q. **WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

A. I will respond to the Rebuttal Testimony of UGI-Gas Witnesses Daniel Adamo (Statement No. 13-R), Jill Walter (Statement No. 3-R), John Taylor (Statement No. 11-R), and Jessica Rogers (Statement No. 15-R). I will organize my response based on each of my recommendations.

Q. **DO YOU HAVE EXHIBITS ATTACHED TO YOUR TESTIMONY?**

A. Yes. I attach the following Exhibits:

- Exhibit BA-8: Workpaper, UGI Gas Witness Adamo, Table 1.
- Exhibit BA-9: Supplemental Response to OCA-3-1(a) and accompanying spreadsheet attachment.

Q. **DID UGI WITNESSES ADAMO AND WALTER PROVIDE UPDATED INFORMATION ON COMPLIANCE WITH THE PRIOR RATE CASE SETTLEMENT REQUIREMENTS THAT YOU DISCUSSED IN DETAIL IN YOUR DIRECT TESTIMONY?**

A. Yes. It is important to point out that Mr. Adamo did not submit testimony in UGI-Gas' filing for this base rate case and no UGI witness discussed all the customer service settlement conditions in the initial filing. My overarching concern about the lack of any

comprehensive presentation of those conditions and the status of compliance with those customers was correct. Furthermore, while Mr. Adamo and Ms. Walter did update more current developments in their Rebuttal, in most cases my description of the status of those requirements was correct at the time of my testimony. Finally, it is a fact that UGI Gas filed its current base rate case prior to many of the deadlines set forth in the 2025 rate case settlement, thus preventing a comprehensive analysis of compliance with those commitments.

Q. **DO YOU HAVE ANY CHANGES TO YOUR CONCLUSIONS AND RECOMMENDATIONS?**

A. No. My recommendations support the overall recommendations of other OCA witnesses to either reject the Company's rate increase, or substantially lower any rate increase in this proceeding. The following summarize my recommendations that were documented and presented in more detail throughout my testimony:

- UGI Gas has not completed many of the agreed upon service quality and customer service conditions ordered in the last rate case and, at a minimum, the Commission should monitor and ensure compliance with those conditions prior to considering any further rate increases.
- UGI has adopted internal performance and compliance related performance indicators for its third party call contractors that I support. The Commission should require UGI to implement and report on these performance indicators to avoid any deterioration of service and to properly monitor third party call centers.
- UGI should adopt additional and more targeted customer communications to assist customers in ensuring affordability for basic natural gas service due to high NGS charges

that appear on the customer bill that UGI collects under threat of termination of service. In addition, UGI's bill should be reformed to more directly link the presentation of NGS charges with the PTC.

Q. **IS YOUR PROPOSAL THAT UGI GAS MEET ITS OWN INTERNAL CALL CENTER PERFORMANCE STANDARDS AS A CONDITION OF ANY RATE INCREASE INTENDED TO BE A PERFORMANCE BASED RATE?**

A. Absolutely not. My proposal relates directly to the Company's proposal to raise rates and is intended to ensure that any rate increase does not result in any deterioration of customer service during the rate effective year. The internal management call center performance standards are directly related to the expenses and rates proposed in this proceeding. It is entirely proper and reasonable to consider the link between management's own internal objectives to operate its call center at a high level and the rate increase sought in this proceeding.

Q. **PLEASE SUMMARIZE MR. ADAMO'S REBUTTAL TESTIMONY ON THE UGI CALL CENTER PERFORMANCE.**

A. Mr. Adamo states, "…there is no question that the Company met its call center metrics when comparing 2024 to 2025."[1] His Exhibit DVA-3R presents the UGI Gas 2024 performance and 2025 performance and then compares those results with 2024 results for Columbia, National Fuel, Peoples, and PGW. He asserts that UGI Gas results should properly be compared to Peoples due to the size of customer base. With regard to the UGI Abandonment Rate, he states that the Company responds to high call months with staffing

[1] St. No. 13-R, page 4, lines 5-6.

changes.[2] He states that I identified an "alleged variability in call abandonment rates." He then provides a Table 1 that compares the Abandonment Rate Selected Months for 2024-2026 with Fiscal Year data. His Table provides the Abandonment Rate for "Fiscal Year" 2024, 2025, and 2026 for October, November, February and "Full Calendar Year" Rate for 2024 and 2025. Based on this data, he states that the actual results showing any increase in the Abandonment Rate are not statistically meaningful and the Abandonment Rate has not "meaningfully changed."

Q. **PLEASE RESPOND TO MR ADAMO'S PRESENTATION OF THE UGI GAS CALL CENTER PERFORMANCE RESULTS.**

A. Mr. Adamo's presentation suffers from several defects. First, he compares "fiscal year" with "calendar year" information. The correct comparison is between the calendar year 2024 performance with the calendar year 2025 performance as required by the 2025 base rate case settlement. Second, he provided information in Table 1 that was not provided in discovery. Mr. Adamo's Rebuttal was filed on May 13. UGI did not provide any workpapers associated with his testimony until May 18 after a request by OCA for the workpapers associated with his Table 1. I attach the workpaper UGI provided on May 18 as Exhibit BA-8. As stated in this document:

> Note: The Abandonment Rate data provided for the months of October, November, and December 2023 do not match response to OCA-3-1(a). The data shown for those three months have been revised to align with more accurate telephony reporting available data and presented in Table 1 of Statement No. 13-R, Rebuttal Testimony of Daniel V. Adamo.

As a result, Mr. Adamo has submitted information that differs from that provided

[2] Ibid., page 4, line 12 through page 5, line 12.

in discovery in response to OCA-3-1(a) without any disclosure of that change in his rebuttal testimony. In response to discovery issued on the OCA on May 19, UGI filed an updated response to OCA-3-1(a) on May 20. I attach that supplemental data response as Exhibit BA-9. Additional discovery is now pending to explore the underlying basis for this change in results. Based on the updated data filed on May 20, UGI has made corrections to the 2023 Abandonment Rate that reflects worse performance than previously reported. There is no change in the data provided for 2024 and 2025 that I relied upon in my direct testimony when discussing the implementation of the 2025 base rate case settlement. The impact of the 2023 data is only relevant when included in Mr. Adamo's presentation of the "fiscal year" data in his Rebuttal and is not relevant to the 2025 rate case settlement at issue.

Q. **PLEASE SUMMARIZE YOUR RESPONSE TO MR. ADAMO'S ATTEMPT TO EXCUSE THE DETERIORATION IN THE 2025 ABANDONMENT RATE RESULT.**

A. My testimony is correct. The 2025 calendar year result reflects a higher Abandonment Rate result compared to 2024. I recognize that this result is relatively small but does reflect as well the higher Abandonment Rates for months in which the call volume is highest. Mr. Adamo's claim that the Company alters staffing to reflect the months of higher call volumes has not prevented poor customer experience in attempting to reach the Company to handle vital transactions related to disconnection of service in those very months he claims the Company has taken steps to improve call performance.

Q. **BASED ON THE INFORMATION YOU HAVE AVAILABLE TO DATE, HAS UGI GAS MET OR IMPROVED ITS 2025 CALL CENTER PERFORMANCE METRICS COMPARED TO 2024?**

A. No. The annual average Abandonment Rate increased from 4% in 2024 to 4.7% in 2025. This data confirms that customers experienced poor service in several months, a pattern that was also reflected in the 2024 data. Finally, while not required by the prior settlement, UGI Gas' performance is below that of other Pennsylvania natural gas utilities, a performance that should be taken into account in this base rate case results and supports my recommendation for the call center performance results that should be required in this base rate case. Mr. Adamo's attempt to present data to show a different result or excuse their actual results should be rejected.

Q. **HAS UGI GAS COMPLIED WITH THE REQUIREMENT TO PROVIDE CUSTOMER SERVICE RESULTS TO THE UNIVERSAL SERVICE ADVISORY COMMITTEE?**

A. Mr. Adamo correctly states that the required data has been provided as of the end of April 2026.[3] This occurred after the submittal of my direct testimony. He states that the Committee is scheduled to review this data in its June 2026 meeting. I acknowledge that this data submittal requirement has now been complied with.

[3] Ibid., page 6, lines 1-12

Q. **HAS UGI GAS COMPLIED WITH THE REQUIREMENT TO CONDUCT A ROOT CAUSE ANALYSIS FOR CERTAIN COMPLAINTS?**

A. No. UGI Gas is in the process of conducting such an analysis as I stated in my direct testimony. As a result, it is not possible to determine if UGI Gas has complied with this 2025 base rate case order and settlement.

Q. **HAS UGI GAS COMPLIED WITH THE REQUIREMENT TO REVISE ITS COMMUNICATIONS AND TRAINING RELATED TO ITS WEATHER NORMALIZATION ADJUSTMENT (WNA)?**

A. Yes, in part. Several communication and training related commitments are not yet implemented. However, as I stated in my direct testimony, the resulting customer communications continue to struggle to provide useful information on a very complicated formula and program details. A discussion with stakeholders and solicitation of input that may or may not be accepted by the utility is not dispositive of any review of the final results in this request for higher rates and continuation of the WNA. Most importantly, I find that these communications fail to properly inform customers about the historical result of this billing adjustment which has consistently resulted in higher charges compared to charges that provide a credit due to the WNA formula. The actual implementation of the changes that the Company intends to implement is in the process of being implemented but was not yet completed at the time of my direct testimony. In the context of this base rate case, I made recommendations to further improve the content of these customer communications.

Q. **PLEASE RESPOND TO UGI WITNESS TAYLOR'S STATEMENT THAT THE COMMISSION SHOULD CONSIDER THE LACK OF CUSTOMER COMPLAINTS AS A SIGNAL OF CUSTOMER ACCEPTANCE OF THE WNA.**

A. Mr. Taylor's assertion that the lower number of customer complaints can be interpreted as either customer understanding of the WNA or acceptance of its impact on their bills[4] is not reasonable. He provides no evidence to support this interpretation to explain a lower number of customer complaints about the WNA. Rather, it may well be that customers have "given up" in complaining about a charge on their customer bill because of the repeated Commission approval of the mechanism and frustration with lack of response to their concerns. It is not appropriate to make a conclusion about this complaint trend without further analysis which Mr. Taylor has not done.

Q. **HAS UGI GAS MOVED THE PRESENTATION OF THE PRICE TO COMPARE TO THE FRONT PAGE OF ITS BILL?**

A. Yes. I acknowledged that change as required by the 2025 settlement in my direct testimony. I then made further recommendations due to the now obvious difference in the nomenclature that appear on the customer bill to refer to the Natural Gas Supplier's (NGS) "commodity charge" with the "price to compare" (PTC), suggesting that these different terms may confuse customers who need to compare the NGs charges to the PTC as promoted by the Commission's and the UGI customer shopping educational materials. I continue to recommend that UGI's bill should explicitly inform the customer of this

[4] UGI St. No. 11-R, at 41.

linkage. I agree that the term PTC should not change,[5] but my recommendation should be interpreted to require that the PTC presentation should tell the customer to compare this rate to the NGS "commodity charge."

Q. **HAS UGI GAS NOW DISCLOSED THAT THE CUSTOMER CAN USE PAYMENT METHODS VENMO AND APPLE PAY ON ITS PUBLIC FACING WEBSITE?**

A. Yes. The current version of its public facing website now includes a reference to the use of Venmo and Apple Pay methods.[6] However, when I reviewed the website at the time of preparing my direct testimony, the information about the use of Venmo and Apple Pay was not included on this website. I acknowledge this disclosure is now available and agree that this provision of the 2025 rate case settlement has been complied with. I support the Company's expansion of widely used customer payment methods for UGI bills.

Q. **MR. ADAMO REJECTS YOUR RECOMMENDATION THAT ITS NEWLY DEVELOPED PAYMENT ARRANGEMENT CONFIRMATION LETTER SHOULD INCLUDE A NOTICE OF CUSTOMER RIGHTS. DO YOU AGREE?**

A. No. Mr. Adamo correctly states that UGI has developed (and I acknowledged) a written communication to the customer upon entering into a payment arrangement as per the 2025 rate case settlement. Having now reviewed that letter, I pointed out a serious omission, that is, no information on the customer's rights to dispute the terms or contact the Commission to initiate an informal complaint. Mr. Adamo testifies that unless the prior

[5] UGI St. No. 13-R, page 7, line 18 to page 8, line 2.
[6] Ibid., page 9, lines 8-17.

settlement required that this communication include a notice of customer rights, no such requirement should be implemented.[7] Mr. Adamo's refusal to include the required customer rights in this communication should be rejected for the reasons set forth in my Direct Testimony. As a condition of any rate increase in this proceeding, UGI Gas should be required to promptly add the standard disclosures about customer rights to this communication.

Q. **MR. ADAMO COMPLAINS THAT IN SOME CASES I HAVE INCLUDED NEW RECOMMENDATIONS IN RESPONSE TO UGI'S COMPLIANCE ACTIVITIES FOR THE 2025 BASE RATE CASE ORDER AND SETTLEMENT. DO YOU AGREE?**

A. I understand that the compliance with the prior settlement is separate from any recommendations I make in this proceeding based on my evaluation of the results of the prior settlement as well as my review of UGI's more recent customer service performance. It is reasonable to not only review the prior settlement but to review and evaluate the actual customer service performance results in this base rate case proceeding. The Company has made this dual charge difficult by filing a new base rate case prior to the completion of the settlement conditions in the 2025 order and settlement.

Q. **SHOULD THE COMMISSION ADOPT ADDITIONAL CALL CENTER PERFORMANCE REQUIREMENTS IN THIS BASE RATE CASE?**

A. Yes. Whether or not UGI has complied with the prior settlement commitments, this base

[7] Ibid., page 7, lines 14-16.

rate case requires consideration of future performance beyond 2025. Mr. Adamo's reference to "compliance" in recent audits[8] is not dispositive of the obligation to consider customer service performance in the context of a proposal to raise rates in a base rate case. My recommendation is that any rate increase ordered in this proceeding be accompanied by a requirement that the Company's own internal call center performance standards be met in the rate effective year. This recommendation is directly linked to the request for higher rates to ensure that there is no deterioration in performance in the future.

Q. **TURNING TO YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE IMPACT OF NGS CHARGES THAT ARE COLLECTED BY UGI GAS, PLEASE SUMMARIZE MR. ADAMO'S REJECTION OF YOUR RECOMMENDATIONS.**

A. Mr. Adamo rejects my proposal to adopt additional and more targeted customer communications in light of my evidence that UGI Gas residential customers regularly pay more to retain essential natural gas service compared to the applicable PTC. His Rebuttal relies on his statements that the Company complies with current billing and customer communication "regulations."[9] He then identifies costs that would be required to implement the more targeted communications.

[8] Ibid., at 11-12.
[9] Statement No. 13-R, at 13, line 5.

Q. **HOW DO YOU RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY THAT REFUSES ANY NEW INITIATIVES TO CONFRONT THE EVIDENCE OF HIGHER NGS CHARGES?**

A. Mr. Adamo does not rebut the evidence that I included in my testimony that documents the higher prices charged by NGSs to UGI's residential customers. Those higher prices are collected by UGI with collection actions adverse to the customer, including payment arrangements and threats of and actual disconnection of service. Whether or not the Commission has authorized retail shopping or the Purchase of Receivables agreement between UGI and NGSs that allows UGI to bill and collect NGS charges, I recommend that UGI Gas confront the adverse impact on its residential customers of higher charges for the same commodity that UGI provides via its default service obligation and take steps to communicate more targeted educational messages. My recommendations also directly impact the costs of collecting high NGS charges that flow through base rates. My primary recommendation is to eliminate the notion of "saving" as a primary motivation to shop since that is factually incorrect in terms of what UGI knows is the actual result. With regard to additional communications I recommend, UGI Gas has the discretion to develop those messages in addition to any required messaging pursuant to Commission guidance. I recommend that UGI Gas agree to develop more targeted messages to customers whose NGS charges are in excess of the PTC either on the bill or via email to affected customers. Such messaging should identify the dollar amount of difference being paid by the customer and identify options that the customer may want to consider such as choosing a different supplier, returning to default service, and referring the customer to offers presented on the

Commission's PaPowerSwitch web portal. Such messaging should be the subject to stakeholder review and input and finalized within six months after a final order in this proceeding. With respect to costs that may be incurred, those costs should be compared to the additional costs incurred by UGI Gas to collect charges higher than the PTC from its customers and only incurred if the additional messaging costs are in excess of those currently incurred collection costs.

Q. **DO YOU AGREE WITH THE RECOMMENDATION OF CAUSE-PA WITNESS PATRICK CICERO THAT UGI WITNESS ROGERS REJECTS AS TO MODIFYING THE PURCHASE OF RECEIVABLES (POR) PROGRAM?**

A. I support Mr. Cicero's recommendation to modify the POR program that is the vehicle for allowing NGSs to charge higher prices than the default service supply of commodity natural gas. Ms. Rogers herself has opened the door to consideration of such a proposal: "The Commission can and should evaluate whether UGI Gas's policies and practices adequately meet the needs of customers across income and operational demographics, and whether more can be done to support customer affordability through modifications to programs or policies."[10] The modification of this policy would directly improve the affordability of UGI's bills and impact its collection costs incurred to collect higher NGS charges for the same commodity natural gas that is provided through the default service mechanism.

[10] UGI St. No. 15-R, at 22, lines 3-6.

Q. **HOW DOES UGI WITNESS JILL WALTER RESPOND TO YOUR TESTIMONY ON THE TRAINING MATERIALS FOR UGI FIELD REPRESENTATIVES THAT ADDRESS THE REGULATORY REQUIREMENTS TO ATTEMPT PERSONAL CONTACT IMMEDIATELY PRIOR TO DISCONNECTION OF SERVICE?**

A. UGI Witness Walker's responds to my evaluation of the training materials developed by UGI Gas pursuant to the mandate of the 2025 rate case settlement by stating, "Specifically, it is her belief that these employees should be trained to solicit or inquire about customer rights. Finally, Witness Alexander believes that door knocks should be required during terminations. OCA 13 St. 5, at pp. 14-15."[11] She further states that these employees are not trained in the full range of customer rights and remedies and so, "they are not the appropriate resources to solicit or evaluate this information." [12] She rejects my recommendations to improve and revise the training materials.

Q. **PLEASE RESPOND TO UGI WITNESS WALTER'S BASIS FOR REJECTING YOUR RECOMMENDATIONS TO IMPROVE THE COMPANY'S TRAINING MATERIALS TO EFFECTUATE THE COMMISSION'S REGULATIONS**.

A. First, I remind Ms. Walter about the explicit requirement of the 2025 rate case settlement: "UGI Gas will develop additional training materials for its field representatives by April 1, 2026, including making personal contact with customers prior to termination, and will incorporate these materials into the training of its field representatives."[13] The purpose of

[11] Statement No. 3-R, page 8, lines 11-13.
[12] Ibid., page 8, lines 20-21.
[13] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2024-3052716 (Aug. 8, 2025) Recommended Decision, 127 (summarizing Joint Petition for Settlement ¶ 84) (*R.D. 2025)*.

this obligation is to attempt to make personal contact. Of course, the primary obligation is that the field technician attempts such contact by knocking on the door and be prepared to intelligently engage with the customer or responsible adult about the termination. In my review of compliance with this provision for other Pennsylvania electric, gas, and water utilities I have never encountered any suggestion in opposition to the assumption that this requires at a minimum a knock on the customer's door. Furthermore, the field representative must be prepared to recognize and properly identify and react to the customer rights that have been provided in writing. UGI Gas must train its personnel on the existence of these rights and how to respond if the customer or responsible adult (who may not have received the notice if the customer of record is another adult to whom the mail is directed) raises any objection or concern about the termination of service. If the field agents are not trained on what these rights are and how they must be responded to when encountering the customer or responsible adult, the agents may not properly respond when these rights are invoked or when there is evidence that a conversation about these rights and recognition of these rights should occur. I acknowledge that it may be appropriate for the field representative to engage the UGI customer service office to discuss what the adult has stated and initiate the process of implementation of the customer rights. The purpose of the attempt at contact should require the field technician to at least refer the customer to their rights as stated in the most recent notice and solicit customer statements. If there is visible evidence of criteria that would trigger these rights, such as medical equipment, the field technician should be required to affirmatively inquire as to the existence of a medical emergency. Finally, to suggest that these field representatives do not have to knock on the door and be prepared to intelligently talk about the customer's

rights is contrary to the Commission's regulations and good customer service. I continue to recommend that the training materials developed to date are insufficient and need to be revised as I have set forth in my direct testimony, including the obligation for a written training manual. Based on my review of the training materials provided to date, I conclude that UGI Gas has not made a sufficient effort to comply with the 2025 settlement obligation and should be required as a condition of this rate case to develop the required training materials with the reforms that I have identified and that are consistent with my understanding of prior feedback given by the OCA.

Q. **AS A RESULT OF YOUR REVIEW OF UGI'S COMPLIANCE WITH THE ABOVE LISTED CUSTOMER SERVICE AND CONSUMER PROTECTION SETTLEMENT PROVISIONS IN ITS 2025 BASE RATE CASE, WHAT DO YOU RECOMMEND?**

A. Based on my analysis to date, the Commission should find that the Company has not complied with its intent to meet the 2024 call center performance standards, that the revised training materials for field representatives are defective as I have documented, that the Root Cause Analysis has not been completed, that the confirmation of payment arrangement communication is defective, that the bill presentation of the PTC should be reformed to use the same terms as reflected in the NGS charges, that the WNA communications should be reformed to include an historical presentation of incremental charges and credits, and that the Company is still in the process of implementing its promised alternative bill payment options by the promised deadline. My findings support the position of other OCA witnesses that reject the Company's proposed revenue requirement because it is unreasonable for the Company to ignore these commitments while seeking a significant

new rate increase. If there is any rate increase ordered in this proceeding, I recommend that the Commission require a complete documentation of the prior conditions I have identified in my testimony with my required reforms prior to any implementation of increased rates.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

A. Yes.

Table 1 Data - UGI Utilities
Abandonment Rates

	Month	Aband. %
*	October-2023	**12.0%**
*	November-2023	**14.6%**
*	December-2023	2.9%
	January-2024	2.4%
	February-2024	**3.8%**
	March-2024	3.0%
	April-2024	7.4%
	May-2024	2.9%
	June-2024	3.3%
	July-2024	3.4%
	August-2024	3.4%
	September-2024	6.7%
	October-2024	**7.8%**
	November-2024	**4.6%**
	December-2024	4.0%
	Calendar Year 2024	**4.4%**
	January-2025	2.1%
	February-2025	**6.1%**
	March-2025	4.3%
	April-2025	4.7%
	May-2025	3.9%
	June-2025	2.9%
	July-2025	3.3%
	August-2025	3.9%
	September-2025	4.2%
	October-2025	**9.6%**
	November-2025	**7.5%**
	December-2025	4.2%
	Calendar Year 2025	**4.7%**
	January-2026	3.2%
	February-2026	**4.9%**

* **Note: The Abandonment Rate data provided for the months of October, November, and December 2023 do not match response to OCA-3-1(a). The data shown for those three months have been revised to align with more accurate telephony reporting available data and presented in Table 1 of Statement No. 13-R, Rebuttal Testimony of Daniel V. Adamo**

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to OCA (Supplemental Responses)
Delivered on May 20, 2026

OCA-3-1(a) (Supplemental Response)

Request:

Provide the following monthly and annual average information in an Excel spreadsheet with any formulas intact for the calendar years 2023 through the most recent month for which data is available in 2026:

NOTE: Where available, distinguish customer class for results requested.

a. Call Center Performance: calls received; calls answered by a customer service representative; percentage of calls answered within 30 seconds by a customer service representative; average speed of answer for call answered by a customer service representative, busy out rate; abandonment rate.

Response:

Attachment OCA-3-1(a) was originally compiled using data submitted to the PUC in the annual Customer Service Performance Reports. The Company recently recognized the volume of abandoned calls was found to be inadvertently included twice in the value of Calls Received for Calendar Year 2023 and not adjusted for in the calculation of Abandonment Rate. The Supplemental Attachment OCA-3-1(a) has the revised Calls Received and corrected calculated Abandonment Rate.

Prepared by or under the supervision of: Daniel V. Adamo

UGI UTILITIES, INC.
Monthly Call Center Performance
January 2023 - January 2026

Month	Orig Calls Received	Revised Calls Received	Answer by Agent	Calls within 30 sec.	Calls Answered within 30 sec.	Average Speed of Answer (sec.)	Busy Out	Number of Abandoned Calls	Original Abandoned %	Revised Abandoned %
January-2023	173,559	157,138	94,873	109,842	69.9%	403.51	0	16,421	9.46%	10.45%
February-2023	155,274	140,513	83,208	100,251	71.3%	403.66	0	14,761	9.51%	10.51%
March-2023	188,924	166,356	99,627	120,224	72.3%	462.66	0	22,568	11.95%	13.57%
April-2023	153,810	141,078	84,425	113,625	80.5%	308.00	0	12,732	8.28%	9.02%
May-2023	142,299	136,939	80,013	121,188	88.5%	97.65	0	5,360	3.77%	3.91%
June-2023	134,991	130,770	76,528	116,587	89.2%	74.57	0	4,221	3.13%	3.23%
July-2023	127,819	124,289	72,364	113,320	91.2%	60.36	0	3,530	2.76%	2.84%
August-2023	137,437	132,754	79,907	120,807	91.0%	36.64	0	4,683	3.41%	3.53%
September-2023	145,108	134,931	81,886	113,804	84.3%	120.56	0	10,177	7.01%	7.54%
October-2023	169,187	150,987	97,764	120,386	79.7%	176.13	0	18,200	10.76%	12.05%
November-2023	168,210	146,830	94,316	118,139	80.5%	230.52	0	21,380	12.71%	14.56%
December-2023	110,803	107,659	57,718	97,435	90.5%	16.19	0	3,144	2.84%	2.92%
January-2024	127,328		69,106	115,255	90.5%	51.36	0	3,113	2.44%	
February-2024	120,373		63,319	104,752	87.0%	113.99	0	4,602	3.82%	
March-2024	117,684		60,153	105,834	89.9%	67.83	0	3,577	3.04%	
April-2024	131,855		69,075	107,323	81.4%	182.72	0	9,734	7.38%	
May-2024	119,326		64,040	105,351	88.3%	62.79	0	3,434	2.88%	
June-2024	114,049		57,385	99,978	87.7%	84.95	0	3,775	3.31%	
July-2024	125,305		64,175	106,965	85.4%	85.58	0	4,319	3.45%	
August-2024	114,682		63,429	97,371	84.9%	70.03	0	3,846	3.35%	
September-2024	116,563		62,735	92,197	79.1%	161.73	0	7,829	6.72%	
October-2024	140,102		76,045	108,382	77.4%	221.03	0	10,912	7.79%	
November-2024	114,954		59,287	95,038	82.7%	132.55	0	5,231	4.55%	
December-2024	108,736		54,180	99,193	91.2%	91.14	0	4,345	4.00%	
January-2025	125,343		63,321	113,702	90.7%	50.89	0	2,675	2.13%	
February-2025	126,497		61,037	104,853	82.9%	205.17	0	7,769	6.14%	
March-2025	132,686		64,109	116,633	87.9%	108.44	0	5,770	4.35%	
April-2025	123,959		61,050	105,100	84.8%	166.10	0	5,861	4.73%	
May-2025	121,248		59,862	103,839	85.6%	119.14	0	4,784	3.95%	
June-2025	109,785		58,087	96,777	88.2%	60.62	0	3,212	2.93%	
July-2025	116,951		62,746	105,818	90.5%	46.15	0	3,827	3.27%	
August-2025	119,995		64,746	104,635	87.2%	71.76	0	4,703	3.92%	
September-2025	119,178		65,521	105,275	88.3%	66.53	0	5,039	4.23%	
October-2025	146,017		78,587	112,251	76.9%	226.29	0	13,979	9.57%	
November-2025	113,791		58,338	90,644	79.7%	183.20	0	8,546	7.51%	
December-2025	114,758		58,574	104,136	90.7%	78.95	0	4,797	4.18%	
January-2026	121,912		62,568	109,992	90.2%	50.72	0	3,923	3.22%	

UGI UTILITIES, INC.
Annual Call Center Performance
Calendar Years 2023, 2024, 2025 and 2026

Calendar Year	Calls Received	Answer by Agent	Calls within 30 sec.	Average Speed of Answer (sec.)	Busy Out	Abandoned %
2023	1,807,421	1,002,629	82.4%	199.20	0	7.84%
2024	1,450,957	762,929	85.5%	110.48	0	4.39%
2025	1,470,208	755,978	86.1%	115.27	0	4.74%
2026*	121,912	62,568	90.2%	50.72	0	3.22%

*Through January 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Barbara R. Alexander, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 5SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: */s/ Barbara R. Alexander*
Barbara R. Alexander

Address: Barbara Alexander Consulting LLC
44 Beech Street
Hallowell, ME 04347

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

Direct Testimony of Roger Colton

on behalf of

Pennsylvania Office of Consumer Advocate

OCA Statement 6

Date Served: April 13, 2026

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger D. Colton. My business address is 34 Warwick Road, Belmont, MA, 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I own the firm Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations, and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of Rhode Island, New Jersey, Maryland, Pennsylvania, Ohio, Illinois, Wisconsin, Minnesota, and Missouri. My clients include state agencies (*e.g.*, Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Massachusetts Office of Attorney General), federal agencies (*e.g.*, the U.S. Department of Health and Human Services), community-based organizations (*e.g.*, Cleveland Legal Aid Society, Legal Action of Chicago, Consumers Council of Missouri), and public and private utilities (*e.g.*, Toledo Water, Xcel Energy, BC Hydro). Examples of my work include assisting the Connecticut Office of Consumers Counsel (OCC) in the annual generic review of the

low-income affordability initiatives of that state's utilities by the Public Utilities Regulatory Authority. I also assisted the Massachusetts Attorney General's Office (AGO) in the generic investigation by the Department of Public Utilities (DPU) into the design of low-income affordability programs. In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, I have completed a project with the Natural Resources Defense Council to develop a tool by which to assess the financial impact of differing types of low-income bill assistance. A brief description of my professional background is provided in Attachment RDC-1.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I received my law degree in 1981 (University of Florida). I received my Master's Degree (Regulatory Economics) from the MacGregor School of Antioch University in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A summary of my publications is included in Attachment RDC-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania PUC on numerous occasions regarding utility issues affecting low-income customers and customer service. My testimony has specifically included testimony in various proceedings involving low-income program design and operation, along with various rate design issues as they affect low-income customers. Overall, I have testified in regulatory proceedings in 43 states (other than Pennsylvania) and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified is presented in Attachment RDC-1.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is to review the impact of UGI Gas (UGI Gas or Company) rates on low-income customers. More specifically, I will examine the following topics:

- The overall affordability of the rates for current service of UGI Gas;
- How to enhance the identification of low-income customers;
- The efficiency and effectiveness of UGI Gas credit and collection expenditures;
- The need for and measures to improve the identification of low-income customers and enrollment of those customers in the Company's CAP;
- The need for UGI Gas' compliance with PUC regulations exempting low-income customers from cash security deposits; and
- The need for restraints on the collection and retention of customer Social Security Numbers by UGI Gas.

Summary of Recommendations

Q. CAN YOU PLEASE SUMMARIZE THE RECOMMENDATIONS YOU MAKE IN YOUR TESTIMONY BELOW?

A. Based on the data and discussion I present below, I make the recommend the following:

1. In the event that OCA's recommendation that the UGI Gas rate request be denied in its entirety, that UGI Gas adopt a more aggressive policy of extended "stay-outs" between base rate case filings. Repeating the filing of one rate case on top of another in short order is not in the best interests of ratepayers.

2. That there be a fifty-fifty sharing of the credit and collection expenses which UGI Gas proposes to include in its cost of service. This adjustment is dollarized and explained in more detail in the direct testimony of OCA witness Jennifer Rogers.

3. That UGI Gas, at a minimum, accept either a printout or a screenshot of the State of Pennsylvania's COMPASS application as adequate documentation to establish Confirmed Low-Income status.

4. That Confirmed Low-Income customers who are negotiating a deferred payment agreement (DPA) with the Company, as well as customers from whom the Company receives information placing them in an income tier of 0% to 150% FPL, should be provided a stand-alone written Plain Language notice informing those customers of their right, in the alternative, to enroll in the Company's Customer Assistance Program (CAP) (along with an explanation of the advantages of CAP's arrearage forgiveness provisions).

5. That UGI Gas be directed to modify its processes and procedures regarding the low-income exemption from deposits. UGI Gas should be directed to accept ***any*** information beyond information on income and household size that would "attest to" the household's eligibility for a state benefit that is consistent with CAP income requirements. Use of COMPASS information as described above should be included in that acceptable information.

6. That UGI Gas be directed to eliminate the requirement that a customer must apply for CAP in order to establish their eligibility for a deposit exemption.

7. That within three months of a final order in this proceeding, and every three months thereafter, UGI Gas undertake a review of the cash security deposits it currently holds, and report the results of such review to interested stakeholders in this proceeding.

8. That UGI Gas be directed to develop and adopt, within 12-months after a final order in this proceeding, an alternative to the use of SSNs.

9. That UGI Gas be directed to provide its Low-Income Advisory Committee regular three month reports on the operation and effectiveness of its Low-Income Customer Assessment and Outreach Pilot.

Part 1. Assessing the Affordability of UGI Gas Rates.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the affordability of UGI Gas bills for current service. I consider bill affordability from four different perspectives. First, I examine the history of rate increases for UGI Gas since 2016 and compare those increases to the changes in the income of low-income households during that same time period. Second, I examine bill affordability to low-income customers in particular. Third, I examine bill affordability to more moderate-income customers. Fourth, I examine the lack of resources available to low- and moderate-income customers to respond to the volatility in UGI Gas bills over time.

A. UGI Gas Rates Over Time.

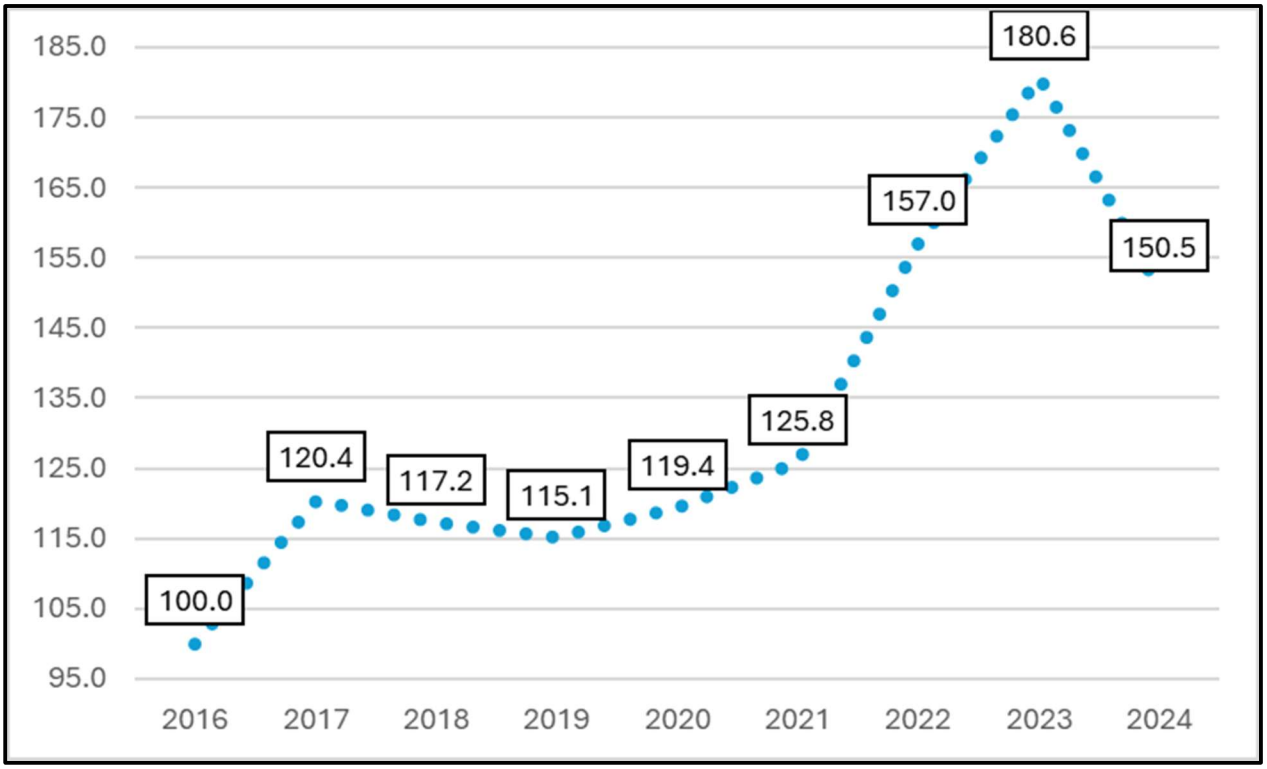
Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the impact of the changes in rates for UGI Gas from 2016 through 2024.[1] I determined the average residential revenue per therm by dividing the total residential revenue reported by UGI Gas in its Annual Report to the

[1] By starting in 2019, I begin before COVID.

Pennsylvania Commission by the total residential sales. I track the changes in UGI Gas rates through the calculation of a "Price Index." In calculating that Price Index, I assign 2016 a base case value of 100. The changes from that base case value represent the rate by which the values increased or decreased. Creating an index such as this is a common way to measure changes in prices. It is, for example, the way that the U.S. Bureau of Labor Statistics presents the rate of inflation.

Figure 1. UGI Gas Price Index (2016 – 2024)



The data in the Figure above shows that increases in UGI Gas rates have been substantial since 2020. While rates were relatively constant in the years 2017 through 2020, since 2020, there has been a sharp spike in the Company's prices. UGI Gas rates increased nearly 40% from 2020 through 2022 and more than 60% from 2020 through 2023. While they dipped somewhat in 2024, they remain well above 2020 levels. Notably, the Company has not even been able to fully account for or demonstrate the impacts of its

most recent rate increase, as those rates only went into effect for service rendered on and after October 28, 2025. The price hikes proposed in this proceeding will increase prices even further.

Q. ISN'T THE INCREASE IN PRICE PRIMARILY ATTRIBUTABLE TO INCREASES IN NATURAL GAS SUPPLY COSTS?

A. No. I have examined the PUC's "Rate Comparison Reports" for the years 2016 through 2025.[2] Those reports present the monthly bill for natural gas heating service at a usage of 15 MCF.[3] I examined both the bill for "distribution" costs and the "total" bill for UGI Gas. The Table below shows that the UGI Gas distribution bill has increased as a percentage of the total bill since the years 2016 through 2020. Even in 2022 and 2023, when the distribution price hikes were a smaller percentage, that occurred not because the distribution bill moderated but rather because the total bill spiked.

Table 1. UGI Gas: Distribution Monthly Bill vs. Total Monthly Bill (15 MCF)

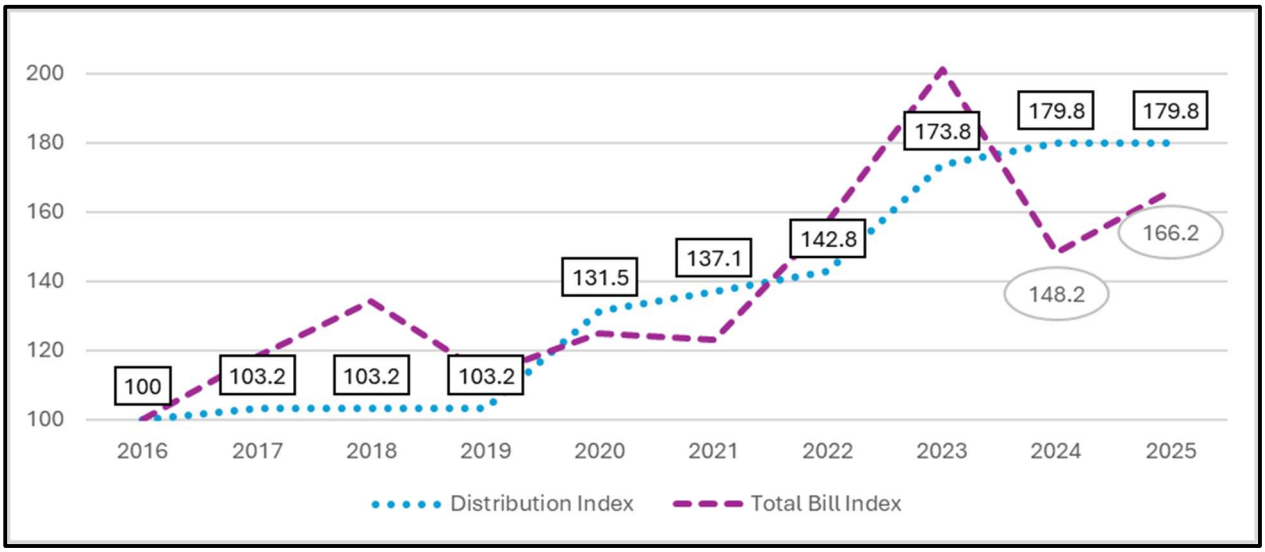
	Distribution Bill	Total Bill	Distribution as Pct of Total
2016	$43.18	$118.23	36.5%
2017	$44.58	$139.95	31.9%
2018	$44.58	$158.72	28.1%
2019	$44.58	$133.89	33.3%
2020	$56.79	$147.86	38.4%
2021	$59.20	$145.69	40.6%
2022	$61.66	$186.12	33.1%
2023	$75.04	$237.99	31.5%
2024	$77.65	$175.20	44.3%
2025	$77.65	$196.45	39.5%

[2] Available at https://www.puc.pa.gov/filing-resources/reports/rate-comparison-reports/

[3] In years prior to 2020, I use the rates for UGI Utilities – Gas Division as the rates for the Company. I do not consolidate the three UGI divisions in any way.

Calculating an Index for both the Distribution component of a UGI Gas bill since 2016 and the total UGI Gas bill for that same time period, as shown in Figure 2, since 2020, the UGI Gas distribution bill has increased faster than the UGI Gas total bill in every year but two (2022, 2023).

Figure 2. Distribution Bill Index and Total Bill Index (2016 – 2025) (UGI Gas)



The Figure above shows that while UGI Gas distribution bills have increased by 80% from 2016 to 2024 and 2025, UGI Gas total bills have increased by only 48% (2024) and 66% (2025).

Q. HAVE YOU EXAMINED HOW THE INCREASE IN UGI GAS PRICES COMPARES TO INCREASES IN THE INCOMES OF LOW-INCOME HOUSEHOLDS OVER THE SAME TIME PERIOD?

A. Yes. I compare the increase in UGI Gas bills from 2016 through 2024 as documented in the PUC's Rate Comparison Reports to the changes in the average First Quintile (Q1)

Income[4] for 353 of the 427 zip codes for which the Census Bureau reports income by Quintile in both 2026 and 2024.[5] Using the Total Bill Index of 166.2, it is evident that the incomes of low-income households are falling further and further behind increases in UGI prices/bills. Table 2 below shows that of the 353 UGI Gas zip codes for which Q1 income is published, only one-in-seven (n=51) experienced an increase in the Q1 Income Index of 165.5 or more (roughly equal to the Total Bill Index of 166.2). In contrast, 31 zip codes had a Q1 Index of less than 100, indicating that incomes actually declined during the same time period UGI bill increased by 65%. An additional 137 zip codes experienced an increase in income during this time period, but an increase of only 30% or less (i.e., an index of 100.5 – 130.5).

As with the Total Bill Index, the Q1 Index sets the base year (in this instance, 2016) equal to 100. The Index then documents the percentage change in the dollar value over time relative to that base year. A Q1 Index of "100"in 2024 would mean there was no change in the First Quintile (Q1) incomes from 2016 to 2024. A Q1 Index of 125 (for example) in 2024 would mean that the First Quintile incomes in 2024 were 25% higher in 2024 than they were in 2016. A Q1 Index of 80 (for example) in 2024 would mean that the First Quintile incomes in 2024 were 20% lower in 2024 than they were in 2016. In sum, an Index of less than 100 means that the value decreased relative to the base year, while an Index of more than 100 means that the value increased relative to the base year.

[4] The Census Bureau rank orders all households by income from lowest to highest. It then divides that ranking into five equal parts, each part of which is called a "quintile." The one-fifth of households with the lowest income is the "First Quintile" (Q1), sometimes known as the "lowest quintile." The one-fifth of households with the highest income is the "Fifth Quintile" (Q5).

[5] Some zip codes have sufficiently small populations that the Census Bureau does not report income by quintile due to privacy concerns.

If the Index is calculated for two different values are being compared (in this instance, UGI Gas Bills and Q1 Income), the significance is that the Index with the higher value increased the most.

Table 2. Count of UGI Gas Zip Codes by Index of Changes in First Quintile Income (2016 – 2024)[6] (Index of 100 means no change)

Q1 Income Index (2024 vs. 2016)	Count of UGI Gas Zip Codes
40.5-100.5	31
100.5-130.5	137
130.5-140.5	52
140.5-150.5	37
150.5-155.5	25
155.5-160.5	14
160.5-165.5	6
165.5-170.5	5
170.5-180.5	13
180.5-190.5	11
190.5-200.5	7
200.5 or more	15
Grand Total	353

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion I present below, I recommend that UGI Gas adopt a policy of aggressively pursuing more extended "stay-outs" between base rate case filings. Repeating the filing of one rate case on top of another in short order is not in the best interests of ratepayers.

B. The Unaffordability of UGI Gas Bills to Low-Income Customers.

[6] Changes in income are available only through 2024. Census data for 2025 has not yet been published.

Q. HAVE YOU EXAMINED THE AFFORDABILITY OF UGI GAS BILLS TO LOW-INCOME HOUSEHOLDS IN PARTICULAR?

A. Yes. The difference in the spiraling UGI Gas rates and the changes in the incomes of low-income households ultimately leads to consistently unaffordable UGI Gas burdens to low-income customers throughout its service territory. At an affordable burden of 4% for natural gas, a UGI Gas customer receiving the average bill of $1,010 in 2024[7] would have required an income of $25,250. Of the 427 UGI Gas zip codes for which Q1 incomes are reported for 2024, fewer than one-in-five (n=83) had a Q1 income that would have resulted in an affordable UGI Gas bill. The rate hike sought in this proceeding, of course, would increase bills (and thus increase the income needed to have an affordable burden) even further.

Q. HAVE YOU BEEN ABLE TO EXAMINE THE DISTRIBUTION OF INCOME IN THE TOTAL UGI GAS POPULATION IN ADDITION TO THE LOWEST QUINTILE OF INCOME?

A. Yes. I have examined the distribution of UGI Gas burdens for households with income less than $30,000 in the UGI Gas service territory. Nearly one-in-five (17.4%) households in the UGI Gas service territory have annual income less than $30,000. Households with income at or below $25,000 would have experienced a natural gas burden of more than 4%, while households with income between $25,000 and $30,000 would nearly reach that 4% limit of affordability.[8]

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[7] UGI Gas Annual Report to PUC, at Schedule 600, page 43.

[8] In Pennsylvania, the Commission specified its definitions of an "affordable burden." Pennsylvania PUC, Final Policy Statement and Order, at page 4, 2019 Amendments to Policy Statement on Customer Assistance Program, 52

Table 3. Distribution of UGI Gas Zip Codes by Average Q1 Incomes (2024)	
Average Q1 Income	Count of UGI Gas Zip Codes
$9,500 or less	13
$9,500 - $17,500	120
$17,500 - $23,500	115
$23,500 - $25,499	22
>$25,500	83
Grand Total	427

It would be incomplete, however, to simply consider income at $30,000 without considering the households falling in the "or below" part of the phrase. Households with income less than $10,000 would experience a UGI Gas burden (at 2024 bills) of more than 20% of income, while households with income between $10,000 and $15,000 would have experienced a UGI burden of more than 8%, twice the demarcation of affordability.

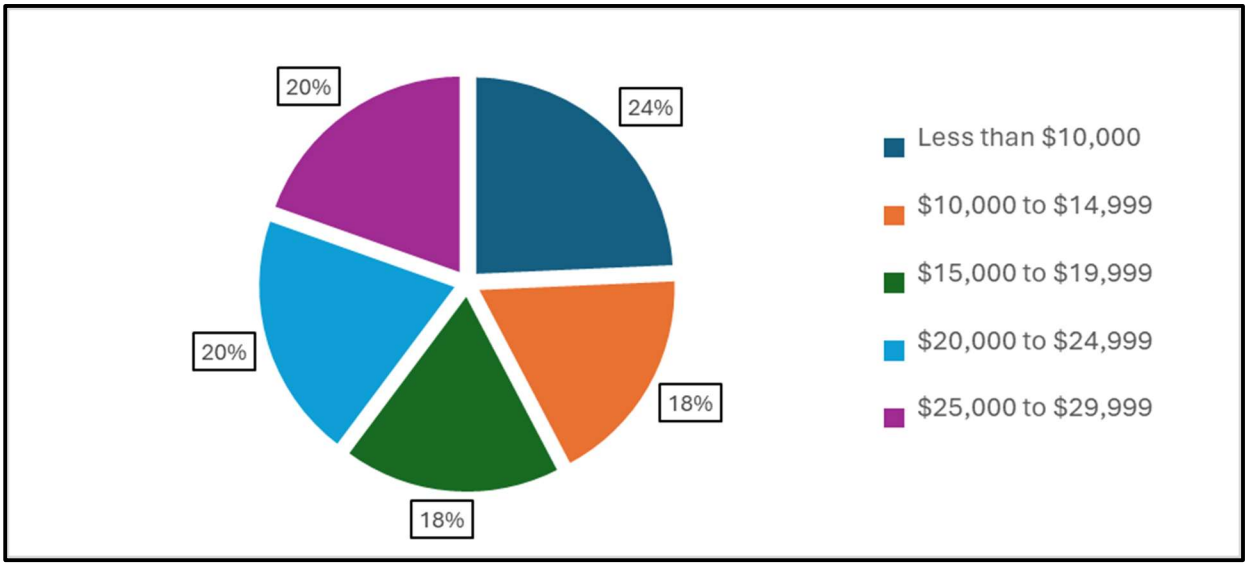
Pa. Code § 69.261–69.267, M-2019-3012599 (September 19, 2019). I choose the 4% burden prescribed by the PUC for households at or below 50% of Federal Poverty Level since that income level most closely aligns with Q1 incomes. The affordable burdens were prescribed after an extensive inquiry into the impacts of unaffordable bills, including payment impacts and household impacts associated with inability-to-pay. In deciding upon specific burdens, the Commission further balanced the adverse impacts on low-income households against the rate impacts of providing CAP subsidies to achieve the affordable burdens.

Table 4. UGI Gas Burdens at 2024 Residential Bill of $1,010 at Annual Income Below $30,000

Income Range	Income Mid-Point	Burden at 2024 Bill of $1,010
Less than $10,000	$5,000	20.2%
$10,000 - $14,999	$12,500	8.1%
$15,000 - $19,999	$17,500	5.8%
$20,000- $24,999	$22,500	4.5%
$25,000 - $29,999	$27,500	3.7%

Figure 3 below shows that of the UGI Gas population with annual income less than $30,000, nearly one-quarter (24%) in fact have income less than $10,000. More than four-of-ten (24% + 18% = 42%) have income less than $15,000, with a UGI Gas burden two times higher than the affordable burden of 4%.

Figure 3. Distribution of Households with Annual Income Below $30,000 by Income



When the data above is read together in its entirety, it is clear that UGI Gas has a significant rate affordability problem even before taking into account the increase in rates sought by the Company in this proceeding.

Q. IN ADDITION TO THE UNAFFORDABILITY OF UGI GAS BILLS, PLEASE DESCRIBE THE IMPACT OF INFLATION ON LOW-INCOME CUSTOMERS.

A. In addition to examining the specific unaffordability of UGI Gas rates to low-income households, I also examine the disproportionate adverse impact that inflation has on low-income customers.

The process of setting reasonable rates does not exclusively consider the interests of the utility and its investors. The courts, for example, have noted that setting a reasonable return on equity must involve a balancing of the interests of investors and ratepayers. In addition, under Pennsylvania law, in setting rates, the Public Utility Commission must give "due consideration to the interests of consumers."[9] To the extent that the impacts of inflation on investor interests are considered, therefore, the impacts of inflation on ratepayer interests must be considered as well.

Inflation is disproportionately affecting lower-income households. The Return on Equity (ROE) sought by the Company in this proceeding, which would have the impact of driving up rates, will exacerbate this problem. Given the PUC's obligation to balance the interests of investors and ratepayers in setting a reasonable ROE, the PUC should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.

[9] 71 Pa. Stat. Ann. §309-5(2).

Q. HOW DOES INFLATION HAVE A PARTICULARLY ADVERSE IMPACT ON LOWER INCOME HOUSEHOLDS?

A. The impact of inflation is felt most severely by low-income households. Research by the U.S. Department of Labor's Bureau of Labor Statistics,[10] reports that "consumers with different incomes experience inflation quite differently."[11] According to this research, the lowest earning households spend a disproportionately higher share of their household budget on household necessities such as rent, food and medical care.

Table 5. Household budget shares of expenditure items for lowest and highest income quartiles, 2017–2018[12]

Expenditure	Lowest Income Quartile	Highest Income Quartile
Rent (including owner's equivalent rent	34.93%	27.93%
Food at home	9.44%	6.58%
Medical care	8.36%	8.09%
Household utilities	4.36%	2.73%
Motor fuels	3.46%	3.42%
Motor vehicle operation	3.44%	3.40%
Telephone service	2.32%	2.00%

While low-income households pay more of their budgeted income for this basket of essential goods, it is also important to note that the BLS researchers found that, "prices for motor fuel, medical care, fuel and utilities, and shelter rose faster than the overall average.

[10] BLS is the agency that calculates and reports the "rate of inflation" (i.e., the Consumer Price Index [CPI]) each month.

[11] Klick and Stockburger (December 2022). Spotlight on Statistics: Inflation Experiences for Lower and Higher Income Households, U.S. Department of Labor, Bureau of Labor Statistics, available at https://www.bls.gov/spotlight/2022/inflation-experiences-for-lower-and-higher-income-households/home.htm

[12] Id.

. .”[13] Thus, “[b]ecause the lowest income households dedicate more of their spending on these categories,” the BLS researchers found, “their overall inflation rates grew faster than highest income households.”

Q. WHAT IMPACT DO INFLATION PRICES HAVE ON HOUSEHOLDS?

A. The Federal Reserve researchers found that the “stress” being placed on households by high inflation is much greater for low-income households as low-income households have fewer resources and fewer options to mitigate the impact of inflation. They explained:

> Prior research suggests that inflation hits low-income households hardest for several reasons. They spend more of their income on necessities such as food, gas and rent—categories with greater-than-average inflation rates—leaving few ways to reduce spending. When prices rise, middle-income households may react by consuming cheaper goods and buying more generic brands. Low-income households do not have the same flexibility; in many cases, they are already consuming the cheapest products.
>
> Additionally, many low-income households lack the ability of higher-income households to stock up when prices are discounted, buy in bulk and save, delay purchases if there is an opportunity to save in the future or buy more cheaply online. Low-income households are also likely to have smaller cash buffers to tide them over a period of high inflation.[14]

The data is clear and consistent. Lower income families expend a greater share of their income on necessities (which, as a whole, tend to have higher inflation rates); have smaller financial cushions to mitigate the impact of inflation; and may have less of an ability to switch to lower-priced alternatives. As Lael Brainard, a member of the Board of Governors

[13] Id.

[14] Jayashankar and Murphy (January 2023). High inflation disproportionately hurts low-income households, Federal Reserve Bank of Dallas, available at https://www.dallasfed.org/research/economics/2023/0110#:~:text=Low%2Dincome%20households%20most%20stressed,few%20ways%20to%20reduce%20spending%20.

of the Federal Reserve System, concluded, "All Americans are confronting higher prices, but the burden is particularly great for households with more limited resources."[15]

C. The Unaffordability of UGI Gas Bills to More Moderate Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the ability-to-pay of more moderate income households using the ALICE Threshold. "ALICE" is the acronym used to describe Asset-Limited, Income-Constrained, Employed ("ALICE") households, who have income above the Federal Poverty Level but below the cost of basics included in the ALICE Household Survival Budget described below.

Q. PLEASE DESCRIBE THE TERMINOLOGY YOU USE IN USING THE ALICE DATA.

A. There are three basic terms that are used in presenting and assessing ALICE data for a particular geographic area:

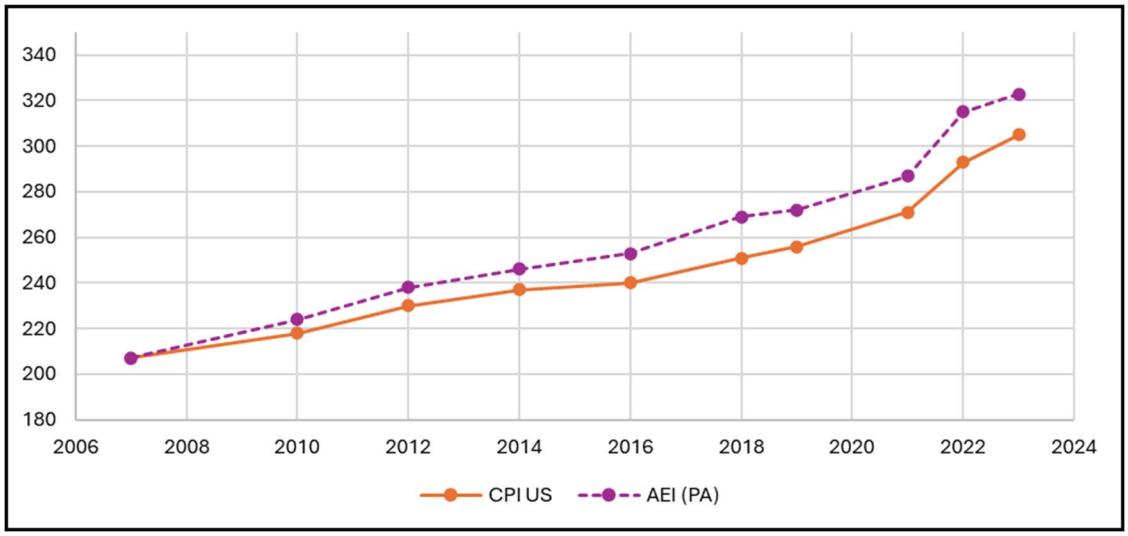
- **The ALICE Survival Budget**. The ALICE Survival Budget tracks the cost of household necessities that matter most to ALICE households: housing, child care, food, transportation, health care, and basic technology. According to United for ALICE, the United Way research arm which addresses the economic issues facing ALICE households, the ALICE Budget differs from the budget used by the U.S. Bureau of Labor Statistics (BLS) to calculate the Consumer Price Index (the traditional measure of inflation). The budget which BLS uses tracks over 200 goods and services. These include items that financially insecure households cannot afford on a regular basis (*e.g.*, full-service meals at restaurants, wine, major appliances, flights, and jewelry). In contrast, the ALICE Budget is limited to household essentials.[16]

[15] Brainard (April 2022). Variations in the inflation experiences of households, available at https://www.federalreserve.gov/newsevents/speech/brainard20220405a.htm

[16] ALICE Essentials Index, available at https://www.unitedforalice.org/essentials-index

- **The ALICE Essentials Index:** The ALICE Essentials Index is the rate of price increase for the limited market basket of household essentials: housing, child care, food, transportation, health care, and a smartphone plan. According to the 2025 ALICE report for Pennsylvania, the ALICE Essentials Index has consistently outpaced the broader CPI nationwide.[17] Nationally, the ALICE Essentials Index has outpaced the broader CPI nationwide since 2007. Between 2021 and 2023, the ALICE Essentials Index increased at an annual rate of 7.3% compared to 6.1% for CPI. The ALICE report for Pennsylvania reported that "in Pennsylvania, the ALICE Essentials Index also tended to increase faster than CPI. . ."

Inflation: Alice Essential Index (AEI) vs. Consumer Price Index (CPI) (Pennsylvania)



The Pennsylvania ALICE Report found that "[w]hile wages have risen substantially in recent years, so have costs. And even in occupations where wages are growing faster than costs, wages started from such a low level that many workers are still not able to cover household essentials."[18]

- **The ALICE Wage:** The ALICE Wage is expressed on a monthly, annual and hourly basis. The Alice Wage represents the dollar amount needed to be earned that would exactly equal the household's ALICE Survival Budget. A wage lower than the ALICE Wage means the wage-earner can *not* meet the ALICE Survival Budget. A wage higher than the ALICE Wage means the

[17] The State of ALICE in Pennsylvania: Costs Over Time: The ALICE Essential Index, https://www.unitedforalice.org/costs-over-time/pennsylvania

[18] Id.

wage-earner is meeting the ALICE Su15 rvival Budget with some additional earning capacity left over. The ALICE Wage differs by household size and composition, as well as by the number of wage earners in the household.

Q. HAVE YOU EXAMINED THE WAGES NEEDED TO MEET THE ALICE SURVIVAL BUDGET IN THE COUNTIES SERVED BY UGI GAS?

A. Yes. I have reviewed the ALICE Wage for a selection of UGI Gas counties representing a diversity in geographic locations. The counties I selected are the 15 UGI Gas counties with the largest populations of UGI Gas residential customers. As I described above, the dollars needed for a household to meet the ALICE Survival Budget is known as the ALICE Wage. The ALICE Wage for the UGI Gas counties I examine is set forth in Table 6 below.

Table 6 demonstrates how the cost-of-living varies across Pennsylvania. For example:

- Bucks, Lehigh, and Northampton counties have noticeably higher ALICE wages than do the other UGI Gas counties, followed closely by Lancaster.
- In contrast, Northumberland and Tioga counties have noticeably lower ALICE wages than do other counties.
- Overall, the ALICE Wage (for a one-adult, one child family) throughout these 15 UGI Gas counties differ by more than $8 per hour, from a low of $19.27 (Northumberland County) to a high of $27.74 (Bucks County).

It is evident from the data presented in the Table that the cost-of-living for these moderate income households, and thus the ability of these UGI Gas customers to absorb the rate increase sought in this proceeding, varies widely across the Company's service territory.

Table 6. Hourly Wage Needed to Meet ALICE Threshold (by Family Composition)
(15 Counties with Largest Number of UGI Gas Customers)

Name	Single Adult	One Adult One Child	One Adult One Childcare	Two Adults	Two Adults Two Children	Two Adults Two Childcare
Berks	$15.20	$22.51	$25.76	$22.64	$36.58	$43.40
Bucks	$19.15	$27.74	$32.29	$27.05	$43.61	$52.96
Columbia	$14.38	$21.62	$24.91	$21.76	$34.90	$41.81
Cumberland	$16.06	$23.55	$26.95	$23.60	$38.09	$45.91
Dauphin	$15.94	$23.35	$26.76	$23.38	$37.71	$45.59
Lackawanna	$14.71	$21.83	$24.85	$22.12	$35.38	$41.76
Lancaster	$16.53	$23.92	$26.98	$24.17	$38.42	$45.16
Lebanon	$15.38	$22.01	$25.44	$22.06	$36.26	$44.17
Lehigh	$17.33	$24.94	$28.41	$24.92	$39.97	$48.50
Luzerne	$14.71	$21.92	$25.20	$22.06	$35.57	$42.46
Lycoming	$14.83	$21.11	$23.58	$21.72	$34.09	$39.31
Northampton	$17.39	$25.17	$28.60	$25.18	$40.47	$48.91
Northumberland	$13.26	$19.27	$21.68	$19.90	$31.96	$36.97
Potter	$14.05	$20.10	$22.48	$20.77	$33.77	$38.87
Tioga	$13.39	$19.66	$22.13	$20.26	$32.78	$38.03

Q. HAVE YOU EXAMINED ANY SUBSET OF ALICE HOUSEHOLDS IN PARTICULAR?

A. Yes. The Table below documents what hourly wage would be required to meet the ALICE Survival Budget for *senior* households based on data up to 2023. As with the households discussed above, Bucks and Northampton counties also have the highest ALICE Wages for both a household with a single senior person, and a household with two seniors. Dauphin and Lancaster Counties also have relatively high wages required to meet the necessary household expenses for UGI Gas seniors.

Table 7. Hourly Wage Needed to Meet ALICE Threshold for Senior Households
(15 Counties with Largest Numbers of UGI Gas Customers)

Name	Single Senior	Two Seniors
Berks	$17.59	$27.91
Bucks	$21.53	$32.41
Columbia	$16.62	$26.75
Cumberland	$16.06	$23.55
Dauphin	$18.38	$28.78
Lackawanna	$16.78	$26.76
Lancaster	$18.50	$28.64
Lebanon	$17.46	$26.73
Lehigh	$17.33	$24.94
Luzerne	$16.87	$26.89
Lycoming	$16.90	$26.37
Northampton	$19.66	$30.28
Northumberland	$15.64	$25.15
Potter	$15.97	$25.09
Tioga	$15.14	$24.26

The ALICE wages are important to consider in this UGI Gas rate case given the high percentage of households who do not earn sufficient wages to meet the ALICE Survival Budget. Table 8 presents, for the same fifteen largest UGI Gas counties,[19] the percentage of households who live with an annual income below the ALICE Threshold. Potter, Luzern, and Columbia counties have 45% to 46% of households with incomes below the ALICE Threshold, while Lackawanna County has more than half of its households (51%)

[19] These 15 counties include 91.4% of all UGI Gas customers. CAUSE-PA-1-8.

with incomes below the ALICE Threshold. In addition, Berks (40%), Lancaster (40%), Lehigh (42%), Lycoming (43%), Northumberland (42%), and Tioga (42%) all have between 40% and 45% of their households earning insufficient income to meet the ALICE Threshold. None of the 15 counties with the largest UGI Gas customer base have fewer than 30% of their households failing to meet the ALICE Threshold.

Table 8. Percent Households Below ALICE Threshold
(15 Counties with Largest Number of UGI Gas Customers)

Name	Total Households	% Below ALICE Threshold
Berks	163,307	40%
Bucks	249,189	32%
Columbia	25,929	45%
Cumberland	107,981	36%
Dauphin	121,773	39%
Lackawanna	88,871	51%
Lancaster	211,669	40%
Lebanon	58,012	35%
Lehigh	147,524	42%
Luzerne	136,046	46%
Lycoming	46,849	43%
Northampton	123,536	39%
Northumberland	37,343	42%
Potter	6,757	45%
Tioga	16,639	42%

As is evident from this discussion, the unaffordability of UGI Gas bills is not a problem that inheres exclusively in the low-income population of UGI Gas. As demonstrated by the Census Bureau's Household Pulse Survey (HPS) discussed in detail below, the insufficiency of income is increasingly resulting in the inability to pay household utility

bills, or to pay such bills in full, by even more moderate-income customer base(see, Table 10, supra). In addition to this inability-to-pay, however, the HPS documents that even more moderate income Pennsylvania households are also being forced to engage in dangerous efforts to reduce their energy bills when they find that they cannot afford to pay these bills. The cells in Table 9 below show that even households with income between $35,000 and $75,000, well above 50% of Federal Poverty Level, have been forced to make trade-offs in order to pay their utility bills. Indeed, only 68% to 77% of households with income between $50,000 and $150,000 report "never" needing to make such tradeoffs.

Table 9. Household reduced or forwent expenses for basic household necessities, such as medicine or food, in order to pay an energy bill (HPS, Housing Table 4)

	Almost every month	Some months	1 or two months	Never	Total
Less than $25,000	13.3%	26.3%	15.1%	44.1%	98.8%
$25,000 - $34,999	15.6%	12.4%	8.6%	63.4%	100.0%
$35,000 - $49,999	14.6%	15.7%	11.1%	58.5%	100.0%
$50,000 - $74,999	7.1%	20.4%	4.3%	68.3%	100.0%
$75,000 - $99,999	3.5%	14.4%	7.7%	74.3%	99.9%
$100,000 - $149,999	3.6%	7.2%	12.3%	77.0%	100.0%
$150,000 - $199,999	5.2%	3.1%	1.4%	90.3%	100.0%
$200,000 and above	1.9%	0.0%	5.4%	92.7%	100.0%

Again, the problems that arise as a result of the increasing unaffordability of UGI Gas bills for more moderate income UGI Gas households will be exacerbated even further by the rate hike sought by UGI Gas in this proceeding.

D. The Lack of Household Resources as Contributing to the UGI Gas Affordability Problem.

Q. IS THERE AN ADDITIONAL HOUSEHOLD ATTRIBUTE THAT CONTRIBUTES TO THE UNAFFORDABILITY OF UGI GAS BILLS?

A. Yes. It would be a mistake to focus attention exclusively on household income in an examination of the affordability of UGI Gas bills. In addition to looking at household income, an examination of the affordability of UGI Gas bills should also consider the availability of household resources. When I reference household resources in this respect, I am referring to the availability of liquid assets that would allow a customer of UGI Gas to respond to large variations in either seasonal or annual bills. To the extent that a household lacks such resources, there will be an inability to respond to changes in annual or seasonal bills. My reference to a "liquid resource" is a reference, primarily, to the lack of an adequate banking or saving account from which a customer can draw dollars in order to pay a higher UGI Gas bill.

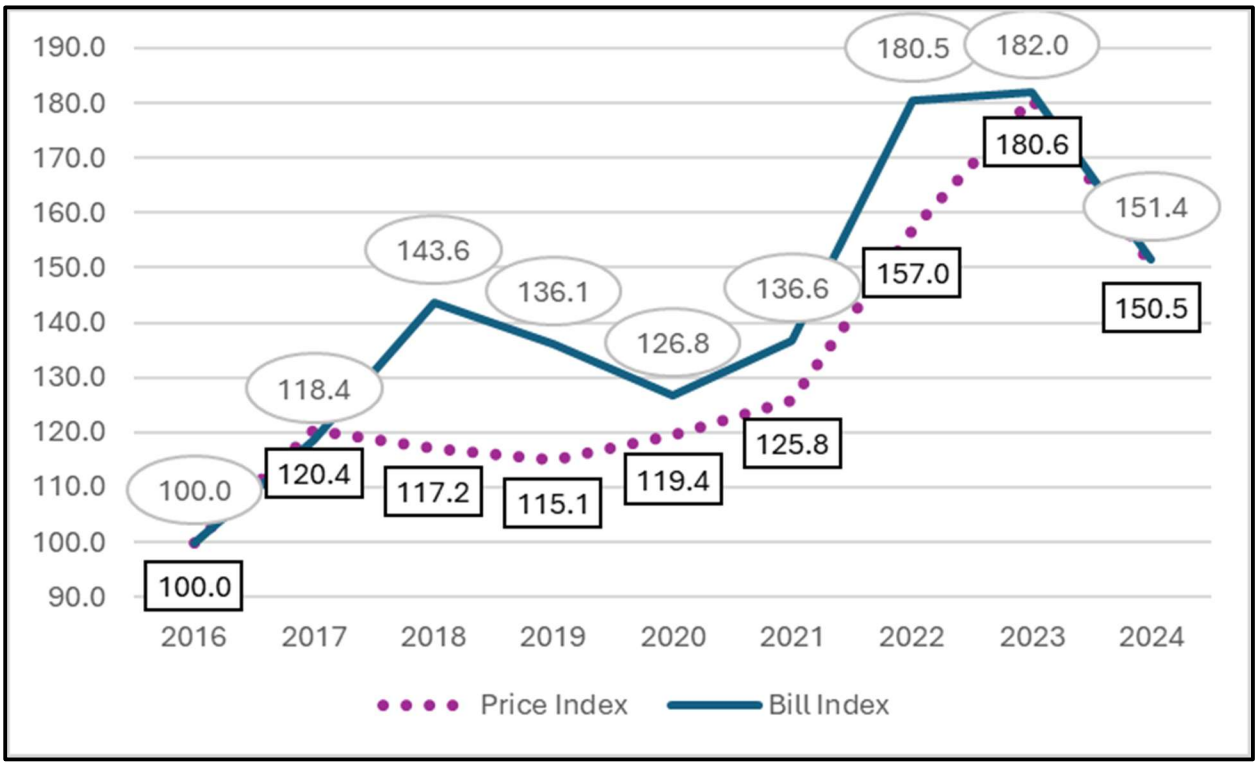
Q. HAVE UNEXPECTED CHANGES IN ANNUAL BILLS OCCURRED FOR UGI GAS CUSTOMERS?

A. Yes. Figure 4 presents a comparison of the changes in UGI Gas prices relative to the changes in average annual UGI Gas bills for the years 2016 through 2024. While the Figure shows, as discussed in detail above, the recent spike in UGI Gas prices to residential customers, the importance for purposes here is a comparison of the relative changes in prices and bills. Even in years when prices declined, UGI Gas customers could face increased bills due to the need for increased consumption. From 2017 to 2018, for example, while the Price Index declined (from 120.4 to 117.2), the Bill Index saw a

substantial increase (from 118.4 to 143.6), largely due to the fact that average residential consumption in 2017 was 71 MCF while the average residential consumption in 2018 was 88 MCF. Prices remained relatively steady in 2019 (Price Index of 115.1), but the Bill Index remained high (136.1) because average residential consumption in 2019 remained high (85 MCF). Similarly, while prices increased substantially from 2021 to 2022 (from a Price Index of 125.8 to a Price Index of 157.0), bills increased even more (from a Bill Index of 136.6 to a Bill Index of 180.5). This occurred because annual residential usage jumped to 82 MCF in 2022, before moderating back to 72 MCF in 2023 and 2024.

As is evident, it is not merely the size of the UGI Gas bill that poses a problem for customers. The year-to-year volatility in UGI Gas bills pose particular problems to households who lack the resources to set aside an "emergency fund" to respond to these unexpectedly high expenses. The volatility cannot be prevented by investing in energy efficiency measures. Due to the very fact of their poverty, low-income households lack the discretionary income to invest even in cost-effective efficiency measures. As documented in Table 9 and Table 10, low-income Pennsylvania households are having difficulties in paying their bills with which to begin, as well as being forced into tradeoffs between utility bill payment and payments for other household necessities; they lack the resources to make investments with an uncertain future return. Moreover, since low-income UGI Gas households tend most frequently to be tenants, they lack the authority to make decisions regarding the major gas-consuming systems in their homes (what is known as "dominion interest," the authority to make decisions), even if they had the financial wherewithal to do so.

Figure 4. Bill Index Compared to Price Index (2016 – 2024)



Q. IS THERE A SEASONAL VARIATION IN UGI GAS BILLS THE RESPONSE TO WHICH MAY BE IMPEDED BY THE LACK OF HOUSEHOLD LIQUID RESOURCES?

A. Yes. In addition to there being unexpected annual variations in UGI Gas bills, there are seasonal variations in UGI Gas bills as well that can be demonstrably shown to be associated with higher unpaid bills. In my discussion below, I consider both the changes in mean *monthly* usage/bills/arrears and the changes in *median* monthly usage/bills/arrears and explain the significance of the difference between those two results.

Figure 5 below begins with a presentation of the median monthly residential usage, median monthly bills, and median monthly arrears for the time period October 2023

through January 2026. The "median" is the point at which half of all accounts have higher values and half of all accounts have lower values. In other words, the "median" is the middle. I begin the data set in October in order to keep complete winter heating seasons together, and continue through the most recent data which UGI Gas has available at the time I write this testimony (January 2026).

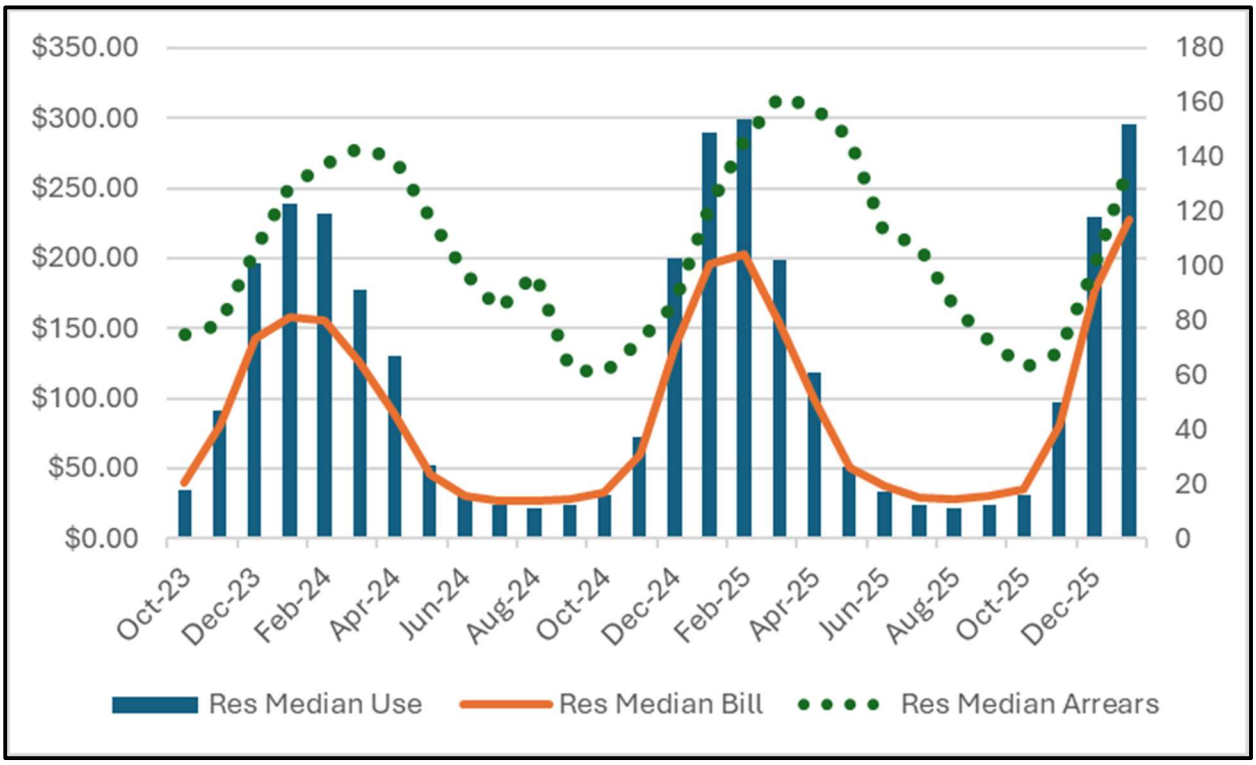
The data presented in Figure 5 below supports four important observations for purposes here.

- First, not surprisingly, as a natural gas utility, UGI Gas is seen as having a substantial variation in its monthly bills. As heat-related median consumption increases in the winter months (i.e., the bars), the median bills increase correspondingly.
- Second, the Figure shows that as bills increase on a monthly basis, median arrearages increase as well. As would be expected, the level of arrearages lags the bills by a month. A higher December bill, in other words, is reflected in a higher arrears in January; a higher January bill is reflected in a higher arrears in February. This impact is seen going both ways. As bills decline in the warm weather months, the level of arrears can be seen to decline as well. The lower usage, and thus the lowest bills, are seen in the warm weather months, and the median arrears decline further in each of those months.
- Third, it is evident that despite higher levels of cold weather arrears, those arrears get paid down in warm weather months. Going into the 2023/2024 winter season, arrears are moving from a lower amount in October 2023 to higher levels in the cold weather months. The higher median arrears in the

2023/2024 winter heating season get reduced in the warm weather months of 2024, while the higher median arrears in the 2024/2025 winter heating season get reduced in the warm weather months of 2025.

- Fourth, it is evident that the cold weather arrears that are paid off are not limited to the smaller amounts of arrears. If there were a population of customers with arrears, and only the smaller arrears were subsequently being retired, the median would actually *increase*. The fact that the median arrears declines in the warm weather months in a pattern consistent with bills (and usage) demonstrates that arrears are being retired across the full spectrum of balances high-to-low. This happens as a matter of arithmetic. Assume that you have seven numbers: 1, 3, 5, 7, 11, 17, 19. The median is 7. If you were to eliminate the two smallest numbers (1, 3), the median of the remaining numbers would increase to 11.

Figure 5. Median Monthly Residential Usage, Bills and Arrears (October 2023 – January 2026)[20]



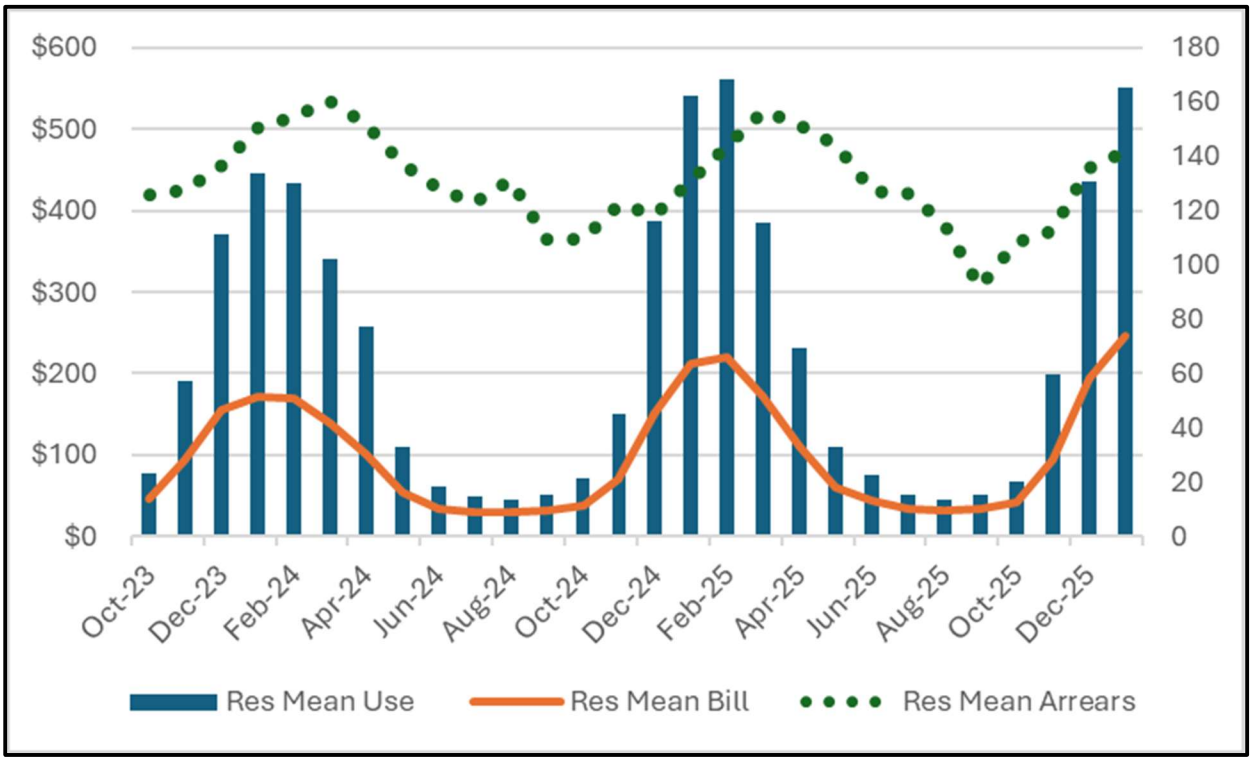
In contrast to the data above, Figure 6 shows the data for the same time period, but instead of looking at the median (i.e., the middle), it looks at the mean (average) data. The obvious observation from an examination of this data is that the pattern of mean monthly usage, bills, and arrears follows the same pattern as the pattern of median monthly usage, bills, and arrears.

Figure 6 When compared to Figure 5, Figure 6 shows that UGI Gas has a significant number of residential customers who incur high consumption, have correspondingly high bills, and have even higher arrearage balances. When the mean of a population is substantially higher than the median, that indicates that the population has a "right skew"

[20] OCA-4-7, OCA-4-9, OCA-4-11.

(i.e., a significant number of accounts with higher values). That "right skew" occurs for arrearages in particular. While the *mean* arrears ranges between $300 and $500 (Figure 6), for example, the *median* arrears ranges between $150 and $300 (Figure 5). While the mean bill ranges

Figure 6. Mean Monthly Residential Usage, Bills and Arrears: October 2023 – January 2026)[21]



Unless UGI Gas addresses the volatility in monthly bills, the Company places at risk substantial seasonal billings. Figure 7 shows the mean and median arrears by month for the period October 2023 through January 2026.

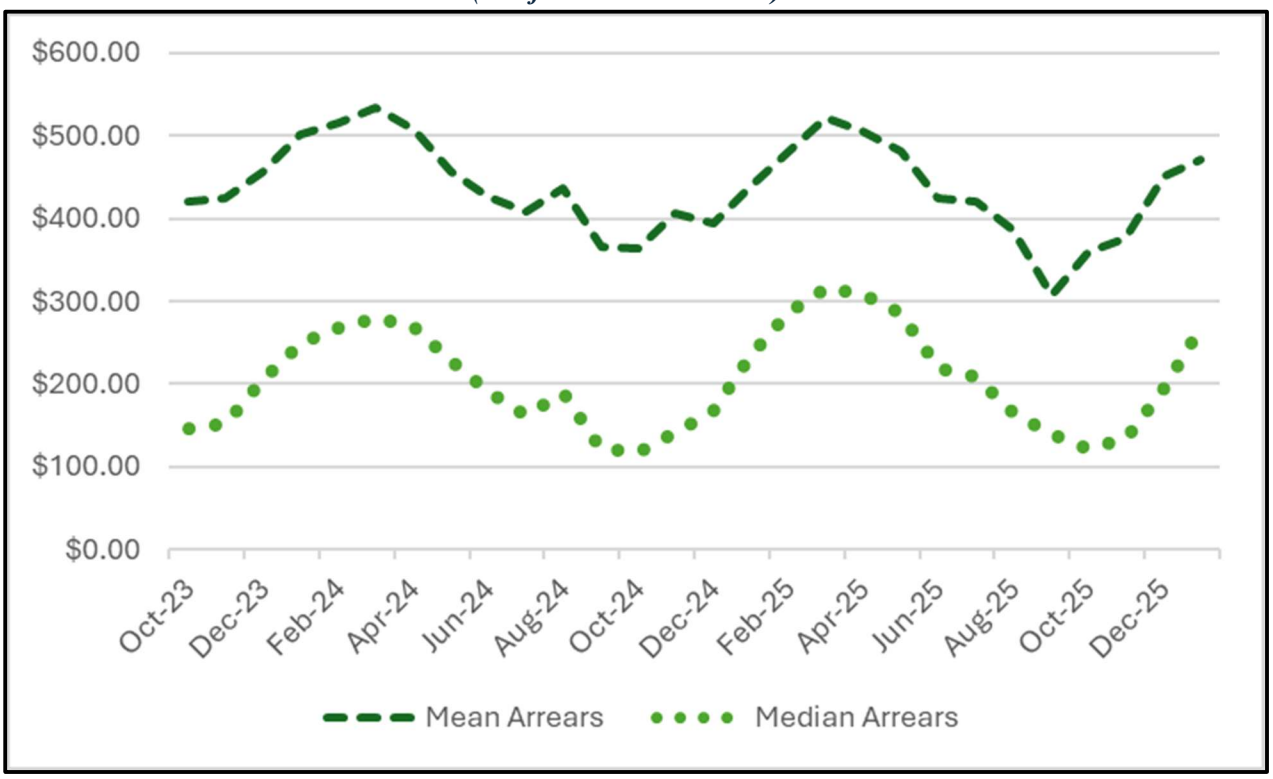
The data in the Figure provides important insights into the affordability of UGI Gas bills to both low- and moderate-income households, when affordability is viewed not merely

[21] OCA-4-6, OCA-4-8, OCA-4-10.

from the perspective of "income" but from the perspective of "resources" as well. The Figure supports several observations:

- There is a population of low-income customers for whom the lack of resources, as well as income, will make it highly unlikely that their past-due account balances can or will be retired. Given a monthly arrearage balance consistently in excess of $400, low-income customers lack the liquid resources to be able to respond to these unpaid bills.
- As discussed above, the fact that the mean is substantially higher than the median demonstrates that there the distribution of low-income customers with arrears is skewed toward a high incidence of customers with higher-than-average arrears. In the absence of enrollment in CAP, these customers would be required not only to pay their past-due balances, but required also to pay their full current bills over and above retiring their arrears. Increasing bills for current service even higher, as would result from the rate increase requested in this proceeding, would make the required total bill payment even that much less attainable.

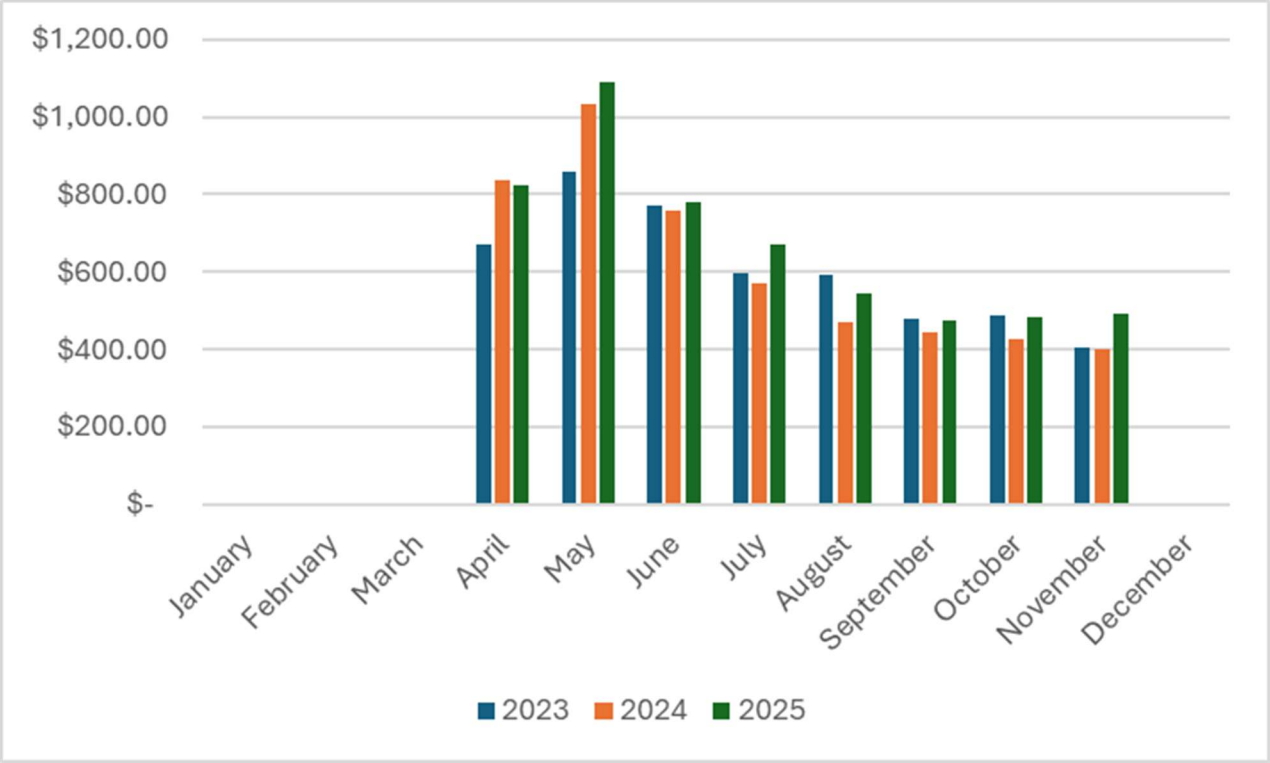
Figure 7. Difference Between Monthly Mean Arrears and Monthly Median Arrears (Confirmed Low-Income)



Failing to identify and recognize the inability-to-pay due to a lack of resources to respond to the monthly volatility in bills, is not merely a failure to identify payment problems from the perspective of the customer (as I have discussed in detail above), but it also represents a serious increase in the financial risk to UGI Gas. Figure 8 shows the increasing balances owed by Confirmed Low-Income customers at the time of a nonpayment disconnection.[22] As the 2025 rate hikes are passed through in higher winter bills, combined with future rate increases (if any) associated with the rates which UGI Gas proposes in this proceeding, it is reasonable to expect that these dollars lost at the time of disconnection will continue to get higher and higher.

[22] OCA-4-23(b).

Figure 8. Average Arrears at the Time of Disconnection (Confirmed Low-Income)[23].



Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT UNPAID HOME HEATING BILLS CAN BE ATTRIBUTED, IN PART, TO THE LACK OF LIQUID RESOURCES THAT SERVE AS A CUSHION AGAINST INCREASES IN ANNUAL OR MONTHLY BILLS?

A. The first foundation of my conclusion lies with Pennsylvania data reported in the Census Bureau's 2023 Household Pulse Survey (HPS). While the HPS does not provide data specific to utility service territories, it does provide information specific to Pennsylvania. The HPS documents that Pennsylvania households frequently have difficulties in paying

[23] Given PUC regulations, UGI Gas does not disconnect service to Confirmed Low-Income customers during the cold weather months of December through March. Hence, this figure shows no average arrears at the time of disconnection since there are no disconnections.

their utility bills. When they face such difficulties, low-income households lack the resources to respond to the unaffordability of bills.

The Table below documents that, in Pennsylvania, from 20% to more than 30% of households with income less than $75,000 reported being unable to pay an energy bill, or unable to pay the full bill amount, either "almost every month" or in "some months." The utility bill payment difficulties facing Pennsylvania customers are simply not confined to the lowest income tier. As incomes increase, the reported inability-to-pay declines.

Table 10. Household was unable to pay an energy bill or unable to pay the full bill amount

	Almost every month	Some months	1 or two months	Never	Did not report
Less than $25,000	7.8%	11.5%	23.4%	56.6%	99.3%
$25,000 - $34,999	15.6%	11.6%	5.0%	67.9%	100.0%
$35,000 - $49,999	14.5%	18.3%	7.6%	59.6%	100.0%
$50,000 - $74,999	2.7%	17.1%	6.1%	74.1%	100.0%
$75,000 - $99,999	2.5%	4.5%	11.6%	81.4%	100.0%
$100,000 - $149,999	3.4%	2.6%	6.6%	87.5%	100.0%
$150,000 - $199,999	4.8%	1.8%	2.7%	90.6%	100.0%
$200,000 and above	0.0%	2.1%	2.2%	95.7%	100.0%

Assuming this data reflects UGI's service territory, it is reasonable to conclude that nearly three-of-ten UGI Gas residential customers in 2024 (more than 197,000) could not pay the full bill, in almost every, some, or one or two, months.[24]

[24] UGI Gas had 630,288 residential customers in 2024. BCS 2024 Annual Report, at page 5. Applying HPS data to this number, 31.3% could not pay their home energy bill, or could not pay the full bill, in almost every, some, or one or two, months. Nonetheless, since that time, UGI Gas sought and received a rate hike in 2025 and is seeking yet another rate hike in 2026.

The question here, however, is the degree to which, if at all, a lack of resources contributes to this inability to pay. In 2023, the HPS inquired into what resources households turned to "meet their spending needs in the last seven days." The HPS tracked responses by income. I examined these resources for households with income less than $25,000 for eight time periods, four which were in cold weather months and four of which were in warm weather months. The data shows:

- In all eight months, households in the lowest income bracket had the lowest percentage of households able to meet their spending needs out of "regular income sources." With one exception, roughly six-of-ten of these low-income households could meet their spending needs with regular income sources.

- These low-income households did not have assets or "money from savings" to help them meet their spending needs. In the "week"[25] with the greatest use of selling assets or using money from savings, only 25% of low-income households were able to do so. In seven of the eight periods, only households with income of $200,000 or more used their savings, or sold assets, to meet spending needs, but for this income range, between 95% and 97% of households reported meeting their spending needs out of regular income.

- Borrowing from friends or family was the most common method used by low-income households to meet spending needs when the regular income sources were not available or sufficient. Consistently between one-quarter and nearly

[25] While the HPS labels each survey period a "week," each survey actually covered a two-week period.

one-third of low-income households relied upon such loans from friends or family.

Table 11. Methods Used to Meet Spending Needs in Last Seven Days
(Income <$25,000)
(Census Household Pulse Survey) (2023)

Time Period	Regular Income Sources	Money from Savings or Selling Assets	Borrowing from Friends or Family
Week 52 (12/9-12/19)	59%	23%	29%
Week 53 (1/4-1/16)	64%	16%	27%
Week 54 (2/1-2/13)	58%	18%	25%
Week 55 (3/1-3/13)	58%	21%	22%
Week 58 (6/7-6/19)	63%	19%	29%
Week 59 (6/28-7/10	55%	14%	25%
Week 60 (7/26-8/7)	73%	19%	27%
Week 61 (8/23-9/4)	62%	25%	30%

The data that is presented in Table 11 is further expanded by the information set forth in Exhibit RDC-2. Exhibit RDC-2 begins with the methods used in last seven days to meet spending needs and distributes those methods by the extent to which, if at all, households using particular "methods" have difficulty in paying their home energy bills.

The data shows that, for Pennsylvania, households there is a relationship between people who rely on their savings accounts (or who sell assets or possessions) and those who have difficulty in paying their home energy bills. Over all eight survey periods, only roughly 60% of households who said they used a savings account (or who sold assets or possessions to meet their spending needs) also said they "never" were unable to pay their utility bill (or to pay their utility bill in full). People who turned to borrowing from friends or family to meet their spending needs had even greater difficulties. Consistently

over all survey periods, only one-in-four households borrowing from friends or family said they "never" were unable to pay their utility bill or to pay their utility bill in full.

Q. IS THERE ANY OTHER ASPECT OF THIS USE OF RESOURCES TO MEET HOUSEHOLD SPENDING NEEDS WHICH YOU HAVE EXAMINED?

A. There is substantial research which finds that having liquid assets of as little as $1,999 plays a significant role in preventing households from experiencing "material hardships." One study by the Urban Institute, for example, reported quite explicitly that

> Based on multivariate analysis of the lowest income quintile, holding liquid assets in modest amounts (up to $1,999, compared with having no such assets) is significantly related to a lowered incidence of material hardship for six of the eight hardship outcomes studied. This suggests that liquid asset holdings provide a buffer stock of financial resources, enabling households to respond to circumstances that would otherwise bring hardship.[26]

Missed utility payments, as well as utility shutoffs, were two of those six hardship outcomes affected. In addition to this Urban Institute study, the U.S. Federal Reserve addresses the impacts arising from the ability of households to have modest savings each year in its annual Report on the Economic Well-Being of U.S. Households. According to the Federal Reserve, "Having a buffer of savings for emergencies can help families cope with fluctuations in income and with unexpected expenses. The share of adults who would pay for an unexpected $400 expense with cash or the equivalent was unchanged from 2023, while the share who said they had rainy day funds to cover three months of

[26] Mills and Amick (2010). Can Savings Help Overcome Income Instability, Perspective on Low-Income Working Families, Brief No. 18, at page 8 (internal notes omitted).

expenses edged up from 2023."[27] In its most recent annual report, the Federal Reserve stated:

> Relatively small, unexpected expenses, such as a car repair or a modest medical bill, can be a hardship for many families, especially those without a financial cushion. When faced with a hypothetical expense of $400, 63 percent of all adults said they would have covered it exclusively using cash, savings, or a credit card paid off at the next statement (referred to, altogether, as "cash or its equivalent"). The remainder said they would have paid by borrowing or selling something or said they would not have been able to cover the expense.
>
> * * *
>
> Eighteen percent of adults said the largest emergency expense they could handle right now using only savings was under $100, and 13 percent said they could handle an expense of $100 to $499.[28]

The Federal Reserve found that only 24% of households with income less than $25,000 had sufficient savings to cover three months of household expenses, substantially less than households with higher incomes.[29] These 2025 findings are nearly identical to prior years.[30]

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[27] Federal Reserve System, Research and Analysis (May 2025). Economic Well-Being of U.S. Households in 2024, at 41.

[28] Id., at 42 (emphasis added).

[29] Id., at 44.

[30] See, e.g., Federal Reserve System, Research and Analysis (May 2024). Economic Well-Being of U.S. Households in 2023, at 31-32; Federal Reserve System, Research and Analysis (May 2023). Economic Well-Being of U.S. Households in 2022, at 31; Federal Reserve System, Research and Analysis (May 2020). Economic Well-Being of U.S. Households in 2019, at 21; Federal Reserve System, Research and Analysis (May 2020). Economic Well-Being of U.S. Households in 2019, at 21; Federal Reserve System, Research and Analysis (May 2019). Economic Well-Being of U.S. Households in 2018, at 21.

It is not the case that lower-income households simply have inadequate savings. Instead, it is reasonable to expect that these households have *no* savings. According to the U.S. Consumer Financial Protection Bureau (CFPB), "the level of emergency savings generally increases with the level of household income. This is not surprising as lower income households are generally more financially constrained and likely find it harder to save. Among consumers with annual household incomes of $20,000 or less, over half (60 percent) have *no* emergency savings, with the share falling to 40 percent for those with incomes between $20,001 to $50,000."[31] In 2020, based on pre-COVID data collection through the CFPB's "Making Ends Meet" survey, the CFPB reported that nearly three-quarters of households with income less than $20,000 have less than $100 in their checking or savings accounts.[32]

Q. DOES THIS NATIONAL DATA REFLECT CIRCUMSTANCES IN PENNSYLVANIA AS WELL?

A. Yes. Pennsylvania data is consistent with the detailed national data I present above. According to United for Alice, discussed above, while the emergency savings rate for *all* households in Pennsylvania reached 60% in 2022, "only 46% of households below the ALICE Threshold had emergency savings (or rainy day funds) that would cover their expenses for three months in the event of sickness, job loss, economic downturn, or

[31] CFPB Office of Research (March 2022). Emergency Savings and Financial Security, Insights from the Making Ends Meet Survey and Consumer Credit Panel, at 11,et seq. (emphasis added); see also, CFPB (December 2023). Making Ends Meet in 2023, Insights from the Making Ends Meet Survey.

[32] CFPB Office of Research (September 2020). Perceived Financial Preparedness, Saving Habits, and Financial Security, at 4.

another emergency. . .”[33] The National Financial Capability Study (2024) found that 45% of Pennsylvania households do not have emergency funds.[34] One contributing cause to this, according to the NFCS, was that 24% of households were spending more than their income, while an additional 34% were spending about equal to their income.

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and analysis above, I conclude that an exclusive focus of affordability discussions on the incomes of households is too narrow of an analysis. In addition to considering the income levels of households, to better understand the affordability of UGI bills, it is also necessary to consider the available resources. The data clearly shows that both from year-to-year, and from month-to-month, UGI bills will vary sharply. Not only do low-income households lack sufficient income to pay higher-than-expected annual bills out of regular income, they also lack sufficient resources to absorb spikes in cold weather heating bills. This observation affects multiple aspects of how UGI Gas interacts with its customers. It is, of course, one reason why the failure of UGI Gas to identify its low-income customers, or to enroll those customers which have been identified into CAP, is a failure to provide reasonably adequate service. In addition, aside from CAP, UGI Gas should engage in a more aggressive marketing of budget billing, particularly to customers (low-income and not) who experience payment difficulties. Finally, it is one reason why

[33] United for ALICE (2024 Update). An Update on Financial Hardship in Pennsylvania, at page 11; see also, The State of ALICE in Pennsylvania: 2025 Report, at page 9 (“in 2023, respondents below the ALICE Threshold in the Middle Atlantic Census Division (which includes Pennsylvania) were far less likely to than those above the Threshold to have savings that could cover three months of expenses in the event of an emergency (41% vs. 74%). . .”)

[34] FINRA Investor Education Foundation (2024). National Financial Capability Study (2024), Summary of Selected Findings: Pennsylvania.

the ongoing reliance by UGI Gas on traditional credit and collection techniques, such as sending shutoff notices, entering into payment arrangements, requiring high downpayments for payment arrangements, or failing to refund deposits to low-income customers (or to exempt such customers from the payment of deposits with which to begin), are both inefficient and ineffective. I will address these implications in greater detail below.

Part 2. The Effectiveness and Efficiency of UGI Gas Credit and Collection Expenditures.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review the efficiency and effectiveness of the credit and collection activities which UGI Gas directs towards its residential customers, including low-income customers. Given the failure of UGI Gas to reasonably identify its low-income customers, viewing the problems which UGI Gas faces exclusively from the perspective of Confirmed Low-Income customers would be too narrow. The activities directed toward residential customers as a whole, and the expenditures on those activities, must be incorporated into the discussion.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR DISCUSSION BELOW.

A. I base my discussion below on Section 523 of Pennsylvania's Public Utility Code. Section 523 provides:

> The commission shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates under this title. On the basis of the commission's consideration of such evidence, it shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate.

Based on this statutory language, I find that it is appropriate to review the "efficiency, effectiveness, and adequacy" of the credit and collection activities of UGI Gas and to recommend adjustments to "specific components of the utility's claimed cost of service" to the extent that such activities are found to be ineffective and/or inefficient.

Q. WHAT EXPENDITURES WILL YOU CONSIDER?

A. I base my review of expenditures primarily on the credit and collection expenditures for both residential and Confirmed Low-Income residential customers, as reported annually to BCS and published by BCS in its annual report on Universal Service Programs and Collections Performance.[35] The credit and collection expenditures of UGI Gas, as reported in the most recent BCS report, are set forth in Table 12 below.

Table 12. UGI Gas Credit and Collection Expenses (residential and Confirmed Low-Income [CLI])

	2024		2023		2022	
	Residential	Confirmed Low-Income	Residential	Confirmed Low-Income	Residential	Confirmed Low-Income
Total $s of C&C expenditures	$8,115,946	$2,759,422	$9,366,647	$2,634,185	$6,455,365	$1,860,969
CLI as percent of total	34.0%		24.0%		16.1%	

How these dollar figures were included in the Company's cost-of-service study (COSS) was subsequently provided by UGI Gas in response to discovery.[36] Using the Company's responses, and its COSS, the proposed adjustments I recommend below are reflected in the Direct Testimony of OCA witness Jennifer Rogers.

[35] The BCS annual reports are available at https://www.puc.pa.gov/filing-resources/reports/universal-service-programs-and-collections-performance-reports/

[36] OCA-15-4 – OCA-15-7.

Q. PLEASE PROVIDE THE BACKGROUND FOR YOUR REVIEW OF THE EFFECTIVENESS OF UGI GAS COLLECTION ACTIVITIES.

A. Table 13 presents background data demonstrating the lack of effectiveness of collection activities directed toward the Company's Confirmed Low-Income customers. The data shows, for example, that in 2024, while Confirmed Low-Income customers represented 9.0% of the total residential revenue, Confirmed Low-Income customers represented 71.8% of the total residential dollars in debt. Similarly, while Confirmed Low-Income customers represented only 14.1% of all residential customers, they represented 44.3% of residential accounts in arrears. As I will discuss further below, the fact that the Confirmed Low-Income dollars in debt is a higher percentage of the total than the percentage of Confirmed Low-Income accounts in debt indicates that low-income customers in debt are facing higher than average bills.

Table 13. Collection Outcomes for Confirmed Low-Income (CLI) Accounts

	2024	2023	2022
Percent CLI Revenue of Tot Res Revenue	9.0%	10.1%	5.9%
Pct CLI $s in debt of Total Res Revenue. In Debt	71.8%	71.0%	70.4%
Pct CLI customers of total customers	14.1%	14.4%	13.7%
Pct CLI accts in debt of total res. accts in debt	44.3%	43.2%	47.5%

Q. HAVE YOU HAD THE OPPORTUNITY TO FURTHER REVIEW THE EFFECTIVENESS OF UGI GAS COLLECTIONS DIRECTED TOWARD RESIDENTIAL AND CONFIRMED LOW-INCOME RESIDENTIAL CUSTOMERS?

A. Yes. Table 14 below presents the collection outcomes for residential and Confirmed Low-Income customers of UGI Gas for the three years most recently reported by BCS. The data demonstrates that UGI Gas does a poor job of responding to the unaffordability problems faced by low-income customers, instead allowing those customers to fall into

debt, having service disconnected for nonpayment, failing to reconnect service to customers having once disconnected their service, and ending up writing off a far higher percentage of revenue. The data shows that:

- A far higher percentage of UGI Gas' Confirmed Low-Income customers are in arrears than residential customers as a whole. In 2024, for example, three times more Confirmed Low-Income customers (29.6%) than residential customers (9.4%) were in debt. While the underlying absolute numbers varied somewhat by year, the ratio of Confirmed Low-Income to Residential customers in debt remained consistent from year to year over the past three years.

- An even higher percentage of Confirmed Low-Income dollars are in debt. The implication of this is that the Confirmed Low-Income accounts which are in debt have higher bills than Confirmed Low-Income accounts in general. If the average bill of customers in debt was equal to the average bill generally, the percentage of customers in debt and percentage of revenue in debt would be identical. The fact that the percentage of revenue in debt is higher means that each account in debt has a higher than average bill.

- The average arrears for a Confirmed Low-Income customer is more than 60% higher than the average arrears of a residential customer generally. In 2024, the most recent year, the average Confirmed Low-Income arrears of $798.34 was 62% higher than the average residential debt generally. Whatever collection activity UGI Gas is directing toward Confirmed Low-Income customers is evidently not working.

- One impact of the higher percentage of customers (and revenue) in debt, along with higher arrearage balances, is that UGI Gas resorts to nonpayment service disconnections more frequently for Confirmed Low-Income customers. BCS notes that "Termination of public utility service is the most serious consequence of customer non-payment and *is viewed as a last resort* when customers fail to meet their payment obligations."[37] Given the failure to collect, in other words, UGI Gas is forced into a use of the "last resort" from one quarter (2023) to one-third (2022, 2024) more frequently for Confirmed Low-Income customers.

[37] 2024 BCS annual Report, supra, at 11 (emphasis added).

- One problem with the over-reliance on service disconnections when other collection activities have failed is that UGI Gas frequently does not reconnect service after it has disconnected service. More than one-quarter of disconnections are not followed-up by a reconnection of service. Given the disproportionate number of disconnections with which to begin, this means that a disproportionate number of Confirmed Low-Income customers are losing their service and not being reconnected.

- Finally, one impact of this disproportionate share of disconnections, with one-of-four disconnected customers never being reconnected, is that the gross write-off of Confirmed Low-Income revenues is much higher than it is for residential customers as a whole. The gross write-off of Confirmed Low-Income revenue is from 65% to 165% higher than it is for residential revenue. Most recently, the gross write-off of confirmed Low-Income revenue was 81% higher than it was for residential customers.

Table 14. UGI Gas Credit and Collection Outcomes
(Confirmed Low-Income [CLI] versus Total Residential)

	2024		2023		2022	
	Residential	Confirmed LI	Residential	Confirmed LI	Residential	Confirmed LI
Percent customers in debt	9.4%	29.6%	10.6%	32.0%	10.2%	30.5%
Pct revenue in debt	4.8%	38.4%	5.1%	35.6%	4.7%	56.2%
Average arrears balance	$492.15	$798.34	$538.37	$884.22	$523.84	$896.65
DNP percent	4.8%	6.4%	5.0%	6.2%	4.3%	5.7%
Pct RNPs of DNPs	75.5%	74.3%	73.5%	74.7%	74.1%	71.8%
Gross write-off pct	6.7%	12.1%	5.1%	8.4%	3.9%	10.3%

In each of the instances discussed above, given that the Confirmed Low-Income customer data is a subset of the total residential data, the difference between the non-low-income "residential" numbers and the "Confirmed Low-Income" numbers would be even higher than is presented.

Q. HAVE YOU HAD AN OPPORTUNITY TO CONSIDER THE EFFICIENCY OF UGI GAS COLLECTION ACTIVITIES?

A. Yes. Table 15 below presents data on the efficiency of UGI Gas collection activities. The Table examines payment arrangements in particular. I consider payment arrangements because, as BCS notes, "debt that is on a payment arrangement is considered active and is often easier to collect than debt not on a payment arrangement."[38] Citing payment arrangements in particular, BCS asserts that one "purpose of the Chapter 56 regulations is to 'provide functional alternatives to termination.'"[39] UGI Gas is neither effectively nor efficiently serving that purpose.

Table 15. UGI Gas Deferred Payment Arrangement (DPA) Outcomes
(Confirmed Low-Income [CLI] vs. Total Residential)

	2024	2023	2022
# of UGI Gas CLI accts in arrears	26,338	28,770	25,946
Industry total # CLI accounts in arrears	76,701	78,779	67,958
UGI Gas as percent of industry total	34%	37%	38%
# of UGI Gas CLI Deferred Payment Arrangements	14,498	17,221	19,913
Industry total # of DPAs	92,950	98,133	69,437
UGI Gas as percent of industry total	16%	18%	29%
CLI # UGI Gas Payment Troubled accounts	18,002	19,270	17,139
Industry total # of Payment Troubled accts	73,066	73,008	58,929
UGI Gas as percent of industry total	25%	26%	29%

The data shows that while UGI Gas had 34% of Confirmed Low-Income accounts in arrears in 2024, it had only 16% of the confirmed low-income deferred payment arrangements. This difference was not unique to 2024. UGI Gas lagged in its percentage of Confirmed Low-Income accounts on payment arrangements in 2023 and 2022 as well.

[38] 2024 BCS Annual Report, at 15.

[39] Id. (internal notes omitted).

Moreover, the data shows that even when UGI Gas enters into a payment arrangement with Confirmed Low-Income customers, it has a disproportionate number of the payment-troubled customers amongst Pennsylvania natural gas utilities. According to BCS, PUC regulations define "payment-troubled" as "a customer who has failed to maintain one or more payment arrangements in a 1-year period."[40] The BCS data shows that while UGI Gas had 16% of all Confirmed Low-Income payment arrangements amongst Pennsylvania natural gas utilities in 2024, it had 25% of all payment-troubled Confirmed Low-Income customers. Not only is UGI Gas enrolling a disproportionately small percentage of Confirmed Low-Income customers in payment arrangements, of those who it does enroll, there are a disproportionately high percentage which have defaulted on at least one arrangement in the past twelve months. Standing on its own, but particularly when viewed in conjunction with the payment outcomes of Confirmed Low-Income customers discussed above, the ineffectiveness and inefficiency of the collection efforts directed by UGI Gas toward Confirmed Low-Income customers is evident.

Q. DOES UGI GAS HAVE ALTERNATIVES TO THE COLLECTION EFFORTS WHICH IT CURRENTLY DIRECTS TOWARD ITS CONFIRMED LOW-INCOME CUSTOMERS?

A. Yes. UGI Gas seems to ignore the findings of the PUC made more than 30 years ago when the Commission first began to explore the use of CAPs by the state's utilities. According to an early Commission order regarding CAPs (sometimes referred to by a different acronym):

[40] BCS 2024 annual Report, at 10, citing 52 Pa. Code §§ 54.72, 62.2

> We, in conjunction with utilities, and social service agencies, have all worked hard to devise ways to [e]nsure that low-income Pennsylvanians have utility services which really are necessities of life as the tragic fire deaths associated with the loss of utility service underlined. .
>
> However, for the poorest households with income considerably below the poverty line, existing initiatives do not enable these customers to pay their bills in full and to keep their service. . .Consequently, to address realistically these customers' problems and to stop repeating a wasteful cycle of consecutive, unrealistic payment agreements that cannot be kept, despite the best of intentions, followed by service termination, then restoration, and then more unrealistic agreements, we believe that new approaches like PECO's CAP program and the OCA's proposed EAP program should be tried.[41]

The Commission shortly thereafter prescribed the "model" CAP, stating that such programs are "designed to be a more cost-effective approach for dealing with issues of customer inability to pay than are traditional collection methods.[42] Despite these Commission findings, here we are with UGI Gas still continuing to primarily rely on "unrealistic agreements" rather than aggressively identifying its low-income customers and enrolling those customers into CAP.

Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT IDENTIFYING LOW-INCOME CUSTOMERS AND ENROLLING THOSE CUSTOMERS INTO CAP WOULD RESULT IN EFFECTIVE AND EFFICIENT COLLECTIONS?

A. UGI Gas' data demonstrates that enrollment in CAP will enhance the collection of revenue from low-income customers. Table 16 below shows the CAP payment

[41]Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, R-891468, Final Order, at 159 (September 19, 1990).

[42] Policy Statement on Customer Assistance Programs (CAP), Docket No. M-00920345, at 2 (July 2, 1992).

outcomes reported by UGI Gas for the years 2022 through 2024. The UGI Gas data shows that in contrast to the 29.6% of Confirmed Low-Income accounts in arrears, and 38.4% of Confirmed Low-Income revenue in arrears, in 2024, UGI Gas CAP customers paid 84.3% of their bills in-full, and 56% of their CAP bills not only in-full, but on-time. In 2024, of the CAP bills paid, 85% of the payments were made by the CAP customers, not including energy assistance payments such as LIHEAP.

Table 16. Payment Outcomes of UGI Gas CAP Participation[43]

	2024	2023	2022
Pct paid by CAP customers	85.0%	75.7%	93.3%
Pct CAP bill paid in full	84.3%	79.7%	92.0%
Pct CAP bill paid on-time	55.8%	79.7%	61.3%

This BCS data is also consistent with the most recent independent evaluation of the UGI Gas CAP.[44] The UGI Gas Evaluation found that enrollment in CAP resulted in a 17% improvement in the number of accounts who missed zero (0) payments.[45] Moreover, the Evaluation found that the percentage of UGI Gas CAP customers who paid 100% or more of their bill increased from 33% (pre-CAP) to 66% (in-CAP), compared to an actual decrease in the percentage of low-income comparison group customers paying 100% or more of their bill.[46] In contrast, the percentage of CAP participants who paid less than

[43] BCS 2024 annual Report, at 66.

[44] APPRISE, Inc. (April 2024). UGI Universal Service Programs, Final Evaluation Report.

[45] Id., at page 75.

[46] Id., at page 74.

80% of their bills declined from 51% (pre-CAP) to 19% (in-CAP), compared to a decline in the low-income comparison group of 10% (pre-CAP) to 9% (in-CAP).[47]

Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT UGI GAS DOES AN INEFFECTIVE JOB OF IDENTIFYING ITS LOW-INCOME CUSTOMERS AND ENROLLING THOSE CUSTOMERS IN CAP?

A. I discuss the identification of low-income customers, and the enrollment of low-income customers in the Company's CAP, in detail in the next section.

Q. WHAT DO YOU RECOMMEND?

A. As I discuss above, Section 523 of the Public Utility Code provides that the Commission "shall" (i.e., mandatory language) consider the "efficiency, effectiveness and adequacy" of service. The statute further provides that the Commission "shall" (again using mandatory language) "give effect to this section by making such adjustments to specific components of the utility's claimed cost of service." The credit and collection expenses reported by BCS are just such a "component of the (UGI Gas) claimed cost of service." Based on the findings I make and support above regarding the inefficiency and ineffectiveness of the UGI Gas expenditures, making such an adjustment is appropriate. Given the need for such an adjustment, I recommend a fifty-fifty sharing of the credit and collection expenses which UGI Gas proposes to include in its cost of service. This adjustment is dollarized and explained in more detail in the direct testimony of OCA witness Jennifer Rogers.

[47] Id., at pages 74 - 75.

Part 3. Enhancing UGI Gas Identification of its Low-Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain the failure of UGI Gas to reasonably and adequately identify its Confirmed Low-Income customer base and to enroll those customers in its CAP. I make specific recommendations on how that identification and enrollment can and should be improved.

Q. PLEASE EXPLAIN THE EXTENT TO WHICH UGI GAS IDENTIFIES ITS LOW-INCOME CUSTOMERS AND ENROLLS THOSE CUSTOMERS INTO ITS CAP.

A. UGI Gas has identified fewer than 60% of its estimated low-income population as "Confirmed Low-Income" according to data which it reports to BCS. According to the BCS data, in 2024, UGI Gas identified only 58% of its estimated low-income population as "Confirmed Low-Income," an increase from 54% in 2023, but still missing more than two-of-five low-income customers.[48]

UGI does a poor job of then enrolling its Confirmed Low-Income customers into CAP. UGI Gas data documents that consistently more than 40,000 Confirmed Low-Income customers are *not* enrolled in CAP.

[48] BCS 2024 annual Report, at page 6.

Table 17. Confirmed Low-Income Customers Not Enrolled in CAP by Month[49]				
Month	2023	2024	2025	2026
January	35,614	37,218	41,424	42,561
February	36,640	38,457	43,371	
March	35,767	38,447	41,956	
April	37,115	38,434	42,602	
May	36,148	38,386	42,444	
June	36,182	38,844	42,556	
July	36,128	38,290	42,165	
August	35,528	38,204	41,827	
September	35,966	38,988	42,103	
October	35,680	39,121	41,606	
November	36,533	41,163	42,501	
December	37,440	41,108	42,897	

UGI Gas also does a poor job of enrolling its Confirmed Low-Income customers into the federal energy assistance program (LIHEAP). While the most recent count of Confirmed Low-Income customers was 66,139,[50] in the 2024-2025 LIHEAP program year, only 24,682 received any type of LIHEAP assistance.

Table 18. Number of CLI Customers Received Grant by Grant Type (2024/2025)	
Cash Only	7,036
Crisis Only	1,907
Both Cash & Crisis	1,668
Supplemental	14,071

Of those, 3,575 low-income customers received LIHEAP Crisis assistance. Generally, Crisis assistance is provided to prevent a disconnection of service for nonpayment. This Crisis participation can be compared to the 12,495 Confirmed Low-Income customers for whom UGI Gas disconnected service for nonpayment in 2025 (a Crisis participation of

[49] CAUSE-PA-1-9(b).

[50] CAUSE-PA-1-8(b).

only 28%). More than seven-of-ten disconnected customers that UGI Gas had a reasonable belief to be low-income were not enrolled in LIHEAP Crisis, the federal program designed to prevent such disconnections. As can be seen in the Company's data, low-income customers can receive both Cash and Crisis grants, but do not.

Q. IS THERE A COMPARABLE PROGRAM TO WHICH YOU CAN COMPARE THE ENROLLMENT OF UGI GAS CUSTOMER LIHEAP ENROLLMENT?

A. Yes. The UGI Gas LIHEAP enrollment of 24,682, for example, can be compared to the SNAP participation rate in Pennsylvania in 2022 (the last year for which data is available), which exceeded 98% of SNAP-eligible low-income households in Pennsylvania.[51] While not suggesting that UGI Gas could achieve a 98% LIHEAP enrollment rate, the comparison shows how far short the performance of UGI Gas is in identifying and enrolling its low-income customers in beneficial energy assistance programs such as LIHEAP and CAP.

Q. DO YOU HAVE A SPECIFIC RECOMMENDATION THAT UGI GAS SHOULD ADOPT?

A. Yes. There are easily accessible means for a customer to provide a reasonable basis for UGI Gas to conclude that a customer is "low-income" without the customer enrolling in CAP or receiving a LIHEAP grant. Consider, for example, that a customer could establish that they are receiving means-tested public assistance by providing either a printout or a

[51] See, https://fns-prod.azureedge.us/sites/default/files/resource-files/ear-snap-Reaching-Those-in-Need-2022.pdf

screenshot through the State of Pennsylvania's COMPASS app.[52] In the alternative, customers could provide a printout of their welfare verification from the county assistance office.. Not only is verifying actual income more challenging for a variety of reasons (such as uncooperative employers when wages are paid under the table, or inconsistent pay statements), but customers may also have legitimate concerns about sharing information regarding the children in their household. Providing actual income, as well as specific information about children, to UGI Gas is certainly not required to create a reasonable expectation by the Company of a customer's low-income status. My first recommendation, therefore, is that UGI Gas, at a minimum, accept either a printout or a screenshot of the COMPASS application as adequate documentation to establish Confirmed Low-Income status.

My second recommendation relates to CAP enrollment, not merely to establishing Confirmed Low-Income status. My recommendation is that Confirmed Low-Income customers who are negotiating a deferred payment agreement (DPA) with the Company, as well as customers from whom the Company receives information placing them in an income tier of 0% to 150% FPL, should be provided a stand-alone written Plain Language notice informing those customers of their right, in the alternative, to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions). Through that opportunity, rather than needing to agree to retire their arrears over an extended period of time, the Confirmed Low-Income customer would be allowed to enroll in CAP (if income-qualified) and, upon making appropriate

[52] COMPASS is an online tool for Pennsylvanians to apply for many health and human service programs and manage benefit information. See, compass.dhs.pa.gov/home/#/

payments, receive a forgiveness of their underlying arrearages. This written communication would be provided to Confirmed Low-Income customers, those customers from whom UGI had previously received sufficient information to reasonably establish their low-income status. A Confirmed Low-Income customer should be enrolled in a deferred payment arrangement only with their informed consent that they would prefer to retire their arrears in installments paid in addition to their undiscounted monthly bill rather than enrolling in CAP and receiving both a substantial discount and the forgiveness of their arrears.

There is a statutory basis for this requirement. Pennsylvania statutes provide that:

> No public utility shall, directly or indirectly, by any device whatsoever, or in anywise, demand or receive from any person, corporation, or municipal corporation a greater or less rate for any service rendered or to be rendered by such public utility than that specified in the tariffs of such public utility applicable thereto. The rates specified in such tariffs shall be the lawful rates of such public utility until changed, as provided in this part. *Any public utility, having more than one rate applicable to service rendered to a patron, shall, after notice of service conditions, compute bills under the rate most advantageous to the patron*.[53]

(emphasis added). UGI Gas should not, in other words, require a customer, known to be a Confirmed Low-Income customer, to pay off arrears through a payment arrangement which arrears would be subject to forgiveness under the Company's CAP. The Recommended Decision in the 2025 Columbia Gas rate proceeding agreed, stating that "Both CAUSE-PA and OCA propose that the Commission should require Columbia to implement routine screening of its applicants and customers to determine eligibility for

[53] 66 Pa. Stat. and Cons. Stat. Ann. § 1303 (West)(emphasis added).

CAP and other universal service programs. . .We agree with both CAUSE-PA and OCA on this issue. Improved screening and referrals could help ensure households are receiving the most advantageous available rate and is a statutory requirement."[54]

Q. HAS THIS OR ANY SIMILAR ISSUE OF THIS "INFORMED CONSENT" BEEN RECENTLY ADDRESSED BY THE COMMISSION?

A. Yes. In the April 4, 2024 decision regarding the Universal Service and Energy Conservation Plan (USECP) of Columbia Gas, the PUC considered whether Columbia could apply an existing deposit against a low-income customer's outstanding arrears before refunding the difference pursuant to statute and regulation. The PUC held that the Company could *not* do so, stating:

> Commission regulations also state that a public utility must "refund a deposit, along with any applicable interest, within 60 days upon determining that the customer or applicant from whom a deposit was collected is not subject to a deposit…." *See* 52 Pa. Code § 56.53(f). The regulations do not permit the public utility to apply a deposit to a delinquent account balance if it is determined the customer was not responsible for paying the deposit prior to accruing the balance.
>
> Accordingly, we direct Columbia to refund security deposits, with applicable interest, collected from customers who are income–eligible for CAP. Columbia may apply the security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill.[55]

[54] Pennsylvania PUC v. Columbia Gas of Pennsylvania, Docket R-2025-3053499, Recommended Decision, at page 549 (October 3, 2025).

[55] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024 - 2028 Submitted in Compliance with 52 Pa. Code § 62.4, Docket M-2023-3039487, Order, at 31 (April, 2024). (hereafter 2024 Columbia USECP Order).

While that decision related to Columbia, the application of the legal principles would be the same. In a similar fashion, UGI Gas should be allowed to require a Confirmed Low-Income customer to pay off arrears through a payment arrangement "only with the customer's informed consent." Moreover, as the PUC stated with respect to applying deposits against arrearage balances, "as part of obtaining this informed consent," the Company must explain to the customer how enrolling in CAP and making the customer's arrearage subject to arrearage forgiveness "would impact the customer's monthly bill." The customer should know, prior to entering into a payment arrangement, that under a payment arrangement, the customer would pay a monthly installment over and above their regular monthly bill in contrast to bills under CAP, which would provide substantial discounts along with arrearage forgiveness.

Q. HAVE YOU REVIEWED THE RESULTS OF THE UGI GAS LOW-INCOME CUSTOMER ASSESSMENT AND OUTREACH PILOT IN REACHING YOUR CONCLUSIONS AND FORMULATING RECOMMENDATIONS?

A. Yes, to the extent available. In the July 2025 Settlement of its 2025 base rate case, UGI Gas agreed to "continue its Low-Income Customer Assessment and Outreach Pilot established by Paragraph 46 of the Commission-approved settlement at Docket No. R-2021-3030218. . ."[56] In turn, in the 2021 Settlement, UGI Gas had agreed to engage a third party consultant, selected through a competitive bid process, to engage in a low-income identification and outreach program. When asked for "details on the current

[56] Joint Petition for Settlement, Docket No. R-2024-3052716, at para. 61 (July 9, 2025).

status" of that outreach pilot, and any "interim or final findings, conclusions, or lessons learned as a result of this pilot," UGI Gas responded:

> UGI Gas launched the Low Income Customer Assessment and Outreach Pilot on March 3, 2026. The Company utilized email and direct mail campaigns, which included 2 postcards mailed to approximately 45,000 customers and 3 emails sent to approximately 67,000 customers. Additionally, the Company initiated paid search and social media advertising. As of April 2, 2026, 385 customers have enrolled in CAP as a result of this pilot.[57]

UGI did not explain how it determined that the 385 new CAP enrollees were "as a result of this pilot." Over the past three years, UGI Gas experienced a enrollment of 1,198 new CAP participants (2023), 1,089 new CAP participants (2024), and 1,084 new CAP participants (2025).[58] If the 385 is an incremental (or additional) enrollment over the enrollment levels that would ordinarily occur in March in any event (as evidence by the last three years), that is a substantial improvement.

Nor did UGI Gas explain how it selected the 45,000 customers to receive postcards and the 67,000 customers to receive emails. Nonetheless, given the fact that the launch of this Pilot occurred fewer than six weeks prior to the time this testimony is being written, there has been insufficient time to assess the effectiveness or efficiency of the Pilot. Based on this discussion, I recommend that UGI Gas be directed to provide its Low-Income Advisory Committee regular three month reports on the operation and effectiveness of its Low-Income Customer Assessment and Outreach Pilot.

Part 4. Low-Income Deposit Exemptions.

[57] CAUSE-PA-8-1.

[58] CAUSE-PA-2-1(B).

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the extent to which UGI Gas appropriately complies with statutory and regulatory requirements to exempt low-income customers from being required to post and/or maintain cash security deposits. I find that UGI Gas is in substantial non-compliance with the PUC's low-income deposit exemption requirements.

Q. WHAT DOES THE PUC'S REGULATION PROVIDE?

A. The PUC's regulations require that:

> . . .a public utility may not require a cash deposit from an applicant who is, based upon household income, confirmed to be eligible for a customer assistance program. An applicant is confirmed to be eligible for a customer assistance program by the public utility if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirement that are consistent with those of the public utility's Customer Assistance Program.[59]

In addition, aside from being applicable to "applicants," the Commission has further extended this prohibition to existing customers as well.[60]

Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT UGI GAS DOES NOT COMPLY WITH THIS REQUIREMENT?

A. UGI Gas does not comply with this prohibition on requiring deposits from low-income customers. When asked to describe "all instances where UGI informs low income

[59] 52 Pa. Code § 56.32(e).

[60] 52 Pa. Code § 56.41(B)(4).

customers about the availability of the exemption from security deposit collection and ability to receive a refund of their security deposit," UGI Gas responded:

> UGI Gas informs low-income customers about the availability of the security deposit exemption and the ability to receive a refund of their security deposit through several touchpoints. When a customer is identified as verified low-income through enrollment in a qualifying program, the customer's account is automatically updated and any held security deposit is released at that time. Customers are notified of this action via their account statement reflecting the deposit return.[61]

The UGI response continued on to state that "For self-reported low income customers, customers are advised that they will be sent a CAP application/waiver letter."[62] That CAP application/waiver letter, however, states that "To have this deposit waived, you must have your income verified by completing the enclosed assistance application form. . . You do not have to enroll in CAP for the security deposit and any reconnection fees to be waived, but your stated income must still be verified through this process. . . If you choose not to have your income verified through this process, you must pay the security deposit shown on your bill and any reconnection fees, if you were shut off for nonpayment."[63]

UGI Gas states that it does not track the number of deposits held from Confirmed Low-Income customers, the number Confirmed Low-Income customers from whom the Company is holding a cash security deposit, the dollars of cash security deposits the

[61] CAUSE-PA-6-1.

[62] Id.

[63] CAUSE-PA-6-1 and CAUSE-PA-6-9 (Attachment 1).

Company is holding from Confirmed Low-Income customers, or the dollars of deposits that have been returned to Confirmed Low-Income customers.[64]

UGI Gas will not return a deposit to a customer unless and until that customer has applied for CAP and had their income confirmed to make them income-eligible for CAP.[65] The Company does not routinely or periodically review the accounts from whom it has collected a cash security deposit to determine whether the account is eligible for a deposit exemption.[66]

Q. PLEASE EXPLAIN HOW UGI GAS RETURNS DEPOSITS?

A. UGI Gas will not return a deposit to a customer unless and until that customer has applied for CAP and had their income confirmed to make them income-eligible for CAP.[67] The Company does not routinely or periodically review the accounts from whom it has collected a cash security deposit to determine whether the account is eligible for a deposit exemption.[68]

Q. DOES THE PUC REGULATION REQUIRE A CUSTOMER TO PROVIDE ACTUAL INCOME TO QUALIFY FOR A DEPOSIT EXEMPTION?

A. No. Indeed, the PUC's regulation explicitly states to the contrary. According to the PUC regulation, a customer or applicant is exempt from deposits "if the applicant provides

[64] CAUSE-PA-6-3.

[65] CAUSE-PA-6-5.

[66] CAUSE-PA-6-6.

[67] CAUSE-PA-6-5.

[68] CAUSE-PA-6-6.

income documents *or other information* attesting to his or her eligibility for state benefits based on household income eligibility requirement that are consistent with those of the public utility's Customer Assistance Program." UGI's procedures completely ignore the language in the regulation that I have highlighted ("or other information"). Moreover, by requiring customers or applicants to be found income-eligible for CAP as a prerequisite to being exempt from a deposit, UGI Gas completely writes out of the PUC's regulation the exemption of customers who have provided information "attesting to" their eligibility for "state benefits."

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UGI Gas be directed to modify its processes and procedures regarding the low-income exemption from deposits. UGI Gas should be directed to accept *any* information beyond information on income and household size that would "attest to" the household's eligibility for a state benefit that is consistent with CAP income requirements. Use of COMPASS information, such as I describe above to establish Confirmed Low-Income status, is one example of such information. I further recommend that UGI Gas be directed to eliminate the requirement that a customer must apply for CAP in order to establish their eligibility for a deposit exemption. I finally recommend that within three months of a final order in this proceeding, and every three months thereafter, UGI Gas undertake a review of the cash security deposits it currently holds and report the results of such review to interested stakeholders in this proceeding. To the extent that cash security deposits are held for Confirmed Low-Income customers, those deposits should be refunded in accordance with PUC precedent.

Q. DO YOU HAVE ANY FINAL CONCERNS ABOUT THE UGI GAS PROCESSES FOR DEPOSIT EXEMPTIONS AND REFUNDS?

A. Yes. The UGI Gas description of its deposit refunds, as quoted above, states that when customers are found to be eligible for a deposit exemption, "customers are notified of this action via their account statement reflecting the deposit return." This language seems to indicate that deposits are only returned as a credit on the customer's account. That process violates numerous PUC decisions holding that such a process is inappropriate.

The Commission has explicitly held the procedure outlined in the UGI Gas description to be unlawful. In the April 4, 2024 decision regarding the Universal Service and Energy Conservation Plan (USECP) of Columbia Gas, the PUC considered whether Columbia Gas could apply an existing deposit against a low-income customer's outstanding arrears before refunding the difference pursuant to statute and regulation. The PUC held that the Company could *not* do so, stating:

> Commission regulations also state that a public utility must "refund a deposit, along with any applicable interest, within 60 days upon determining that the customer or applicant from whom a deposit was collected is not subject to a deposit…." *See* 52 Pa. Code § 56.53(f). The regulations do not permit the public utility to apply a deposit to a delinquent account balance if it is determined the customer was not responsible for paying the deposit prior to accruing the balance.
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> Accordingly, we direct Columbia to refund security deposits, with applicable interest, collected from customers who are income–eligible for CAP. Columbia may apply the security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill.[69]

[69] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024 - 2028 Submitted in Compliance with 52 Pa. Code § 62.4, Docket M-2023-3039487, Order, at 31 (April, 2024). (hereafter 2024

While that decision related to Columbia Gas, the application of the legal principles would be the same for UGI Gas.

Part 5. Reducing the Collection and Retention of Social Security Numbers by UGI Gas.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review the practice of UGI Gas in collecting and retaining customer Social Security Numbers (SSNs). I recommend that UGI Gas be directed to develop and adopt, within 12-months after a final order in this proceeding, an alternative to the use of SSNs.

Q. PLEASE DESCRIBE THE UGI GAS PRACTICES REGARDING THE COLLECTION AND RETENTION OF SOCIAL SECURITY NUMBERS.

A. According to UGI Gas:

> The Company collects and stores tax IDs — Social Security Numbers (SSNs) for individuals and Employer Identification Numbers (EINs) for organizations — to verify the identity and creditworthiness of service applicants. However, a driver's license number is accepted in lieu of a tax ID.
>
> * * *
>
> The tax ID further serves as a unique, persistent link between a customer and their account history. For this reason, it is retained on the customer record even after service is discontinued, preventing billing errors, duplicate accounts, and confusion arising from common names.[70]

Columbia USECP Order). See also, Philadelphia Gas Works Universal Service and Energy Conservation Plan for 2023-2027 Submitted in Compliance with 52 Pa. Code § 62.4, Docket M-2021-3029323, Order on Reconsideration, at 17 – 18 (also appropriate to refund deposits directly to customer without seeking customer consent on whether to refund or to credit deposit toward bill).

[70] OCA-10-1. The complete response to OCA-10-1 is provided in Exhibit RDC-3.

Q. HOW DO YOU RESPOND TO THE COMPANY'S COLLECTION AND PERMANENT RETENTION OF SOCIAL SECURITY NUMBERS?

A. In response to the growing use of Social Security Numbers (SSNs) in enabling the crime of identity theft, the PUC should join the growing consensus that institutions such as UGI Gas that have collected SSNs in the past refrain from, or be prohibited from, collecting such SSNs in the future, and that UGI Gas be directed to seek out alternatives to the collection and use of SSNs.[71]

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT UGI GAS SHOULD BE DIRECTED TO REFRAIN FROM THE COLLECTION AND RETENTION OF SOCIAL SECURITY NUMBERS AND TO DEVELOP AN ALTERNATIVE TO THE COLLECTION AND RETENTION OF SUCH PERSONAL DATA.

A. The use of SSNs by private entities is one of the leading causes of identity theft. SSNs, along with a person's date of birth and name, are the three most sought-after pieces of personal information sought by identity thieves. According to the 2007 report of the Presidential Task Force on Identity Theft, a person's SSN is the ***single*** most important piece of personally identifiable information available to identity thieves. Unlike names and

[71] According to the FTC: "Concerns about over-use of SSNs and their role in identity theft have increased in recent years. In a recent consumer survey, 66 percent of the respondents stated that companies should stop using SSNs to identify customers and 64 percent perceived that they were more vulnerable to identity theft when a business had their SSN." FTC (November 2007). "Staff Summary of Comments and Information Received Regarding the Private Sector's Use of Social Security Numbers," at 2.

addresses, which can change over a person's lifetime, it is "virtually impossible" for a person to change his/her SSN.[72]

SSNs are viewed as a "breeder document" by identity thieves, a fact that UGI conceded it is aware of.[73] With a Social Security Number, an identity thief can create other false documents supporting a false identity, including a driver's license, retail credit account, credit card account, bank account, and similar papers. Indeed, given the lack of a standard protocol for truncating SSNs, even truncated SSNs are not helpful in preventing identity theft. While some businesses truncate the first five digits of an SSN, other businesses truncate the last four. Not only can SSNs thus be reformulated with information from multiple sources, but those multiple sources need also not be illicitly gained. Public documents such as tax liens, driving histories, voter registrations, bankruptcies, and the like, are all publicly available information which might be used to match all or part of an SSN obtained from a utility record with a specific individual.

Q. IS THERE GENERAL GUIDANCE TO REDUCE THE USE OF SOCIAL SECURITY NUMBERS?

[72] Unlike a lost key, the social security number cannot be changed merely because it has been lost or stolen. "Identity Theft and Your Social Security Number," Social Security Administration, Pub. No. 05-10064, Oct. 2007, at 6, available at http://www.ssa.gov/pubs/10064.pdf. There must be evidence that (1) someone is in fact wrongfully using the number, and (2) that the individual to whom the number belongs is being disadvantaged by the wrongful use.

[73] OCA-10-24.

A. Yes. There has been clear direction in recent years to reduce, and eliminate where possible, the unnecessary collection of SSNs. In 2007, the federal Office of Management and Budget (OMB) issued a memo requiring federal agencies to examine their use of SSNs in systems and programs in order to identify and eliminate instances in which collection of SSNs is unnecessary. OMB required agencies to explore alternatives to their use of SSNs. Like OMB's guidance to federal agencies, the Federal Trade Commission (FTC) has urged a reduction in the use of SSNs in the private sector. FTC testified to Congress that there was a need to eliminate the unnecessary use of SSNs. The FTC cited the observation of the Presidential Task Force on Identity Theft that it is not clear whether the use of SSNs by the private sector was a necessity, or a result of "convenience and habit."[74] The President's Task Force stated quite simply in 2007 that "more must be done to eliminate unnecessary use of SSNs." UGI concedes that it is aware of the guidance of OMB,[75] the Federal Trade Commission,[76] and the President's Task Force on Identity Theft.[77]

Consider, also, the advice of Peter Swire. Swire was the Chief Counselor for Privacy in the Office of Management and Budget for President Bill Clinton's Administration,. "Social Security Numbers," Swire says, "are an aging technology, and we have to do

[74] President's Identity Theft Task Force (2007). Combating Identity Theft: A Strategic Plan, at 24

[75] OCA-10-25.

[76] OCA-10-26.

[77] OCA-10-27.

serious planning for what will come next."[78] Swire's comment was responding to a study published in the proceedings of the National Academy of Science by, Acquisti and Gross, researchers at Carnegie Mellon University. The Acquisti and Gross study was able to identify, through a computer statistical analysis, the first five digits of a person's SSN for 44% of persons borne after 1988, and for 7% of those born from 1973 to 1988.[79] The accuracy of the prediction system increased for smaller states and for people born after 1988. While the researchers were able to predict all nine digits of an SSN for 8.5% of those born after 1988 in fewer than 1,000 attempts (testing the data on a half million persons), they needed 10 or fewer tries to predict all nine digits for 1 out of 20 Social Security numbers assigned in Delaware.[80]"Unless mitigating strategies are implemented," the Acquisti and Gross study itself found, "the predictability of SSNs exposes them to risks of identity theft on mass scales."[81]

The concerns raised by Acquisti and Gross were somewhat mitigated when, in 2011, the Social Security Administration began to randomly assign SSNs. Prior to that change in June 2011, however: (1) the first three digits of the SSN were called the "area number" and represented the state where a person lived when the SSN was issued; (2) the next two digits were the "group number" and grouped Social Security numbers within a state into

[78] New York Times, "Weakness in Social Security Numbers is Found," July 6, 2009.

[79] Knowing the first five digits of an SSN easily leads to the discovery of the entire SSN. Due to different truncation protocols, while some entities truncate the first four digits of an SSN, other entities truncate the last four digits, thus allowing partial SSNs to be easily matched.

[80] Acquisti and Gross (2009). "Predicting Social Security Numbers from Public Data," Proc. Natl Acad. Sci. USA 106:10975-10980.

[81] Predicting Social Security Numbers, supra.

blocks of numbers; and (3) the final four numbers were the "serial number" and identified each individual within a block. The Acquisti and Gross research, in other words, still presents cause for concern. Even today, in 2026, persons who received random-generated numbers have still not even reached the age of majority. Despite this Carnegie Mellon study, and the frequently recognized role of the use of Social Security Numbers in enabling identity theft, UGI Gas has undertaken no effort to examine the use of Social Security Numbers in enabling identity theft.[82]

Q. HOW DO YOU RESPOND TO THE UGI GAS ASSERTION THAT IT HAS A NECESSITY TO USE SOCIAL SECURITY NUMBERS TO PREVENT FRAUD?

A. UGI Gas asserts, but provides no supporting data or analysis, that it needs to use SSNs in order to prevent fraud, by identifying the identity and creditworthiness of service applicants.[83] Moreover, UGI Gas consistently argues that "The Company disagrees that its practice of collecting SSNs for the limited purpose of credit verification in connection with establishing utility service is improper and/or not in compliance with applicable legal and regulatory requirements."[84]

Despite this UGI Gas assertion, it has frequently been found that Social Security Numbers are not good "authenticators." It is not merely consumer advocates that have expressed concern. As early as 1995, the newsletter of the Association for Computing Machinery (ACM), reported on the "risks of Social Security Numbers":

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[82] OCA-10-22.

[83] OCA-10-1, attached as Exhibit RDC-3.

[84] See, e.g., OCA-10-23 through OCA-10-27.

> The problem with social security numbers is that some organizations are using these ubiquitous numbers for identification, others are using them for authentication, and still others are using them for both. I call up my bank, tell them my account number and ask them for a balance. Just to make sure that I am really who I claim to be, my bank asks for my SSN—as if this is a number that is some kind of secret that we share.
>
> But my SSN isn't secret—and there is no way to make it that way in today's increasingly cross-indexed society. That's because for every organization that thinks your SSN should be kept secret, there's another that is using it as some kind of account number, leaving it open for all of the world to see.[85]

There are three ways for a person to authenticate who they are: (1) by something they *know* (like a PIN or password); (2) by something they *have* (like a physical device or token); or (3) by something they *are* (like a physical characteristic such as a fingerprint, or an age and birthdate). Authenticators should not be widely known, perhaps even should be secret. The problem is that SSNs are *widely* known,[86] and even if not known, can be accurately predicted by computer statistical analysis as shown by the Carnegie Mellon research discussed immediately above. The historic use of SSNs as an authenticator by UGI Gas is not a sufficient reason for the Commission to approve the continued collection and use of SSNs.

Q. DOES UGI GAS LACK INFORMATION ABOUT RECOMMENDED BEST PRACTICES WITH RESPECT TO THE COLLECTION AND RETENTION OF SOCIAL SECURITY NUMBERS?

[85] Garfinkel (October 1995). "Risks of Social Security Numbers," Vol. 38, No. 10, Communications of the ACM.

[86] See e.g., Given (December 2007). "Uses of Social Security Numbers in the Private Sector: Why SSNs are not Appropriate for Authentication," Privacy Rights Clearinghouse presentation to the Federal Trade Commission Workshop "Security in Numbers: SSNs and ID Theft."

A. Yes. When asked whether the Company was "aware that the Federal Trade Commission ("FTC") has urged, in guidance or public statements, a reduction in the use of Social Security Numbers in the private sector," UGI Gas responded that it "is unable to admit or deny that the FTC has 'urged,' in guidance or public statements, a reduction in the use of Social Security Numbers (SSNs) in the private sector because the Company is unaware of any currently applicable guidance issued by the FTC on this topic." Despite this blindness to FTC guidance, the FTC has, in its publication "A Guide for Business: Protecting Personal Information," in fact ***explicitly*** recommended with respect to private sector collection and retention of Social Security Numbers: "***Don't use*** Social Security Numbers unnecessarily— for example, as an employee or ***customer identification number***, or because you've always done it."[87]

Despite this FTC guidance –"don't use Social Security Numbers. . .as [a]. . .customer identification number," that is precisely what UGI Gas ***does*** do. The Company explicitly states that "UGI has not considered any plans to move away from the use of Social Security Numbers."[88] This failure to act in light of the FTC's recommendation occurs even though UGI has undertaken no studies that examine the effectiveness of the use of Social Security Numbers as an identifier or other indicator of an individual's identity.[89]

[87] U.S. Federal Trade Commission, "Guide for Business: Protecting Personal Information," at page 6 (emphasis added), available at https://www.ftc.gov/system/files/documents/plain-language/pdf-0136_proteting-personal-information.pdf

[88] OCA-10-18.

[89] OCA-10-20.

UGI Gas collects SSNs from 99.3% of its customers.[90] The Company collects SSNs for the express purpose of providing them to a third party ("The Company asks for a new customer's SSN when they apply for service *so an Experian check can be run* to verify their identity.")[91] Experian's use of, and protection of, SSNs is not subject to the jurisdiction of the Pennsylvania PUC. Indeed, UGI Gas has no control over how Experian protects Social Security Numbers.

In addition, not only does the Company collect these SSNs, but it also retains them in perpetuity ("The tax ID further serves as a unique, persistent link between a customer and their account history. For this reason, it is retained on the customer record *even after service is discontinued*, preventing billing errors, duplicate accounts, and confusion arising from common names.")[92] The Company's assertion, in other words, that it collects SSNs "for the limited purpose of credit verification in connection with establishing utility service" is not an accurate statement.

Q. DOES UGI GAS INFORM OR NOTIFY CUSTOMERS AT THE TIME SOCIAL SECURITY NUMBERS ARE REQUESTED OF THEIR INTENDED RETENTION AND USE?

[90] OCA-10-3.

[91] OCA-5-6. (emphasis added).

[92] OCA-10-1 (emphasis added).

A. No. When customers are asked to provide their SSNs at the time they apply for UGI Gas service, they are neither informed, nor notified, of the Company's intended retention and expansive use of the personal data. UGI Gas:[93]

- Does not inform or notify customers that their SSN will be retained in perpetuity, including after the time the household is no longer a customer of the Company;
- Does not inform or notify customers that their SSN will be provided to a third party (Experian), an international credit agency operating in North America, Central America, South America, Europe, the Middle East, Asia, and Australia. According to Experian, itself, its business purpose involves "transforming complex data into actionable insights. From credit risk assessment to fraud prevention and market analysis. . ."[94]
- Does not inform customers of the fact that Experian will also appear to be authorized to retain customer Social Security Numbers. If Experian is not so authorized, there would be nothing for UGI Gas to match a customer SSN to in an "Experian Connect Check" in order to "verify the applicant's identity." UGI Gas states: "to establish service, a Customer Care Representative (CCR) will run an Experian Connect Check to verify the applicant's identity. If the Connect Check

[93] OCA-10-2 ("When an applicant calls to request service, a Social Security Number (SSN) is requested for identity and creditworthiness verification. Applicants who prefer not to provide an SSN are verbally informed that a driver's license number is an acceptable alternative."). See also, OCA-10-9 ("The Company accepts a Driver's License number as an alternate form of identification, to verify identity and creditworthiness of a service applicant. If an applicant declines to provide either Social Security Number or Driver's License number, they are informed that they must supply one government-issued photo ID or two alternative forms of identification, at least one of which must include a photo.").

[94] Available at https://www.experianplc.com/about-us/experian-at-a-glance

returns a result that indicates an identity issue, the CCR will deny service until valid identification is provided."[95]

Q. DO YOU HAVE REASON TO BELIEVE THAT CUSTOMER DATA WILL BE SHARED WITHIN THE UGI CORPORATE STRUCTURE BEYOND UGI GAS?

A. Yes. In response to discovery, UGI Gas stated that:

> UGI maintains a comprehensive, defense-in-depth program for safeguarding Customer Personal Information, including Social Security Numbers, from unauthorized access, disclosure, or use. This program is governed by a suite of *enterprise information security standards and procedures applicable across all business units, including UGI Utilities*.[96]

UGI's response goes on to state:

> UGI's Global Information Security Group (GISG) maintains an enterprise information security program anchored to the NIST Cybersecurity Framework (CSF). Formal policies governing the acceptable use of information systems, data classification, access control, incident response, and third-party risk management *apply to all employees, contractors, and temporary workers across all UGI business units and geographic locations*.[97]

Note several things that are important in this response. The security program is not operated and maintained by UGI Gas but rather is an "enterprise information security program" maintained by "UGI's Global Information Security Group (GISG)." The "security standards and procedures" are not specific to UGI Gas, but rather are "enterprise. . .standards and procedures applicable *across all business units*. . ." The reference to "all business units" is not limited to UGI Gas, and only "*include[es]* UGI

[95] OCA-10-5.

[96] OCA-10-6 (emphasis added). A complete copy of the response to OCA-10-6 is appended to my Direct Testimony as Attachment RDC-4.

[97] Id. (emphasis added).

Utilities." Remember, UGI Utilities includes not only its gas operations, but its electric operations as well in Pennsylvania; it also operates in Maryland. UGI Utilities also has, as a wholly owned subsidiary, Mountaineer Gas Company, which is the largest gas utility in West Virginia. UGI owns AmeriGas Propane, the largest retail propane gas marketer in the United States, operating in all 50 states.

Q. WHAT DO YOU CONCLUDE?

A. SSNs are an "aging technology" and private sector entities relying on SSNs, such as UGI Gas, need to engage in serious planning on what will come next. Research, including but not limited to[98] that research published in the proceedings of the National Academy of Science discussed below, concludes that industry and policy makers need to "reassess our perilous reliance" on SSNs. The federal government has told all federal Executive Agencies to "eliminate the unnecessary collection and use" of SSNs. The Presidential Task Force on Identity Theft concluded that "more must be done to eliminate the unnecessary use of SSNs." No reason exists for UGI Gas to lag behind in eliminating or minimizing the collection and retention of SSNs. There is a distinct move to find

[98] See, U.S. House of Representatives, Hearing Before the Committee on Oversight and Government Reform (My 23, 2017). Protecting American's Identities: Examining Efforts to Limit the Use of Social Security Numbers, available at https://oversight.house.gov/hearing/protecting-americans-identities-examining-efforts-limit-use-social-security-numbers/

See also, Mack (March 3, 2020). The Move to Eliminate Social Security Numbers ("At the 2020 RSA Cybersecurity Conference last week, the head of the Cybersecurity and Infrastructure Security Agency (CISA) reiterated that the country needs to move away from SSNs for identification. The past few years have seen numerous high-profile data breaches and we've reached a point where up to an estimated 80% of Americans' SSNs have already been exposed.") available at https://www.extractsystems.com/the-move-to-eliminate-social-security-numbers/

alternatives to the use of SSNs to help reduce the threat of identity theft.[99] The Commission should direct UGI Gas join in those efforts. UGI should be directed to report to the Commission, within 12 months of a final decision in this docket, its plan to eliminate the collection and retention of customer Social Security Numbers. This plan should include a plan for elimination of the SSNs currently retained in Company information technology.

Part 6. Reviewing the 2025 UGI Gas Rate Case Settlement Commitments.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review the commitments which UGI Gas agreed to as part of the Settlement of its 2025 base rate case proceeding. In that Settlement, UGI Gas agreed in relevant part:

- To implement the Commission's Common Application Form for enrollment in CAP, increased flexibility for confirmed low income customers to enroll in

[99] See, e.g., U.S. Department of Homeland Security (January 18, 2019). Social Security Number Collection and Use Reduction. "With this Instruction, the Department of Homeland Security (DHS) Chief Privacy Officer: (A) Requires the elimination of the unnecessary collection, use, maintenance, and dissemination of the Social Security number (SSN) by DHS programs, systems, and forms; or (B) Requires the use of a unique alternative identifier to the SSN; or (C) Requires the use of privacy-enhancing SSN alternatives when there are technological, legal, or regulatory limitations to eliminating the SSN."

See also, Government Executive (April 12, 2024). "The Office of Personnel Management issued a final rule Friday that would cull Social Security numbers from any mailed document in an effort to prevent fraud. The rule, which was published in the Federal Register, is part of the implementation of the 2017 Social Security Number Fraud Prevention Act and is designed to help protect the identifiers, which can be used in various forms of identity theft. . .The federal government has been working on reducing the use of SSNs as identifiers since at least 2006, when the Identity Theft Task Force, created by a George W. Bush executive order, called for the Office of Management and Budget and OPM to find ways to eliminate, restrict or conceal SSN use." available at https://www.govexec.com/management/2024/04/opm-rule-removes-social-security-numbers-mailed-documents/395700/#:~:text=The%20Office%20of%20Personnel%20Management,an%20effort%20to%20prevent%20fraud

varying programs by and through data sharing, and quarterly working group meetings dedicated to increasing enrollment to CAP.[100]

- To automatically recertify CAP customers who consent to sharing income by checking the LIHEAP data sharing box on the LIHEAP application;[101]
- To no longer require applicants for CAP, LIURP, or Operation Share programs to produce income documentation if the applicant received LIHEAP within the current or prior LIHEAP season and are included within the LIHEAP data shared by DHS;[102]
- Through 2026, to host quarterly working group meetings with interested parties and members of its Advisory Committee to identify considerations for utilizing LIHEAP data to facilitate auto-enrollment in CAP;[103]
- To increase its LIURP budget by $1,000,000 annually, effective January 1, 2026;[104]
- To roll-over any unspent LIURP funds at the end of the calendar years and add that amount of money to the budget for the following year;[105]
- To continue its Low-Income Customer Assessment and Outreach Pilot for a term of three years beginning April 1, 2026;[106]
- To increase its outreach efforts through additional in-person Winter Assistance Relief Mobilization (WARM) events held at targeted locations each calendar year;[107]

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[100] See, Joint Petition for Settlement, Docket Nos. R-2024-3052716, et al., at paragraphs 59(a) (July 9, 2025).

[101] Id., at para. 59(b).

[102] Id., at para. 59(c).

[103] Id., at para. 59(d).

[104] Id., at para. 60(a).

[105] Id., at para. 60(c).

[106] Id., at para. 61.

[107] Id., at para. 61(b).

- To "engage with local officials" and provide its USP brochure in English and Spanish to the Mayor's offices in selected cities;[108]

- To commence tracking beginning in 2026 and continuing for a period of three years, "annual progress" for resulting reductions related to: (1) low-income nonpayment disconnections; (2) payment-troubled customers (as defined by the PUC); (3) the number of Confirmed Low-Income customers who are living in occupied housing units without heating at the time of the PUC's Cold Weather Survey, and, in the absence of reductions in any of the above metrics, to develop a plan to generate such reductions;[109]

- To increase its annual shareholder donation to Operation Share by $500,000;[110] and

- To waive reconnection fees for any Confirmed Low-Income customers who provide verification of household income and to develop a "clear process" for households to verify their income in order to waive the reconnection fee.[111]

Q. HAS UGI GAS COMPLIED WITH EACH ASPECT OF THE SETTLEMENT THAT YOU JUST LISTED?

A. In general, there has been insufficient time since approval of the 2025 Settlement to determine the extent to which UGI Gas is complying with the Settlement terms. UGI Gas has proposed a $1,000,000 LIURP budget in accord with the Settlement,[112] and is using LIHEAP data to recertify CAP customers.[113] As of December 2025, UGI Gas has adopted

[108] Id., at para. 61(c).

[109] Id., at para. 61(d).

[110] Id., at para. 62(a).

[111] Id., at para. 64.

[112] UGI Gas Statement 12, at page 8.

[113] CAUSE-PA-6-16.

the PUC's Common Application Form for purposes of CAP enrollment.[114] It has acknowledged its commitment to increase its Operation Share funding by $500,000.[115] The dollar amount of Operation Share grants in November 2025 through January 2026 ($862,136) was substantially higher than the dollar amount in the equivalent time periods for 2024-2025 ($162,575) or 2023-2024 ($267,370).[116] While total spending in 2025-2026 was up, the average per-household Operation Share grant amount in those months declined.[117]

It is, however, simply too early to assess the Company's compliance with the outreach and public engage aspects of the 2025 Settlement. For example, UGI committed to increasing Low-Income Customer Assessment and Outreach through a continued pilot program for the next three years, which include but are not limited to Winter Assistance Relief Mobilization (WARM) events and increased engagement with local officials to provide its USP brochure in English and Spanish at local city halls. The Company is proposing no changes to any of its Universal Service programs in this proceeding.[118] What is evident, however, is the number of new CAP enrollees was somewhat higher in October 2025 through January 2026 (3,917) than it had been in the same months in 2024-

[114] UGI Gas Statement 12, at page 15.

[115] Id., at page 8.

[116] CAUSE-PA-2-17(B). Part of this, however, may be attributable, at least in part, to a one-time supplemental grant made by UGI (gas and electric) to Operation Share in response to delays in LIHEAP funding in the Fall of 2025 caused by the government shutdown at that time.

[117] CAUSE-PA-2-17(A).

[118] CAUSE-PA-1-2.

2025 (3,663) or 2023-2024 (3,237).[119] The total number of net additions to CAP enrollment (the "net" is new program enrollment minus program exits)[120] in the period October 2025 through January 2026 (884) did not differ sharply from prior years. The number of customers removed from CAP due to a "failure to recertify" was somewhat lower in the period October 2025 through January 2026 (1,414) than the same months in 2024-2025 (1,516), but modestly higher than in the same months in 2023-2024 (1,1118). There has, in other words, simply been too little time since the Settlement of the 2025 UGI Gas rate case to assess the extent to which UGI Gas is meaningfully pursuing the types of outreach and engagement that were included in the 2025 Settlement or the impacts on CAP enrollment from the 2025 Settlement agreements regarding recertification processes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[119] CAUSE-PA-2-1(B).

[120] The total CAP enrollment is set forth in response to CAUSE-PA-1-6; the number of new CAP enrollees is set forth in response to CAP-2-1. The number of CAP exists, including the number of exists due to a "failure to recertify" is set forth in response to CAUSE-1-13.

Exhibit RDC-1: Summary Vitae

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA

* * * * * * * * * * * * * * * * * * * *

Education:

J.D. (Phi Kappa Phi, Order of the Coif) University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

Professional Experience:

Licensed to practice law in Iowa (1981 to present)

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 – present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than forty (40) states. He is particularly noted for creative program design and implementation within tight budget constraints.

Professional Affiliations:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar

Coordinator: BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator: Belmont Affordable Shelter Fund (BASF)
Past Chair: Belmont Solar Initiative Oversight Committee
Past Member: City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair: Belmont Energy Committee
Member: Massachusetts Municipal Energy Group (Mass Municipal Association)
Past Chair: Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Chair: Board of Directors, Belmont Housing Trust, Inc.
Past Chair: Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member: Belmont (MA) Energy and Facilities Work Group
Past Member: Belmont (MA) Uplands Advisory Committee
Past Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Chair: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: Board of Directors, Affordable Comfort, Inc.
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

Professional Associations:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)

Association for Social Economics

Books

Colton, *et al.,* ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

Book Chapters

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

Journal Publications

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

Technical Reports

200 technical reports for public-sector and private-sector clients (list available upon request)

Jurisdictions in which Expert Witness Provided

1. Maine	17. Tennessee	33. Montana
2. New Hampshire	18. Kentucky	34. Colorado
3. Vermont	19. Ohio	35. New Mexico
4. Massachusetts	20. Indiana	36. Arizona
5. Rhode Island	21. Michigan	37. Utah
6. Connecticut	22. Wisconsin	38. Idaho
7. New Jersey	23. Illinois	39. Nevada
8. Maryland	24. Minnesota	40. Washington
9. Pennsylvania	25. Iowa	41. Oregon
10. Washington D.C.	26. Missouri	42. California
11. Virginia	27. Kansas	43. Hawaii
12. North Carolina	28. Louisiana	**Canadian Provinces**
13. South Carolina	29. Arkansas	1. Nova Scotia
14. Florida	30. Texas (Federal Court)	2. Ontario
15. Alabama	31. South Dakota	3. Manitoba
16. Mississippi	32. North Dakota	4. British Columbia

Exhibit RDC-2:

Exhibit RDC-2: Pennsylvania: Ability to Pay an Energy Bill by Method Used in Last Seven Days to Meet Spending Needs				
	Household was unable to pay an energy bill or unable to pay the full bill amount			
Method used in the last 7 days to meet spending needs*	Almost every month	Some months	1 or two months	Never
Week 61 (8/23 - 9/4)				
Regular income sources	3.1%	7.8%	6.8%	69.8%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	5.8%	14.3%	10.2%	61.2%
Borrowing from friends or family	18.2%	24.8%	17.7%	23.5%
Week 60 (7/26 - 8/7)				
Regular income sources	4.0%	7.5%	5.6%	69.6%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	3.2%	10.2%	8.4%	63.2%
Borrowing from friends or family	14.2%	28.7%	6.0%	31.8%
Week 59 (6/28 - 7/10)				
Regular income sources	5.9%	8.0%	7.3%	68.3%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	7.6%	12.2%	13.3%	58.4%
Borrowing from friends or family	15.4%	26.4%	18.7%	27.7%
Week 58 (6/7 - 6/19)				
Regular income sources	4.0%	7.7%	6.9%	71.3%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	5.8%	13.5%	7.1%	66.1%
Borrowing from friends or family	16.7%	28.6%	15.8%	25.8%
Week 55 (3/1 - 3/13)				
Regular income sources	5.3%	7.3%	5.2%	71.4%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	6.1%	11.2%	6.4%	61.0%
Borrowing from friends or family	29.4%	27.9%	7.1%	20.5%
Week 54 (2/1 - 2/13)				
Regular income sources	5.1%	7.5%	6.3%	69.9%

Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	12.4%	9.8%	9.5%	58.5%
Borrowing from friends or family	27.3%	20.9%	6.6%	35.8%
Week 53 (1/4 - 1/16)				
Regular income sources	6.6%	5.8%	6.5%	67.0%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	7.7%	9.5%	10.8%	57.1%
Borrowing from friends or family	20.0%	21.8%	9.6%	32.6%
Week 52 (12/9 - 12/19)				
Regular income sources	4.8%	8.7%	7.4%	68.0%
Money from savings or selling assets or possessions (including withdrawals from retirement accounts)	5.7%	11.5%	9.8%	63.5%
Borrowing from friends or family	21.3%	34.0%	7.6%	22.6%

Exhibit RDC-3 (OCA-10-1)

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to OCA Set 10 (1-28)
Delivered on March 30, 2026

OCA-10-1

Request:

State whether the Company currently collects, stores, or otherwise maintains Social Security numbers or other Customer Personal Information that has been used historically or currently to establish, verify, or maintain utility service. If so, identify the categories of information collected, the purposes for which such information is collected, and the period of time such information is retained.

Response:

The Company collects and stores tax IDs — Social Security Numbers (SSNs) for individuals and Employer Identification Numbers (EINs) for organizations — to verify the identity and creditworthiness of service applicants. However, a driver's license number is accepted in lieu of a tax ID.

A tax ID is an established and reliable method to confirm an applicant's identity. This helps the Company detect fraud and protect other customers from bad actors seeking service under false identities to avoid outstanding balances. Because utility service is delivered before payment is received, credit verification also allows the Company to assess whether a deposit is warranted.

The tax ID further serves as a unique, persistent link between a customer and their account history. For this reason, it is retained on the customer record even after service is discontinued, preventing billing errors, duplicate accounts, and confusion arising from common names.

SSN was previously requested for enrollment for the Company's Universal Service Plans. However, pursuant to the Joint Petition for Settlement at Docket No. R-2024-3052716, Paragraph 59(a), the Company agreed to implement the PUC's Common Application Form and is utilizing it for its Customer Assistance Program and Operation Share as of December 2025. This form does not include a request for SSN. The Low Income Usage Reduction Program application does request, but not require the SSN, which is used for validation, if the Company finds that the same household members are listed in applications for separate properties. The Company is in the process of revising this application and the SSN will not appear on future versions.

Prepared by or under the supervision of: Daniel V. Adamo

Exhibit RDC-4 (page 1 of 3) (OCA-10-6)

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to OCA Set 10 (1-28)
Delivered on March 30, 2026

OCA-10-6

Request:

Describe in general terms the policies, practices, and procedures utilized by the Company to identify and address suspicious activity, fraudulent account creation, or unauthorized use of Customer Personal Information in connection with the establishment or maintenance of utility service. Without disclosing confidential or security-sensitive information, describe the overall approach to monitoring and detection (including whether such activities are conducted through automated processes, manual review, or a combination thereof), the general process for evaluating and escalating potential issues, and the manner in which the Company reviews, updates, and assesses the effectiveness of such policies and procedures over time.

Response:

UGI maintains a comprehensive, defense-in-depth program for safeguarding Customer Personal Information, including Social Security Numbers, from unauthorized access, disclosure, or use. This program is governed by a suite of enterprise information security standards and procedures applicable across all business units, including UGI Utilities. These controls address the prevention and detection of external cybersecurity threats, unauthorized intrusions, and internal misuse, and are subject to regular review, testing, and independent assessment.

I. Administrative Safeguards

Policies and Standards. UGI's Global Information Security Group (GISG) maintains an enterprise information security program anchored to the NIST Cybersecurity Framework (CSF). Formal policies governing the acceptable use of information systems, data classification, access control, incident response, and third-party risk management apply to all employees, contractors, and temporary workers across all UGI business units and geographic locations. All personnel with access to Customer Personal Information are subject to these policies as a condition of employment or engagement.

Training and Awareness. All UGI employees and contractors receive security awareness training covering the recognition and reporting of phishing, social engineering, and suspicious activity. Personnel with access to Customer Personal Information receive role-appropriate training on data handling requirements, acceptable use obligations, and reporting procedures. Ongoing awareness communications supplement formal training throughout the year.

Exhibit RDC-4 (page 2 of 3) (OCA-10-6)X

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to OCA Set 10 (1-28)
Delivered on March 30, 2026

OCA-10-6 (Continued)

Third-Party Risk Management. Vendors, suppliers, and business partners with access to UGI systems or Customer Personal Information are subject to security assessments prior to engagement and to contractual obligations governing data protection, acceptable use, and breach notification. Third-party breaches involving known or suspected impact to UGI customer data must be reported to the GISG immediately upon notification.

II. Technical Safeguards

Identity and Access Management. Access to systems and data containing Customer Personal Information is governed by the principle of least privilege. Access rights are assigned based on defined roles and business need and are subject to periodic review and recertification. Privileged access to critical systems and data repositories is subject to enhanced controls and oversight. Multi-factor authentication is enforced for remote access and access to sensitive systems. Terminated or transferred employees are subject to timely access revocation procedures.

Endpoint Protection. UGI deploys enterprise endpoint detection and response (EDR) technology to detect, contain, and remediate threats including malware, ransomware, and unauthorized execution. Endpoint security policies enforce configuration standards and restrict unauthorized software installation.

Data Protection. Customer Personal Information, including Social Security Numbers, is protected through encryption controls applied to data in transit across public and internal networks. Data handling and retention requirements are defined in UGI's information security standards and apply to all systems and personnel that store, process, or transmit customer data.

Security Monitoring — SIEM and SOC. UGI operates a security information and event management (SIEM) platform that aggregates and correlates log and alert data from across the enterprise technology environment. A managed security operations center (SOC) provides around-the-clock monitoring, alert triage, and escalation. Detection rules and threat indicators are continuously updated based on intelligence from sector-specific information sharing organizations and government partners.

Email and Collaboration Security. Anti-phishing and email filtering controls are deployed to detect and block malicious messages before they reach end users. Employees are provided with mechanisms to report suspicious emails, which are reviewed and actioned by the security team.

Exhibit RDC-4 (page 3 of 3) (OCA-10-6)

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to OCA Set 10 (1-28)
Delivered on March 30, 2026

OCA-10-6 (Continued)

Fraud-Specific Technical Controls. Please see the response to OCA-5-7.

Customer Operations Front-End Controls. Please see the response to OCA-5-7.

III. Physical Safeguards

Physical access to UGI facilities housing systems that store or process Customer Personal Information is controlled through layered physical security measures. Data center and server room environments are subject to access controls that restrict entry to authorized personnel. Physical security controls are incorporated into UGI's broader security planning and preparedness program. Physical security incidents with potential cyber implications — including unauthorized physical access to network infrastructure or computing equipment — are subject to the same incident escalation and response procedures as cybersecurity incidents.

Prepared by or under the supervision of: Hans G. Bell

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division
:

VERIFICATION

I, Roger Colton, hereby state that the facts above set forth in my Corrected Direct Testimony, OCA Statement No. 6 (Corrected), are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 3, 2026

Signature: /s/ *Roger Colton*
Roger Colton

Address: Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

Surrebuttal Testimony of Roger Colton

on behalf of

Pennsylvania Office of Consumer Advocate

OCA Statement 6SR

Date Served: May 27, 2026

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger D. Colton. My business address is 34 Warwick Road, Belmont, MA, 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED PRE-FILED WRITTEN DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes, I am.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of my Surrebuttal Testimony is to review and respond to the Rebuttal Testimony of the following UGI Gas witnesses to the extent that those witnesses address issues which I raise in my Direct Testimony:

- UGI Gas rebuttal witness Brian Meillinger;
- UGI Gas rebuttal witness Daniel Adamo;
- UGI Gas rebuttal witness John Taylor; and
- UGI Gas rebuttal witness Cyndee Fang.

Q. HAS THE REBUTTAL TESTIMONY OF UGI GAS WITNESSES CAUSED YOU TO MODIFY OR DROP ANY OF THE RECOMMENDATIONS BASED ON YOUR DIRECT TESTIMONY?

A. No. I stand by each of the recommendations I made based on the data and discussion presented in my Direct Testimony.

Part 1. Response to UGI Gas Rebuttal Witness Brian Meilinger.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of UGI Gas rebuttal witness Brian Meilinger.

Q. DO YOU HAVE ANY OVER-ARCHING OBSERVATIONS ABOUT THE REBUTTAL TESTIMONY OF BRIAN MEILINGER?

A. Yes. Mr. Meilinger concedes the unaffordability of UGI Gas rates to low- and moderate-income households. He explicitly states that he "does not dispute the income data" which I presented, or the Asset Limited, Income Constrained, Employed" figures which I cite in my testimony.[1] His dispute is limited to whether it is appropriate to consider this data in a rate proceeding to review the affordability of UGI Gas rates or to review the Company's Universal Service Programs.

As to Universal Service Programs, Mr., Meilinger asserts that the Company's programs "have been successfully assisting low-income customers, resulting in positive affordability outcomes for *many* participants."[2] Mr. Meilinger sets the bar far too low for what the obligations of UGI Gas are. The purpose of the Company's Universal Service Programs is not merely to generate positive affordability outcomes "for many participants." As the Commission's Bureau of Consumer Services (BCS) states:

> The Electricity Generation Customer Choice and Competition Act and the Natural Gas Choice and Competition Act opened the electric generation and

[1] UGI Gas Statement 12-R, at 2.

[2] Id. (emphasis added).

> natural gas supply markets to competition. In doing so, the General Assembly wanted to ensure that electric and natural gas service remain universally available to all customers in the state. Both Acts contain provisions that require utilities to make universal service and energy conservation programs available to assist low-income customers to afford electric and gas service. The Acts also require the PUC to ensure that utilities appropriately fund their assistance programs.[3]

The purpose of Universal Service Programs, in other words, is to "assist low-income customers to afford gas and electric service," not merely to generate "positive outcomes" for "many" participants.

While Mr. Meilinger states that UGI Gas is working to "ensure that payment troubled customers are provided with the necessary assistance to maintain utility service," he does not dispute the data showing that UGI Gas has three times more low-income customers in debt than residential customers; disconnects service for nonpayment at a rate 50% higher for low-income customers than for residential customers; writes-off low-income customer accounts at a rate two times higher than its writes off residential accounts; had more than 18,000 low-income customers default on payment arrangements in the most recent year for which data is reported; and has an average low-income arrearage balance nearly two times higher than the average residential balance. Mr. Meilinger does not dispute that UGI Gas has identified fewer than 60% of its low-income population and then, *of those*,

[3] Bureau of Consumer Services (January 2026). Universal Service Programs & Collections Performance, 2024, at page 2,, available at https://www.puc.pa.gov/filing-resources/reports/universal-service-programs-and-collections-performance-reports/ (internal notes omitted).

has more than 40,000 confirmed low-income customers that it has not enrolled in its Customer Assistance Program (CAP), its primary Universal Service Program.[4]

In short, generating "positive outcomes" for "many" participants does not achieve the statutory objective identified in the 2024 BCS Report.

Q. DO YOU HAVE A SECOND RESPONSE TO MR. MEILINGER'S REBUTTAL TESTIMONY?

A. Mr. Meilinger presents a red herring argument when he testified that the Commission "should not be holding a regulated utility, such as UGI Gas, solely accountable for participation rates in assistance programs that are administered by the Commonwealth of Pennsylvania."[5] Of course, no-one has proposed to hold UGI-Gas "solely accountable" for the low participation rate in LIHEAP. Nonetheless, when UGI Gas claims credit for LIHEAP participation,[6] and the financial benefits provided by the federal government which UGI Gas has claimed to have "facilitated" (in its own words),[7] it is legitimate to

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[4] Mr. Meilinger objects to using ALICE data to address the performance of the Company's Universal Service Programs. (UGI-Gas Statement 12-R, at page 6.) No-one, including myself, has done that, or proposed to do that. Indeed, the ALICE data was presented to support the proposition that affordability problems extend beyond the Company's low-income population. Accordingly, Mr. Meilinger's "objection" will not be further addressed.

[5] UGI Gas Statement 12-R, at page 21.

[6] UGI Statement 11-R, at page 30 ("considerations relating to the intersection of income and rate design would 3 be amiss if they did not include discussions relating to UGI Gas's low-income programs. 4 UGI Gas has available a continuum of low-income targeted programs, beyond CAP, 5 including facilitating Low-Income Home Energy Assistance Program ("LIHEAP"). . .") See also, UGI Gas Statement 12, at page 10 ("Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly $32 million.")

[777] Note that UGI Gas claims to have "facilitated" not merely *some* LIHEAP grants, but it claims credit for facilitating *all* of the LIHEAP grants received by the Company over the three-year period. ("Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly $32 million.") UGI Gas Statement 12-R, at page 11. The fact that Mr. Meilinger claims credit for

question whether the Company is also creating barriers to LIHEAP participation. In all of the ways I identified in my Direct Testimony, none of which Mr. Meilinger disputed, the Company does fail to do all it can, and does, indeed, create barriers.

Q. IS THERE A THIRD ASPECT OF MR. MEILINGER'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Yes. Mr. Meilinger seeks to divert attention from the Company's failures regarding its Universal Service Programs, identified both by myself and by CAUSE-PA witness Cicero, by citing government assistance programs regarding food, housing and housing, which address "the costs of basic needs. . .which are asserted by OCA and CAUSE-PA to put strain on household budgets."[8] Nothing in my Direct Testimony raises questions about how, if at all, UGI Gas should be involved with addressing the "costs of basic needs such as the food" outside of the context that there is documented data which I discuss about the extent to which households in Pennsylvania have reduced or forwent expenses for basic household necessities, such as medicine or food, *in order to pay an energy bill*. When utility bills become so unaffordable that customers make trade-offs with other household necessities in order to pay those bills, contrary to Mr. Meilinger's rebuttal testimony that it is of no concern to the utility, it falls squarely within Pennsylvania's statutory mandate for Universal Service Programs as I identified above.

"facilitating" *all* LIHEAP grants received by the Company is evident by comparing his claim at page 11 to the data presented by UGI Gas in response to OCA-IV-34(a) and 34(b). In fact, his claim that "the Company has facilitated approximately 109,000 grants" is suspect. According to the Company's data, only 72,659 LIHEAP Cash and Crisis grants were received by the Company *in total* in the three years Mr. Meilinger cites. (OCA-IV-34(a)).

[8] UGI Gas Statement 12-R< at page 5.

Q. WHAT IS THE FOURTH ASPECT OF MR. MEILINGER'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Mr. Meilinger presents extensive argument about how well UGI Gas is doing to provide "a concerted focus on continued marketing and customer outreach to increase CAP enrollment."[9] His testimony, however, misses the point. Quite aside from CAP enrollment, the Company has a responsibility to provide certain protections –identified in my Direct Testimony—to "confirmed low-income customers." The standard for being identified as a Confirmed Low-Income customer" is much lower than the standard for enrolling in CAP. While CAP enrollment requires a customer to apply for the program, and have their income-eligibility be verified, to be identified as a "Confirmed Low-Income customer" requires, by virtue of Commission regulation, *only* that UGI Gas have "a reasonable expectation reasonable expectation by the Company of a customer's low-income status."[10] Having a "reasonable expectation" that a customer is low-income is much different from establishing income-eligibility through an application and income verification process.

Mr. Meilinger argues that an OCA discovery response "suggests SNAP's guidelines differ from CAP's guidelines and are not based solely on gross income as a percentage of the Federal Poverty Level."[11] To assert that *that* was the OCA response to the cited discovery request is so misleading as to be willfully deceptive. The complete request, and the OCA

[9] UGI Statement 12-R, at 7 – 8.

[10] OCA Statement 6, at page 54.

[11] UGI Gas Statement 12-R, at 19 – 20.

response to that request, is attached to this Surrebuttal Testimony as OCA Exh. RDC-1SR. The part of the OCA response which Mr. Meilinger cites[12] stated in relevant part:

> SNAP income eligibility, of course, is not based exclusively on gross income as a percent of Poverty Level as asserted in the question. In addition, a household's net income must be less than 100% of Poverty Level. Households must meet both gross and net income limits to income-qualify for SNAP. The closer gross countable income comes to 200% of the Federal Poverty Level, the less likely it is that net income will fall below the additional income-qualifying guideline.

In addition, the OCA response which Mr. Meilinger so misleadingly cites, stated:

> The ***maximum*** income limits presented above, however, do not demonstrate whether or not demonstrating Food Stamp income participation is "consistent with" the income eligibility requirements for CAP. The Table below shows the distribution of Pennsylvania SNAP recipients by Federal Poverty Level in Pennsylvania for the three most recent years available (USDA, Characteristics of Supplemental Nutrition Assistance Program Households):

Distribution of SNAP participating households
by gross countable income as percent of poverty status: Pennsylvania

	Zero gross income	% to 50% FPL	% to 100% FPL	% or more FPL
2020	16.1%	10.2%	48.6%	25.0%
2021***			Not Published	
2022	17.4%	11.3%	39.9%	31.4%
2023###	16.9%	9.4%	37.7%	36.0%

***Due to a lack of data collection caused by the COVID health pandemic, no 2021 data was published.
###Most recent year available (published April 2025).

While USDA does not disaggregate SNAP recipient households into Poverty ranges of 100% to 150% and 150% or more, the disaggregation nonetheless documents that any reasonable distribution of SNAP recipients with income

[12] UGI Discovery to OCA, Set III, No. 1.

100% or more would demonstrate the consistency of Food Stamp eligibility with CAP eligibility.

Even the distribution presented above does not fully document the extent to which Food Stamp income eligibility is consistent with CAP income eligibility. The Table below shows the *average* Poverty Level of Food Stamp recipients in Pennsylvania by year for the years 2020 through 2023 (USDA, Characteristics of Supplemental Nutrition Assistance Program Households).

Gross Countable Income as Average Percent of Poverty Level of SNAP Recipient Households: Pennsylvania	
2020	74.8%
2021	***
2022	78.4%
2023###	85.9%

***Due to a lack of data collection caused by the COVID health pandemic, no 2021 data was published.
###Most recent year available (published April 2025).

As can be seen, rather than saying what Mr. Meilinger states the OCA response said, the response documents that a demonstration of SNAP participation would create a reasonable expectation that a UGI Gas customer is low-income. It may not be sufficient to certify income for purposes of CAP enrollment, but the PUC's regulations regarding Confirmed Low-Income status does not require that. Mr. Meilinger's need to so deceptively represent an OCA discovery response is, unto itself, evidence of the weakness of his argument.

Mr. Meilinger argues further that I over-state the significance of the fact that fewer than 40% of the Company customers which UGI Gas has reason to believe are low-income (24,682 of 66,139 = 37%) receive LIHEAP. He notes that some customers may receive LIHEAP but assign their benefits to their electric provider rather than to UGI Gas. In that situation, UGI Gas would not know that the customer had received LIHEAP. While

Pennsylvania does allow low-income households to assign LIHEAP to their secondary heating provider, it is not reasonable for Mr. Meilinger to assert that more than three-of-five LIHEAP recipients actually do so. His speculation as to what utility is the beneficiary of a household's LIHEAP grant is not a sound basis to conclude that engaging in two marketing initiatives a year to promote enrollment in CAP[13] is a sufficient alternative to the additional education and outreach directed to customers at a time they would most benefit from CAP enrollment.

Q. IS THERE A FIFTH ASPECT OF MR. MEILINGER'S TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Yes. While Mr. Meilinger concedes that he does "not dispute the ALICE data presented," he "disagree[s] that it is appropriate to use this data to analyze the impacts of the Company's rate case and/or its Universal Service Programs."[14] He argues that eligibility for the Company's universal service programs are based on Federal Poverty Level and that a rate case is not an appropriate forum to consider other alternatives.[15] In this regard, Mr. Meilinger's rebuttal testimony states that "Witness Colton's recommendation to analyze ALICE data would be better suited outside of a rate case proceeding, where various stakeholders, including the Commission and other community partners, would have the opportunity to provide input on his recommendations and consider the impacts of those recommendations. A base rate case, which involves a host of other issues and is

[13] UGI Gas Statement 12-R, at page 20.

[14] UGI Gas Statement 12-R, at page 6.

[15] Id.

on an expedited time frame for resolution, is simply not the appropriate time to consider such a recommendation."[16]

The problem with Mr. Meilinger's rebuttal is that I offered no proposal to use ALICE data as an alternative to the use of FPL to establish universal service program eligibility. Nor did I use the ALICE data to evaluate the UGI Gas universal service programs. I used ALICE data in the same way I used American Community Survey (ACS) data from the Census Bureau and data from the Census Bureau's Household Pulse Survey (HPS), to evaluate the affordability of UGI Gas rates, and to inform the Commission of consumer interests in decisions regarding return on equity, capital structure, rate design, and revenue requirement.

A basic tenet of utility ratemaking is that the Commission's decision should take into account not merely investor interests, but consumer interests as well. I specifically observed that under Pennsylvania law, in setting rates, the Public Utility Commission must give "due consideration to the interests of consumers."[17] In order to give "due consideration to the interests of consumers" as required by statute, the Commission must fully understand what comprise the "interests of consumers," including not merely the interests of low-income customers, but the interests of more moderate income customers as well.[18] Mr. Meilinger's assertion that "a base rate case. . .is simply not the appropriate

[16] Id.

[17] OCA Statement 6, at page 14, quoting 71 Pa. Stat. Ann. §309-5(2).

[18] Id., at pages 22, 23. ("As is evident from this discussion, the unaffordability of UGI Gas bills is not a problem that inheres exclusively in the low-income population of UGI Gas.") ("the problems that arise as a result of the

time to consider such a recommendation" is facially unreasonable and should be dismissed.

Q. WHAT IS YOUR NEXT RESPONSE TO MR. MEILINGER'S REBUTTAL TESTIMONY?

A. Mr. Meilinger objects to the use of a customer's access to COMPASS in order to establish a reasonable expectation that the customer is low-income. He offers a series of misleading objections that should be dismissed. First, he states that "for purposes of enrollment in the Company's Universal Service Programs, customers need to have their income verified."[19] That's true, but irrelevant. My recommendation on the use of a COMPASS screenshot was not for purposes of CAP enrollment, but rather for purposes of establishing Confirmed Low-Income status. Irrespective of the need for verified income for CAP enrollment, that is *not* needed to establish Confirmed Low-Income status.

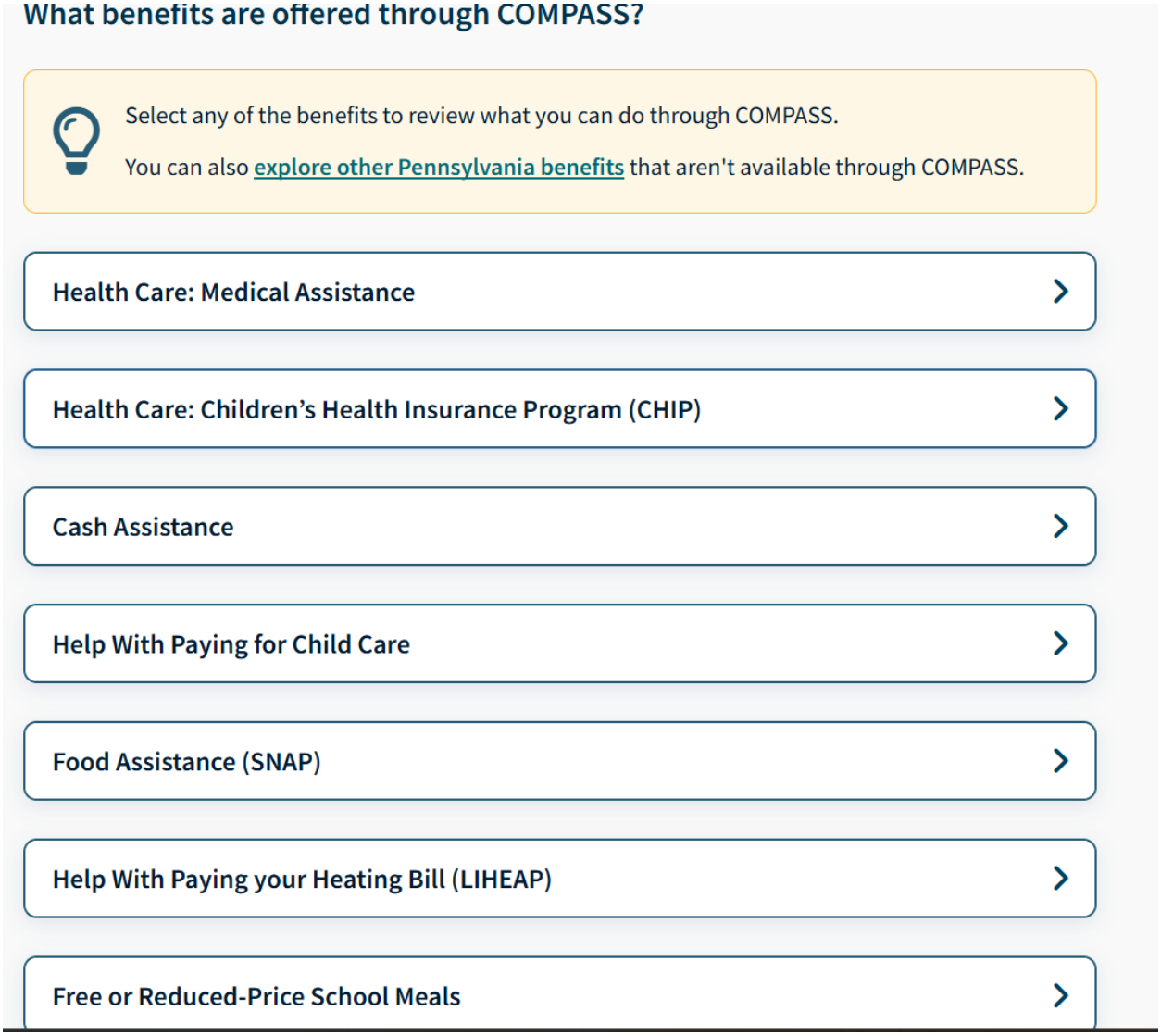
Second, Mr. Meilinger refers to a "screenshot of a COMPASS application."[20] It is not clear what Mr. Meilinger is referencing (or whether Mr. Meilinger even understands the proposal which he is objecting to). One does not apply for COMPASS. One instead can use COMPASS to apply for a range of benefits administered by the Pennsylvania

increasing unaffordability of UGI Gas bills for more moderate income UGI Gas households will be exacerbated even further by the rate hike sought by UGI Gas in this proceeding.").

[19] UGI Gas Statement 12-R, at page 21.

[20] Id. See also, UGI Gas Statement 12-R, at page 26 ("regarding Witness Colton's recommendation to use a screenshot or printout of the COMPASS application as part of the income verification process. . .").

Department of Human Services. The screenshot below is a partial listing of those benefits.



For purposes here, however, it is the additional services which COMPASS provides that would be helpful to UGI Gas if the Company would use it. As the screenshot below of the COMPASS website shows, one of the COMPASS "quick actions" is the ability of a household to track, in one place, their benefit application. Through this tracking, a household can establish what benefit programs they have been qualified for. A screenshot,

not of the COMPASS application, but of the list of programs for which the household has been qualified, would provide quick access to the list of programs. Contrary to Mr. Meilinger's testimony, use of COMPASS is the exact opposite of being "unnecessarily complicated." It would allow a customer to keep their actual income confidential, should they choose to do so, while still establishing their Confirmed Low-Income status.

Finally, Mr. Meilinger states that UGI Gas' acceptance of a COMPASS printout or screenshot is "unnecessary" because a household can "self-certify" their income. Again, intentionally or otherwise, his argument mixes up two different things. If a customer wishes to "self-certify" their income to their local utility, they should be allowed to do so to establish Confirmed Low-Income status. However, many households do *not* wish to provide a third party with information on their income, self-certified or otherwise. For *those* households, who for reasons of their own choosing, may wish to keep their income confidential, providing a COMPASS printout or screenshot would allow them to establish their Confirmed Low-Income status while keeping their income confidential.

The distinction here which UGI Gas seeks to draw is simply not permitted by Commission regulation. The distinction is between: (1) a customer demonstrating the *fact* of their low-income status without being required to disclose their actual income; and

(2) a customer being required to disclose, either through a certification process or through self-certification, what their actual dollar level of income is. UGI requires the latter, which is a requirement that cannot be found in the Commission regulation. A customer, for whatever reason of their choosing, may decide they do not wish to disclose their actual dollars of income to a third party.

Q. WHAT IS THE NEXT ASPECT OF MR. MEILINGER'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Mr. Meilinger misleads and mixes up –whether this is intentional or not does not detract from the fact that he is misleading and mixing up—the objections to what UGI Gas requires of a low-income customer in order for that customer to receive a deposit waiver or refund. First, he states that my testimony was wrong when I asserted that a customer must enroll in CAP to have their deposit waived. I made no such assertion. In fact, my Direct Testimony specifically quoted the UGI letter to a customer stating that "To have this deposit waived, you must have your income verified by completing the enclosed assistance application form. . . You do not have to enroll in CAP for the security deposit and any reconnection fees to be waived, but your stated income must still be verified through this process. . ."[21]

Having said that, nonetheless, UGI Gas *does require* a customer to apply for CAP and have their income verified as being eligible for CAP in order to qualify for the deposit exemption. The UGI letter could not be clearer: "to have this deposit waived, *you must*

[21] OCA Statement 6, at page 60. In addition, if a person receives LIHEAP, they qualify for a deposit waiver or refund. UGI Gas Statement 12-R, at 26.

have your income verified by completing the enclosed assistance application form." (emphasis added).

The prerequisite that UGI Gas imposes to qualify for a deposit refund or waiver simply cannot be clearer. The Company's shutoff notice, for example, state unequivocally: "If, based upon household income, *you are confirmed to be eligible for a customer assistance program*, a deposit is not required."[22] The fact that the Company might allow a customer to apply for, and be confirmed to be eligible for, enrollment in CAP, without actually deciding to enrollment after that application process, is offering, at best, a hyper-technical distinction. In imposing the requirement that a customer must apply for CAP and be certified as eligible for the program, UGI Gas goes beyond the scope of the regulation and in so doing violates the regulation.

In addition, Mr. Meilinger objects to what he references as my "recommendation to use a screenshot or printout of the COMPASS application as part of the income verification process. . ."[23] He argues that "screenshots and/or printouts of the COMPASS application are not available to customers."[24]As I explain above, there are two problems with his objection. First, it is not the "COMPASS application" which I propose be accepted as giving UGI Gas a reasonable expectation that a customer is low-income. Second, I do not propose to use the COMPASS screenshot or printout as part of an "income verification" process. To establish Confirmed Low-Income status, a customer is not, under the

[22] OCA-3-10 (emphasis added).

[23] UGI Gas Statement 12-R, at page 26.

[24] Id.

Commission's regulation, required to "verify" their income through an income verification process.

The question of using a COMPASS printout or screenshot should not be relegated to the UGI Gas USECP. Identifying a customer as being eligible for a waiver or exemption from a cash security deposit is not a "Universal Service Program." It is instead a consumer protection *mandated* by Commission regulation. Whether UGI Gas is unreasonably (and unlawfully) denying that consumer protection is not an issue which requires "various stakeholders" to "provide input on." It is not a matter of policy, it is a matter of compliance, which is unquestionably an appropriate issue for a rate case.

Finally, Mr. Meilinger argues that the current UGI Gas refund process is appropriate. He argues that "the Company has already implemented IT system processes to automatically release a security deposit once a customer has *gone through the income verification process*."[25] Having explained the impropriety of the required "income verification process," Mr. Meilinger's reliance on the inappropriate (and unlawful) process falls as well.

Q. DO YOU HAVE ANY FINAL OBSERVATION ABOUT MR. MEILINGER'S REBUTTAL TESTIMONY?

A. For reasons that are not clear, Mr. Meilinger takes exception to my observation that "there has not been sufficient time to determine whether UGI is complying" with the July

[25] UGI Gas Statement 12-R, at 27 (emphasis added).

2025 Settlement provisions of the previous UGI Gas base rate case.[26] My Direct Testimony was prefiled in April of 2026. He notes that I "do[…] not accuse UGI Gas of failing to comply with the settlement" and that my comments were "that is simply too early to assess the Company's compliance. . ." His response to my testimony regarding the rate case settlement addresses a non-issue. I will not further address whether actions taken less than two months ago are or are not in compliance with the settlement.[27] As I stated in my Direct Testimony, and as Mr. Meilinger acknowledges at some level, it is "simply too early" to assess what UGI Gas is or is not doing with respect to the July 2025 Settlement.

I note that UGI Gas seeks to have it "both ways" in the testimony of its rebuttal witnesses. On the one hand, Mr. Meilinger seeks to argue that the program implementation pursuant to the Settlement has been both adequate and meaningful. On the other hand, UGI Gas witness Fang acknowledges that:

> As Mr. Colton explains, participation barriers can materially limit affordability outcomes even where assistance programs exist, and Mr. Cicero similarly points to customers who remain unenrolled and exposed to payment difficulty. Read together, their testimony supports the conclusion that enrollment challenges are programmatic and structural in nature, not evidence that current rates are unjust or unreasonable. These concerns indicate the need for a broader examination of assistance program design and

[26] UGI Gas Statement 12-R, at pages 27 – 29.

[27] While Mr. Meilinger cross-references the Rebuttal Testimony of UGI Gas witness Adamo (UGI Gas Statement 13-R) as discussing settlement compliance, what he does ***not*** state is that Mr. Adamo's rebuttal testimony regarding settlement compliance is limited to a discussion of OCA witness Alexander's Direct Testimony. Mr. Adamo does not reference or respond to any testimony of mine regarding the 2025 Settlement.

> administration, which is more appropriately addressed through universal service program review rather than through base rate determinations. . .[28]

In this regard, the conclusions in Ms. Fang's testimony are closer to mine that the "don't look, there's nothing to see here" approach of Mr. Meilinger. Given the abbreviated time period between the Settlement of its last rate case, and the date on which UGI Gas filed yet another rate case, it is not possible. . .yet. . .to determine whether UGI Gas actions taken pursuant to the 2025 settlement are adequate or meaningful. No conclusions should be drawn about the implementation of those settlement provisions in this proceeding. In reaching this conclusion, I specifically limit my observations to the Settlement provisions regarding universal service outreach and enrollment. The Settlement provisions regarding customer service –e.g., the "updated field technician manual"—are addressed by OCA witness Barbara Alexander. I offer no opinions on that aspect of the 2025 Settlement.

Q. DO YOU HAVE A RESPONSE TO MR. MEILINGER'S REBUTTAL TESTIMONY WITH RESPECT TO ANY "INPUT" PROVIDED WITH RESPECT TO THE UGI GAS OUTREACH PLAN?

A. Mr. Meilinger criticizes my non-involvement with the review of the Company's presentation of its customer outreach plan developed pursuant to the July 2025 Settlement of the 2025 UGI Gas rate case.[29] His criticism, however, presents the Settlement provisions as though they organically arose. That criticism should be viewed in light of what really happened. There was a *reason* that there was a provision in the Settlement

[28] UGI Gas Statement 16-R, at page 28.

[29] UGI Gas Statement 13-R, at 23 – 24.

agreement regarding a need for UGI Gas to engage in more aggressive outreach to its low-income customers. The Settlement provision arose out of my testimony presented on behalf of the Office of Consumer Advocate documenting the need for additional action and more particular targeting. UGI Gas should not now be heard to assert that the basis for the Settlement Agreement can be ignored unless OCA again presents the factual foundation underlying the Settlement with which to begin. The testimony that gave rise to the Settlement should be the foundation of future discussions occurring pursuant to the Settlement.

Part 2. Response to UGI Gas Rebuttal Witness Daniel Adamo.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review and respond to the Rebuttal Testimony of UGI Gas witness Daniel Adamo as his testimony relates to my Direct Testimony.

Q. WHAT IS THE FIRST ASPECT OF MR. ADAMO'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Mr. Adamo responds to my testimony about the need for UGI Gas to eliminate its collection, use and retention, of customer Social Security Numbers (SSNs). His rebuttal testimony, however, is more notable for what it does *not* dispute than for what it does dispute. Mr. Adamo makes the explicit representation that "the Company does not share customers' SSNs with affiliates or corporate entities."[30] While UGI Gas shares "standards and policy programs for safeguarding customer personal information" across business

[30] UGI Gas Statement 13-R, at 15.

units, that sharing evidently does not imply that SSNs are also shared. Based upon Mr. Adamo's explicit unambiguous, unqualified statement that "the Company does not share customers SSNs with affiliates or corporate entities," my concerns on that single aspect of the use of SSNs has been addressed.

However, what Mr. Adamo did *not* dispute were my observations that UGI Gas:

- UGI Gas collects SSNs from 99.3% of its customers.
- The Company collects SSNs for the express purpose of providing them to a third party ("The Company asks for a new customer's SSN when they apply for service *so an Experian check can be run* to verify their identity."
- Experian's use of, and protection of, SSNs is not subject to the jurisdiction of the Pennsylvania PUC. Indeed, UGI Gas has no control over how Experian protects Social Security Numbers.
- Not only does the Company collect these SSNs, but it also retains them in perpetuity ("The tax ID further serves as a unique, persistent link between a customer and their account history. For this reason, it is retained on the customer record *even after service is discontinued*, preventing billing errors, duplicate accounts, and confusion arising from common names.")[31]

As I concluded in my Direct Testimony, which remains a valid conclusion, the Company's assertion that it collects SSNs "for the limited purpose of credit verification in connection with establishing utility service" is not an accurate statement.

[31] OCA Statement 6, at pages 71 – 72 (internal citations omitted).

Neither did Mr. Adamo dispute that when customers are asked to provide their SSNs at the time they apply for UGI Gas service, they are neither informed, nor notified, of the Company's intended retention and expansive use of the personal data. Mr. Adamo did not dispute the facts that UGI Gas:

- Does not inform or notify customers that their SSN will be retained in perpetuity, including after the time the household is no longer a customer of the Company;
- Does not inform or notify customers that their SSN will be provided to a third party (Experian), an international credit agency operating in North America, Central America, South America, Europe, the Middle East, Asia, and Australia.
- Does not inform customers of the fact that Experian will also appear to be authorized to retain customer Social Security Numbers. If Experian is not so authorized, there would be nothing for UGI Gas to match a customer SSN to in an "Experian Connect Check" in order to "verify the applicant's identity."[32]

Q. DID MR. ADAMO OBJECT TO YOUR RECOMMENDATIONS REGARDING THE COLLECTION, RETENTION, AND USE OF CUSTOMER SSNS?

A. Mr. Adamo's response was that I "provide[d] no specific recommendation about what should replace the use of SSNs. Thus, his recommendation is incomplete and does not require Commission action."[33] It is not OCA's responsibility to supply a "specific recommendation about what should replace the use of SSNs." The recommendation included in my Direct Testimony was specific and complete: that the Commission should direct UGI Gas to join in efforts to eliminate the collection, use and retention of SSNs.

[32] OCA Statement 6, at pages 72 – 73 (internal citations omitted).

[33] UGI Gas Statement 13-R, at page 15.

My recommendation was specifically that "UGI should be directed to report to the Commission, within 12 months of a final decision in this docket, its plan to eliminate the collection and retention of customer Social Security Numbers. This plan should include a plan for elimination of the SSNs currently retained in Company information technology."[34]

Mr. Adamo did not dispute, and indeed was aware of, the facts that:

- The National Academy of Science has concluded that industry and policy makers need to "reassess our perilous reliance" on SSNs.
- The Presidential Task Force on Identity Theft concluded that "more must be done to eliminate the unnecessary use of SSNs."
- The Federal Trade Commission (FTC) has urged a reduction in the use of SSNs in the private sector. FTC testified to Congress that there was a need to eliminate the unnecessary use of SSNs. The FTC cited the observation of the Presidential Task Force on Identity Theft that it is not clear whether the use of SSNs by the private sector was a necessity, or a result of "convenience and habit."[35]

Q. WHAT IS THE SECOND ASPECT OF MR. ADAMO'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Mr. Adamo disputes my recommendation that the Company's inclusion of its full set of claimed credit and collection expenditures be reduced to reflect a 50/50 sharing of those

[34] OCA Statement 6, at pages 75 – 76.

[35] OCA Statement 6, at page 67.

expenditures with ratepayers pursuant to Section 523 of the Public Utility Code. Section 523 states in relevant part: "The commission ***shall*** consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates under this title. On the basis of the commission's consideration of such evidence, it ***shall*** give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate." (emphasis added). Note that the statute is set forth in mandatory terms ("shall consider", "shall give effect").

Mr. Adamo presents no evidence that its credit and collection activity directed toward low-income customers is efficient, effective and adequate. The most that he asserts is that "the Company has repeatedly explained that collection practices are consistent with the requirements of 52 Pa. Code § 56.93—56.100."[36] In advancing this argument, however, Mr. Adamo seeks to change the statute. The mandatory "adjustments" referenced by the statute are not based on a need for the Commission to find non-compliance with specific statutory and/or regulatory requirements. Rather, the statute mandates ("shall give effect") an adjustment upon after a consideration ("shall consider") of the "efficiency, effectiveness and adequacy of service."

Moreover, Mr. Adamo attempts to write Section 523 out of the Public Utility Code by arguing that OCA's regulation would "ignore costs that are substantiated by record evidence and legitimately incurred."[37] This argument again ignores both the substance of

[36] UGI Gas Statement 13-R, at 18.

[37] UGI Gas Statement 13-R, at page 20

Section 523 and the mandatory language of Section 523. Mr. Adamo's argument would eliminate the very review which Section 523 makes mandatory. By arguing that costs are *ipso facto* "substantiated by record evidence and legitimately incurred," Mr. Adamo would preclude a Commission review of whether those costs are consistent with a finding of "the efficiency, effectiveness and adequacy of service. . ." Rather than making a showing of "efficiency, effectiveness and adequacy," and rather than seeking to rebut my showing to the contrary, Mr. Adamo argues that the very fact that costs were incurred makes them recoverable. The statute, however, provides otherwise. The statute provides that more must be shown, a showing that UGI Gas has not made.

In sum, Mr. Adamo's argument is insufficient to meet the showing that an adjustment is appropriate pursuant to Section 523.

Moreover, Mr. Adamo presents no information indicating that the 50/50 split used by OCA witness Jennifer Rogers is in error. Even though the UGI Gas data about its cost-of-service study presents a bigger dollar figure upon which to base an adjustment,[38] that number does not appear to be comparable to the number we propose to adjust. Elsewhere, UGI Gas states that the BCS dollars are merely "embedded" in its cost-of-service study.[39] Moreover, UGI Gas asserts that "a line-item correspondence to the specific BCS figures cited in the interrogatory cannot be made."[40] It further states that the BCS dollar figures are "not directly comparable to the Company's cost of service study,

[38] OCA-IV-7.

[39] OCA-IV-5.

[40] Id.

prepared on a fiscal-year basis."[41] I recommend continuing to use the number first presented by OCA witness Rogers.

Part 3. Response to UGI Gas Rebuttal Witness John Taylor.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine and respond to the rebuttal testimony of UGI Gas witness John Taylor as he purports to respond to my Direct Testimony.

Q. WHAT ASPECT OF MR. TAYLOR'S REBUTTAL TESTIMONY DO YOU WISH TO RESPOND TO?

A. The rebuttal testimony of UGI Gas witness John Taylor states in relevant part:

> Neither Witness Deupree nor Witness Colton provides Company-specific data or analysis demonstrating that lower-use residential customers are generally lower-income customers. Their criticism rests on a generalized assumption rather than evidence concerning the Company's actual customer population.[42]

Q. HOW DO YOU RESPOND?

A. It is not clear what part of my Direct Testimony in this proceeding Mr. Taylor is seeking to rebut. In my Direct Testimony, not only did I not provide "Company-specific data or analysis demonstrating that lower-use residential customers are generally lower-income customers," I provided no testimony at all on the extent to which lower-use customers are or are not generally also lower-income customers. Mr. Taylor states that my "criticism

[41] Id.

[42] UGI Gas Statement 11-R, at page 23.

rests on a generalized assumption rather than evidence concerning the Company's actual customer population." It is not clear what "criticism" of mine he is referencing. Not only did I present no "criticism rest[ing] on a generalized assumption rather than evidence," I presented no criticism at all regarding the relationship of usage and income. Mr. Taylor does not make the basis of his response any clearer by providing a citation to the part of my testimony to which his Rebuttal is responding.

In making this observation, I reserve the right to further respond to Mr. Taylor's "rebuttal" in the event that he identifies some specific aspect of my Direct Testimony to which his Rebuttal is responding.

Part 4. Response to UGI Gas Rebuttal Witness Cynthia Fang.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine and respond to the rebuttal testimony of UGI Gas witness Cynthia Fang to the extent that she addresses issues presented in my Direct Testimony. The Rebuttal Testimony of Ms. Fang has both methodological and policy problems with it.

Q. PLEASE EXPLAIN THE POLICY PROBLEMS YOU HAVE IDENTIFIED IN THE REBUTTAL OF UGI GAS WITNESS FANG?

A. Ms. Fang repeatedly states that the Commission should not consider the extent to which, if at all, UGI Gas rates result in unaffordable bills to residential customers. She asserts numerous times that the *only* purpose of utility ratemaking is to allow UGI Gas to recover

its prudently incurred costs.[43] She categorically dismisses bill affordability considerations as involving "macro-economic conditions"[44] which, she asserts, are beyond the purview of ratemaking.[45] In advancing this statement, she ignores the clear mandate of Pennsylvania statute. The Pennsylvania Public Utility Code provides that "Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable, and in conformity with regulations or orders of the commission."[46] In Pennsylvania, the Commission has repeatedly held that one aspect of "just and reasonable" is that rates are to be affordable as well.

Q. CAN AFFORDABILITY ISSUES BE DIVORCED FROM RATESETTING AS PROPOSED BY UGI GAS WITNESS FANG?

A. No. UGI Gas witness Fang urges that "broader macroeconomic affordability issues" are "more appropriately addressed through state and federal public policy tools that extend

[43] See e.g., UGI Gas Statement 16-R, at page 5 ("The Commission's statutory obligation is to ensure that utility rates are just and reasonable based on the prudent costs of providing utility service. . ."); see also, UGI Gas Statement 16-R, at page 11 ("The Commission should apply the established just-and-reasonable standard by evaluating whether the Company's rates are supported by the prudent costs of providing regulated service and are sufficient to allow the Company to continue providing safe, reliable, and compliant service to the public.").

[44] Ms. Fang refers to "macroeconomic conditions" 14 times in her 21 pages of Rebuttal Testimony.

[45] See e.g., UGI Gas Statement 16-R, at 21 (". . .the appropriate role of this proceeding remains to set just and reasonable rates based on the prudent cost of providing safe and reliable service, while broader macroeconomic affordability issues are more appropriately addressed through state and federal public policy tools that extend beyond utility regulation.")

[46] 66 Pa.C.S.A. Public Utilities § 1301.

beyond utility regulation."[47] Her effort to separate the consideration of "affordability" and the establishment of "just and reasonable rates" should not be accepted.

One factor Ms. Fang does not consider, for example, is the interrelationship of "affordability" and the costs which UGI Gas incurs. This connection is not merely recognized in Pennsylvania; it is recognized by rating agencies as well. Rating agencies such as Moody's, for example, look at payment patterns in their assessment of affordability. Moody's, for example, considers customer ability-to-pay "as measured by delinquencies."[48] Ms Fang paid no attention to UGI Gas delinquencies in her analysis. Had she done so, she would have observed troubling trends that should have called her to question her conclusion about the affordability of UGI Gas bills.

Indeed, affordability has increasingly become a major concern in setting the credit ratings of public utilities.[49] Citing the National Energy Assistance Directors Association (NEADA) report that "about one in six Americans are behind on their bills," Moody's was quoted as noting that fuel prices and economic factors "raise residential customer affordability issues. . ."[50] The Edison Electric Institute (EEI) ALSO publishes an annual

[47] UGI Gas Statement 16-R, at page 21.

[48] Arcadis (2017). Introduction to Affordability, at page 15.

[49] See e.g., S&P Global (March 11, 2025). White Paper: Affordability is Emerging as a Defining Issue for the U.S. Investor-owned Electric Utility Industry.

[50] Walton (Nov. 2022). "Moody's adopts negative outlook for regulated utility sector, warns on gas prices, economy and cost recovery," Utility Dive. See also, Mahajan (December 2023). Deteriorating Outlook for North American Utilities, Power and Gas in 2024 ("Affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures.")

"financial review," which review includes an examination of credit agency ratings.[51] Likewise, in its review of the Fourth Quarter of 2024, EEI reported that at the start of 2025:

> S&P maintained a negative outlook for regulated utilities, which it revised from stable in February 2024. Moody's maintained a stable outlook for regulated utilities. Fitch Ratings published a neutral sector outlook for North American Utilities. The agencies cited rising levels of capital spending, *customer bill affordability*, and extreme weather activity due to climate change as key themes they are watching.[52]

Similarly, in its Annual Financial Review for 2023, EEI specifically stated: "S&P noted that effective management of regulatory risk will be key to maintaining the industry's credit quality going forward. This will require. . . management of customer bill impacts."[53] EEI also said that Fitch maintained its deteriorating outlook in the sector in part because "customer affordability concerns will persist despite reductions in natural gas prices and inflation."[54]

In sum, Ms. Fang errs when she asserts, conceptually, that a ratemaking concern about affordability presents a threat to UGI Gas equity returns. Current concerns about affordability instead are common.

Q. IS MS. FANG'S TESTIMONY IN CONFLICT WITH ANY OTHER REBUTTAL TESTIMONY OFFERED BY UGI GAS?

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[51] While EEI is the industry association of electric utilities, similar concerns would apply to natural gas utilities as well.

[52] EEI (2025). 2024 Financial Review, at 26 (emphasis added).

[53] EEI (2024). 2023 Financial Review, at 22.

[54] Id., at 23.

A. Yes. Ms. Fang's testimony is in conflict with the rebuttal testimony of UGI Gas witness Meilinger. Mr. Meilinger testifies that:

> I disagree that it is appropriate to use [ALICE] data to analyze the impacts of the Company's rate case and/or its Universal Service Programs. The FPL guidelines are the standard indicator of a customer's income status and are used as such by the Commission and the Company. The FPL guidelines have also been used as a verification process to enroll customers into the Company's USECP. Witness Colton's recommendation to analyze ALICE data would be better suited outside of a rate case proceeding where various stakeholders, including the Commission and other community partners, would have the opportunity to provide input on his recommendations and consider the impacts of those recommendations.[55]

Unlike the ALICE data which Mr. Meilinger objected to, which data was not used to assess the Company's Universal Service Programs, or to evaluate impacts on low-income customers, the MHI data propounded by Ms. Fang is explicitly used to address the Company's Universal Service Programs and the affordability of UGI Gas rates to low-income households. Neither Ms. Fang nor Mr. Meilinger explain why my use of data not tied to Federal Poverty Level is inappropriate while Ms. Fang's use of data not tied to Federal Poverty Level is not. One difference in the use of the ALICE data which I present, and the MHI data which Ms. Fang presents, is that Mr. Meilinger specifically stated that he "{does] not dispute the ALICE data presented,"[56] while I find that the use of MHI data presented by Ms. Fang is inappropriate for all the reasons I discuss below.

[55] UGI Gas Statement 12-R, at page 6.

[56] UGI Gas Statement 12-R, at page 6.

Q. HAVE YOU BEEN ABLE TO COMPARE THE MEDIAN HOUSEHOLD INCOME FOR THE CENSUS BLOCK GROUPS IN THE UGI GAS SERVICE TERRITORY TO FEDERAL POVERTY LEVEL?

A. I have compared the Median Household Income for the Census Block Groups[57] in the counties served by UGI Gas to the Federal Poverty Level. I do so to assess the extent to which use of Median Household Income, at the Census Block Group level, reasonably reflects the population of households that would be eligible for UGI Gas Universal Service Programs. I matched data for 4,132 Census Block Groups.[58] For those Census Block Groups, the Median Household Income as a percent of Federal Poverty Level is set forth in the Table below.

The data in the Table above shows that the use of Median Household Income, even at the Census Block Group level, is an inappropriate metric to use to assess affordability for low-income customers. In only 131 Census Block Groups, was the MHI at or below 150% of Federal Poverty Level. In more than 4,000 CBGs, in other words, the MHI for the CBG would exceed the maximum eligibility level of the Company's Universal Service Programs (150% FPL). In more than 1,000 Census Block Groups, the MHI for

[57] Witness Fang testified: "Atrium Economics conducted a customer-level "gas burden" study, defining gas burden as the percentage of household income spent on the UGI gas bill, with household income proxied using American Community Survey ("ACS") data by mapping each customer to the median household income of the Census block group in which the customer resides. The analysis used customer billing and usage information for the period August 2024–July 2025 for gas only customers. Customers were then mapped to ACS 2024 5-year 3 block-group median income, and gas burden was calculated as annual gas bill divided by that income proxy." UGI Gas Statement 16-R, at pages 15 – 16.

[58] The Census Bureau does not report data for a Census Block Group if the population is sufficiently small that reporting data might present privacy concerns.

the Census Block Group would be more than 4.5 times higher than the maximum USP income eligibility.

Table 1. Count of Census Block Groups by Ratio of CBG Median Household Income to Federal Poverty Level

MHI as Percent of FPL	Number of CBGs with MHI at Ratio of MHI to FPL
<150%	131
150 % - 250%	636
250% - 350%	1334
350% - 450%	981
450% - 550%	503
550% - 650%	234
650% - 750%	140
750% - 850%	77
850% - 950%	50
>950%	46
Grand Total	4132

The data in the Table above shows how inappropriate it is to use Median Household Income to assess low-income affordability.

Q. PLEASE EXPLAIN THE "METHODOLOGICAL" PROBLEMS YOU HAVE IDENTIFIED IN MS. FANG'S ALTERNATIVE AFFORDABILITY ANALYSIS.

A. Ms. Fang states that she has undertaken an analysis of affordability using 454,815 gas-only UGI Gas customers. She states that based on her review of those customers, she identified a median gas usage of 723 ccf and a median bill of $1,105.[59] Those inputs, however, differ sharply from the data provided earlier by UGI Gas. When asked for the median UGI Gas bills for the most recent twelve months, provided in sufficient detail to

[59] UGI Gas Statement 16-R, at page 16.

allow replication, UGI Gas provided monthly residential bills that summed to a total of $1,215 (April 2025 through March 2026). Moreover, the "median use" underlying the bills provided by UGI Gas was 62.75 ccf per month (753 ccf per year).[60] UGI's previous data, in other words, reported higher bills at lower consumption than the results used by Ms. Fang. I will explain the significance of this difference in detail below.

Q. DOES MS. FANG'S "AFFORDABILITY ANALYSIS" INCORPORATE ANY OTHER FUNDAMENTAL METHODOLOGICAL FLAW?

A. Yes. Ms. Fang presents what she describes as an alternative affordability analysis of UGI Gas bill burdens throughout its service territory. She states that she matches UGI Gas customers with the Median Household Income (MHI) of the Census Block Group in which the customers in her sample reside. She does not attempt to justify the use of MHI as the income level by which she measures affordability.

Q. IS THERE REASON NOT TO RELY ON MEDIAN HOUSEHOLD INCOME AS THE FOUNDATION FOR AN AFFORDABILITY ANALYSIS?

A. Yes. Median Household Income was never intended to be used as the basis for assessing the affordability of utility service. Where it is used, it is a variation on MHI, not MHI itself. What the Environmental Protection Agency (EPA) recommends to assess water affordability is not Median Household Income but rather Median Household Effective Buying Income (MHHEBI). The MHHEBI sets forth the household median income after

[60] OCA-IV-44(a).

adjusting for taxes, residents face a combined federal/state/local tax rate of 19.82%.[61] Ms. Fang starts her analysis, in other words, with an income that is nearly 20% higher than what the MHHEBI would indicate is appropriate.

It is not merely the EPA, however, which use the "Effective Buying Income" as the appropriate metric by which to measure affordability. Credit rating agencies do so as well. For example, S&P uses MHHEBI in calculating its "Market Position Score" for utilities.[62] Indeed, one analyst for S&P Global Ratings writes that not only does S&P use Effective Buying Income,[63] but the use of this metric "should feel familiar" to those who follow the recommendations of the American Water Works Association (AWWA) and the Water Environmental Federation (WEF), given that these two water industry organizations use this metric as well.[64] In sum, where discussions have occurred in the utility industry –water, natural gas or electricity makes no difference—about which income is appropriate to use to perform an affordability analysis, it is the Effective Buying Income, not an unadjusted MHI, which has been used.

[61] https://smartasset.com/taxes/pennsylvania-paycheck-calculator (Federal income tax of 7.90%, state income tax of 3.07%, social security of 6.20%, Medicare of 1.45%).

[62] S&P, "Affordable for Now: Water and Sewer Raes at U.S. Municipal Utilities."

[63] Erin Burke, S&P Global Ratings (April 2020) "Rates and Affordability: A Ratings Agency Perspective," 4/3/2020, https://waterfm.com/rates-and-affordability-a-ratings-agency-perspective/. Accord, Arcadia (2017), "Introduction to Affordability, How is Affordability Measured" (S&P uses cost burden as percent of MHHEBI (income minus taxes and other deductions such as FICA).

[64] AWWA/WEF (2019). Developing a New Framework for Household Affordability and Financial Capability Assessment in the Water Sector."

Q. ARE THERE OTHER PROBLEMS WITH MS. FANG'S USE OF MEDIAN HOUSEHOLD INCOME AS THE BASIS FOR HER AFFORDABILITY ANALYSIS?

A. Yes. There are several additional problems. First, Ms. Fang uses a single number (the MHI) to represent income for everyone in each Census Block Group she uses to represent the UGI Gas service territory as a whole. This is wholly unhelpful and reveals very little, if anything, about the burdens felt by any people actually residing in the service territory. Use of the median for a geographic area not only hides the substantial differences between the residents of that geographic area, but also results in using the higher incomes of some persons to pull up the lower incomes of other persons, thus resulting in the wrong conclusion that rates are affordable throughout the area.

Ms. Fang's use of MHI for the entire population of each CBG implies that that income level encompasses the entire residential customer base in that area. MHI, however, does not encompass the entire residential customer base in a geographic area, CBG or otherwise. The "median" is a single point. It is the point at which half of the population has income that is greater than that point, with the other half of the population having income that is less.

The median of a geographic area, whether a state, a county, or a Census Block Group, is certainly not representative of the entire population in that area. It does not account for the inequality of incomes throughout the geographic area. The inequality of income is

measured by what is known as the "Gini Index."[65] A Gini Index of greater than 0.40 is considered to be an indicator of a substantial level of income inequality.[66] A high Gini Index is generally driven by a concentration of wealth in the upper incomes.

Ms. Fang may well have believed that CBGs are sufficiently small so that they would not have significant income disparities. However, the data demonstrates to the contrary. I have examined the GINI Index for all Census Block Groups in the counties served by UGI Gas. Of those 5,159 CBGs, 1,949 (38%, or nearly two-of-five) have a Gini Index of greater than 0.40.[67] An additional 1,698 CBGs in the UGI Gas counties have a GINI Index of between 0.35 and 0.40. Within the UGI Gas service territory, in other words, even within individual CBGs, use of the Median Household Income is an inaccurate representation of the total population given that the level of income is driven by a concentration of wealth in upper incomes. Even though the "median" may be the "middle" in terms of numbers, the middle is artificially high in terms of dollars of income.

[65] "The Gini Index is a summary measure of income inequality. The Gini coefficient incorporates the detailed shares data into a single statistic, which summarizes the dispersion of income across the entire income distribution. The Gini coefficient ranges from 0, indicating perfect equality (where everyone receives an equal share), to 1, perfect inequality (where only one recipient or group of recipients receives all the income). The Gini is based on the difference between the Lorenz curve (the observed cumulative income distribution) and the notion of a perfectly equal income distribution." https://www.census.gov/topics/income-poverty/income-inequality/about/metrics/gini-index.html

[66] https://blogs.worldbank.org/en/opendata/inside-the-world-bank-s-new-inequality-indicator--the-number-of-#:~:text=The%20new%20indicator,Saharan%20Africa%20and%20Latin%20America.

[67] American Community Survey (2024, 5-year data). Table B19083.

Q. IS THE INCOME INEQUALITY THAT YOU DESCRIBE SIMPLY A MATTER OF THE "RICH GETTING RICHER"?

A. No. The disproportionate growth of income at the highest income levels certainly contributes to an increase in the Median Household Income over time. However, that disproportionate growth is not the exclusive trend which is affecting the problem which I identify in the use of MHI for the purposes which Ms. Fang wants to use it.

The Federal Reserve Bank of Cleveland recently prepared an analysis of the seeming growth in Median Household Income.[68] According to these Federal Reserve researchers, households today are smaller, older, and more educated than they used to be, with higher incomes which pull the MHI up. The Federal Reserve researchers reported: "Because older and more educated people tend to have higher incomes than younger and less-educated people, these demographic shifts could raise the median income, without necessarily indicating that any particular group is better off."[69] Thus, the Federal Reserve recognizes the impact that I noted above that households with higher income – in this case households that are older and more educated – pull the MHI upwards even though that income growth is not generally shared. Ms. Fang's MHI certainly does not encompass the entire residential customer base as she would have us believe from her analysis.

[68] Dohrman and Fallick (2020). Is the Middle Class Worse Off than it Used to Be?, Federal Reserve Bank of Cleveland, available at https://www.clevelandfed.org/publications/economic-commentary/2020/ec-202003-is-middle-class-worse-off.

[69] Id., at 2.

Q. HAVE YOU HAD AN OPPORTUNITY TO PREPARE AN AFFORDABILITY ANALYSIS FOR THE RESIDENTIAL CUSTOMER BASE FOR UGI GAS AS A WHOLE?

A. Yes. In my analysis, I use the usage and billing data requested from, and provided by, UGI Gas through its discovery responses. I recommend that the Commission use the methodology proposed by Patterson and Doyle. Writing in the October 2021 issue of the American Water Works Association's (AWWA) "Water Science", they explored "multiple affordability metrics within and across utilities."[70] After explicitly rejecting sole reliance on the median income as being non-representative, they recommend use of an "HB Score" ("HB" representing "household burden") for the service territory. The Patterson/Doyle analysis is based on readily available public information available through the annual American Community Survey published by the Census Bureau. I calculate the "HB Score" in four steps:

- Using the average UGI Gas usage and bill (as reported by UGI Gas),[71] I calculate for each zip code the UGI Gas burden separately for each income range for households.[72] For each income range, I use the mid-point to represent that income range (e.g., for the income range $10,000 to $14,999, I use the mid-point of $12,500).

[70] Patterson and Doyle (October 2021). Measuring water affordability and the financial capability of utilities, AWWA Water Science.

[71] OCA IV-44(a).

[72] Income ranges are provided in the American Community Survey (Table B19001).

- I calculate a weighted household water burden for each income range within a zip code by dividing the number of households in each income range by the total number of households in that zip code and multiplying that weight times the burden for that income range.
- I calculate the weight for each zip code by dividing the number of residential UGI Gas customers in that zip code by the total number of UGI Gas residential customers.
- I finally calculate the weighted burden for each zip code by multiplying the burden for each zip code times the zip code's weight.

Given those preliminary steps, the service territory HB Score is the sum of the weighted burdens for all zip codes within the service territory.[73] As Patterson and Coyle do, I present the service territory HB Score as the weighted average.

For UGI Gas, the weighted average HB Score at existing rates is a natural gas burden of 3.3%, nearly two-and-a-half times higher than what Ms. Fang reported finding. Contrary to what Ms. Fang argues, this data, in I find that there are serious affordability problems facing UGI Gas customers, even at current rates. The rates sought by UGI Gas in this proceeding would increase those problems even more.

Q. DOES USE OF THE PATTERSON AND DOYLE APPROACH HAVE ANY ADDITIONAL ADVANTAGE OVER MS. FANG'S TESTIMONY?

[73] This is nearly identical to Ms. Fang's calculation. While Ms. Fang uses data for Census Block Groups, I use zip codes because, while Ms. Fang did not identify which CBGs she used to define the UGI Gas service territory, UGI Gas has previously provided the zip codes which comprise its service territory.

A. Yes. Ms. Fang concedes that her review of affordability excludes an entire population for whom affordability presents the greatest issue, the population reporting an income of $0.[74] Ms. Fang's proposed methodology simply cannot arithmetically address the affordability issue of this population. Rather than seeking to accommodate those households, Ms. Fang simply excludes them entirely. In contrast, the Patterson/Doyle approach I use above takes into account households at all income levels.

Q. DO YOU HAVE ANY FINAL COMMENTS ABOUT MS. FANG'S REBUTTAL TESTIMONY?

A. UGI Gas witness Fang presented an affordability analysis specific to low-income customers. Using the CAP Credits and CAP Bills as the basis for determining what low-income UGI Gas burdens would exist in the absence of CAP, and what impacts CAP has in addressing those unaffordable burdens, Ms. Fang's testimony found that:

> CAP benefits materially reduce gas burden, shifting the distribution downward: mean gas burden falls from 13.02% without benefits to 5.85% with benefits, with similar reductions at the median (7.60% to 5.47%) and the upper tail (95th percentile 26.39% to 7.18%). Overall, the with-benefits distribution is more concentrated at lower burden levels, indicating that CAP benefits substantially mitigate both typical burdens and high-burden outliers, although a small number of customers still experience high gas burdens.[75]

Despite these substantial benefits provided through CAP, Ms. Fang argued that every single proposed improvement in CAP outreach and enrollment for UGI Gas should be denied. She opposed every recommendation for improved outreach and targeting despite

[74] UGI Gas Statement 16-R, at page 20.

[75] UGI Gas Statement 16-R, at pages 21 -22. These benefits were found even after excluding 10% of the total CAP population because they reported $0 in income.

the fact that her own Rebuttal Testimony concluded that her analysis "support continued focus on the effectiveness accessibility, and coordination of the Commission's universal service programs for customers most in need."[76] The grounds for her opposition was her assertion that the concerns raised by myself and CAUSE-PA witness Cicero "indicate the need for a broader examination of assistance program design and administration, which is more appropriately addressed through universal service program review. . ."[77] In Pennsylvania, however, the Commission has repeatedly made clear that the operation of universal service programs, with a specific emphasis on CAP, are appropriate issues to be addressed in a base rate proceeding. In fact, the low-income affordability analysis presented by Ms. Fang in her rebuttal testimony supports, and does not rebut, the need for the improvements I recommend in my Direct Testimony. Her personal belief that such issues would be "more appropriately addressed" in a different forum is at odds with Commission precedent and should be rejected as a grounds for opposing the recommendations which I advance.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE REGULATORY COMPACT BETWEEN RATEPAYERS AND THEIR LOCAL UTILITY?

A. Yes. Ms. Fang testifies that "the parties misconstrue the scope of utility regulation." She then makes two references to "state law." First, Ms. Fang asserts that "the Commission's *statutory obligation* is to ensure that utility rates are just and reasonable based on the

[76] UGI Gas Statement 16-R, at page 26.

[77] UGI Gas Statement 16-R, at page 28.

prudent costs of providing utility service."[78] In making this statement, Ms. Fang does not cite the state statute which imposes this "statutory obligation," let alone a state statute which provides that this is the sole or exclusive obligation of the Commission. In fact, in Pennsylvania, as I note above, state law explicitly provides that, in setting rates, the Public Utility Commission must give "due consideration to the interests of consumers."[79] In addition, the statute creating the Office of Consumer Advocate, on whose behalf I am testifying in this proceeding, explicitly provides that

> In addition to any other authority conferred upon him (sic) by this act, the Consumer Advocate is authorized, and it *shall be his duty*, in carrying out his responsibilities under this act, to represent the interest of consumers as a party, or otherwise participate for the purpose of *representing an interest of consumers*, before the commission in any matter properly before the commission. . . The Consumer Advocate may exercise discretion in determining the interests of consumers which will be advocated in any particular proceeding and in determining whether or not to participate in or initiate any particular proceeding and, in so determining, *shall consider* the public interest, the resources available and *the substantiality of the effect of the proceeding on the interest of consumers*.[80]

It would make no sense for the legislature to statutorily impose a duty ("shall be his duty") to represent the interests of consumers, and in so doing, impose the further statutory duty ("shall consider") to consider the "substantiality of the effect of the proceeding on the interest of consumers" if, as opined by Ms. Fang, the exclusive authority of the Commission is to "ensure that rates are just and reasonable base don the prudent costs of providing utility service."

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[78] UGI Gas Statement 16-R, at 5 (emphasis added).

[79] OCA Statement 6, at page 14, quoting 71 Pa. Stat. Ann. §309-5(2).

[80] 71 P.S. § 309-4 (emphasis added).

Aside from the explicit statutory language, utilities and the commissions that regulate them, have a far broader mandate than that asserted by Ms. Fang. Aside from the comments of Ms. Fang, historically, public utility companies such as UGI Gas have had imposed upon them by common law an "obligation to serve." This obligation to serve arises from a utility's dedication of its property to a public use. Declarations in the corporate charter and other words or actions which represent a dedication to the public use would result in the creation of an obligation to serve. So, too, would actions such as accepting franchises from state and local governments or making a commitment by contract (such as by accepting public funds or other perquisites).

Persons who seek universal service can not rely upon a competitive market to deliver such results. By its nature, a competitive market tends not only to exclude those most in need, but tends to increase prices to those least able to pay. The essential characteristic of the marketplace is that it allocates goods and services on the basis of the ability to pay rather than on the basis of the need for the service. The market, therefore, excludes those who are unable to afford the service being sold. By the nature of markets, those who are unable or unwilling to pay the price of the commodity are left out. The harm arises not from a market that does not work, but rather from a market that *does*. Inclusiveness of customers through the pursuit of universal service is not a goal which a competitive market recognizes. Conversely, exclusion is not necessarily considered a market failure.

This is not to indicate that industry participants in a competitive market harbor ill will or caprice toward consumers unable to pay. Instead, the failure to pursue

universal service is based on decisionmaking considered to be not only rational by the industry, but dictated by the economics of the industry and its consumers.

The role of a state utility commission is to stand between the utility and consumers, thus preventing these unfettered impacts of an unregulated public utility.

One key element of a utility's common law duty to serve is its total independence from any statutory basis. The duty of a public utility is one implied at common law and need not be expressed by statute, or contract, or in the charter of the public utility. The duty to serve is an integral aspect of public utility status. American courts imposed such a duty long before the establishment of comprehensive regulation of utilities pursuant to statutes.

It is for these reasons that Pennsylvania statutes explicitly provide that the Public Utility Commission, in setting rates, must give "due consideration to the interests of consumers."[81] It is for these reasons that Pennsylvania statutes created the Office of Consumer Advocate, mandated that the OCA to "represent the interest of consumers" and further mandated that, in pursuing that representation, the OCA, "shall consider. . .the substantiality of the effect of the proceeding on the interest of consumers."[82]

Ms. Fang's testimony to the contrary should be rejected.

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[81] OCA Statement 6, at page 14, quoting 71 Pa. Stat. Ann. §309-5(2).

[82] 71 P.S. § 309-4 (emphasis added).

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division
:

VERIFICATION

I, Roger Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 6SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: /s/ *Roger Colton*
Roger Colton

Address: Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

OCA STATEMENT 7

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
UGI Utilities, Inc. – Gas Division	**)**	**Docket No. R- 2025-3059523**
	)	
	)	

TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 13, 2026

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OCA Exhibit ZT-1 – Curriculum Vitae of Zach Teti

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zach Teti. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. degree in Economics from Millersville University (Millersville, PA) in 2013 and an M.S. in Energy Economics from Pennsylvania State University (University Park, PA) in 2021.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have twelve years of experience in the banking and energy industries, most recently specializing in organized wholesale and retail electricity markets. My background comprises energy market design and analysis; econometric research in an academic setting; and financial planning, analysis, and control in a banking setting. I was employed as a Senior Regulatory Analyst serving as a representative of the NEPOOL Markets Committee between 2021 and 2024, analyzing wholesale electricity market design and its impact on default service procurement of electricity. Since joining the OCA as a Senior Regulatory Analyst in April 2025, I have been focusing on a variety of topics including the wholesale electricity markets of PJM, utility rate cases, and default service plans for electricity procurement.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS TESTIMONY?

A. I am offering this testimony on behalf of the OCA. My testimony is intended to address issues from the standpoint of residential customers of gas services.

Q. DO YOU HAVE ANY APPENDICES OR EXHIBITS TO YOUR TESTIMONY?

A. Yes, my Curriculum Vitae is included herein as Exhibit ZT-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony amplifies the concerns and lived experiences of residential customers and government officials expressed during public input hearings regarding the proposed rate increase requested by UGI Utilities, Inc. – Gas Division ("UGI" or "Company") slated for implementation in 2026. These voices consistently underscore serious affordability challenges associated with the increase. Participants also raised credible concerns about a perceived imbalance favoring shareholder interests over those of customers, as well as related issues including the burden placed on residential customers by rising data center demand, construction mismanagement, the need for meaningful consideration of climate change, and ongoing customer service shortcomings.

Q. DID THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC OR COMMISSION) CONDUCT PUBLIC INPUT HEARINGS FOR THIS PROCEEDING?

A. Yes, the Pennsylvania Public Utility Commission (PUC) conducted twelve Public Input Hearings to gather testimony from ratepayers and public officials to better

understand the impact of the proposed rate increase.[1] On Monday, March 30, 2026, two in-person Public Input Hearings were held at the Manheim Township Public Library in Lancaster, PA. On Wednesday, April 1, 2026, two in-person Public Input Hearings were held at the Wilkes Barre Township Fire Department Fire Hall in Wilkes Barre, PA. On Monday, April 6, 2026, two in-person Public Input Hearings were held at the City of Allentown Council Chambers in Allentown, PA. On Tuesday, April 7, 2026, two in-person Public Input Hearings were held at the Dunn Community Center in Reading, PA. Additionally, two telephonic hearings were held on Friday, April 3, 2026. At the public input hearings, a total of 16 customers and 8 public officials testified. My testimony focuses on public input hearing testimony that may be pertinent to the OCA's overall recommendations set forth in the OCA's Direct Testimony filed on April 13, 2026.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section I is an introduction. Section II presents a summary of testimony related to the affordability issue. Section III presents a summary of other issues, such as the adverse impact of data center demand on residential customers, mismanagement of construction, climate change, and customer service.

Q. OVERALL, DOES THE PUBLIC RECOMMEND THAT THE COMPANY'S PROPOSED RATE INCREASE BE APPROVED BY THE PUC?

No. The public's overall sentiment is one of clear and genuine concern. On a personal note, as an economist focused on energy market structure and policies that affect rate-paying customers, reviewing this input has been eye-opening. It has meant stepping

[1] My testimony focuses on the first ten, attended public input hearings to date and for which transcripts have been made available. I will be supplementing my direct testimony on or about April 21, 2026 and upon receipt of further transcripts.

back from my usual reliance on data and abstract analysis and instead taking the time to listen to—and understand—the very real concerns and reactions people have to this proposed rate increase and just how untenable another rate increase is for the service territory.

II. AFFORDABILITY: CUSTOMERS ARE STRUGGLING TO PAY THEIR BILLS

Q. HOW MANY PEOPLE FROM THE PUBLIC TESTIFIED ON THE TOPIC OF AFFORDABILITY?

A. Among the twenty-four people from the public who testified, affordability concerns were raised twenty-one times. The ability to afford utility bills is a problematic issue raised by three out of five people who spoke in Lancaster, eleven out of twelve people who spoke in Wilkes-Barre, each of the two people who spoke in Reading, and each of the five people who testified telephonically. For some and perhaps many, living in the areas served by the Company is either difficult to afford or unaffordable. As stated by Witness William Davis, "You can only wring so much water out of a wet rag before there's nothing left to get out of it and we would also find ourselves in a situation of where we may have to consider selling our home and maybe even moving out the of state with family because the cost of living has become too prohibitive." (Transcript P. 233-234)

Q. PLEASE SUMMARIZE THE REMARKS OF THE WILKES BARRE CITY CONTROLLER REGARDING AFFORDABILITY.

A. Witness Tony Thomas is the Wilkes Barre City Controller, tasked with financial oversight of the local government and its municipal operations. Witness Thomas remarked, "When you consider the income levels of an area like Wilkes Barre City, the poverty levels, $10 on top of other mounting costs in this Commonwealth, in this

country, whether that be rising gas prices, rising costs of other utilities, $10 might be a lot of money to certain individuals." (Transcript P. 233-234) The estimated residential customer charge is expected to increase by $10 per month.

Q. HOW ARE RESIDENTIAL CUSTOMERS RESPONDING TO THE COMPANY'S PROPOSED AVERAGE $10 PER MONTH INCREASE?

A. In my reading of remarks made by the various residential customers, consumers are:

- **Frightened:** "The thought of the pricing going up eight percent. I'm starting to look at what being unemployed in retirement looks like and it's very scary actually. I thought I was fine. I am finding I'm not as fine as I thought." (Transcript P. 62)
- **Perplexed and Bothered:** "What is their normal revenue? How much money do they need? I mean this is inflicting some hardship on people, especially retired people like myself." (Transcript P. 64)
- **Dismayed:** "So, what are we supposed to do? And I don't understand why we need this increase. And that's pretty much what I would like to say, because we work and work with all the other bills, and it's too much. The cost of living is too much for us." (Transcript P. 118)

Q. RELATEDLY, HOW DO CUSTOMERS FEEL ABOUT THE COMPANY'S RELATIONSHIP WITH CUSTOMERS VERSUS SHAREHOLDERS?

A. Public input reflects a growing sense of financial strain, fear, and frustration among customers facing rising costs. Many individuals—particularly those on fixed or limited incomes—describe deep anxiety about their ability to remain financially secure, with some questioning whether they can sustain basic living expenses into retirement. Across testimonies, there is a strong perception of unfairness: customers feel burdened by increasing rates while companies report substantial profits, shareholder payouts, and

high executive compensation. This has led to a broad sense of distrust with many questioning whether corporate priorities are aligned with the needs of the public. Taken together, these voices underscore not only the economic pressure households are experiencing, but also a growing concern that the system is leaving ordinary consumers behind.

- **Used: "**You know, if [the Company] is giving all these dividends out, they're not giving the dividends out, we're giving the dividends out, because we're the ones stuck paying for all this stuff. And we just cannot afford no more." (Transcript P. 134)
- **Jaded:** "And the cost of living right now is so extremely high that I believe that maybe, just me, their shareholders might miss a dividend payout. So that way the average person can pay their bills and feel a little bit safer in the winter." (Transcript P. 170)
- **Agitated: "**Meanwhile, their own press releases, 2024 press releases that they made record profits. In fact, they sent $318 million to their shareholders while their average executives make $1.15 million. They say that they need this increase for upgrades and improvement. Why aren't there upgrades and improvements baked into their business model? Why weren't these profits put back into their own business? Why are they being passed on to us, the consumer?" (Transcript P. 164)

Q. PLEASE NOTE THE REMARKS OF THE MAYOR OF SCRANTON REGARDING AFFORDABILITY.

A. Mayor Paige Cognetti of Scranton, PA, discussed the additive and substantial nature of this proposed rate case compounding alongside other very recent utility rate increases. Looking back as near as 2021, "total [rate increases] represented an increase of $426.75 million for those utilities represent an increase average about $78 per month for a residential customer or more than $900 a year." (Transcript P. 128) Mayor Cognetti

also discussed pending requests to offer a total of "$1,746 annually for a household to bear these increased costs if all of these rate increases are approved from this last five years." (Transcript P. 129) Later that evening, Witness Christina Daniels spoke to the same five-year timeframe, "I myself, I can't speak for others, but I'm blessed. I'm married. My husband works 60 hours a week to help provide, but I too have to work 65 hours a week to provide for our family. And these costs are just getting out of hand every month. We're making it and we don't have savings. We have one car payment. We're blessed to have one paid off. Every one of our utilities is going up and we just can't absorb the cost anymore. I mean, if we haven't been on a vacation in five years." (Transcript P. 128) Witness Daniels thankfulness is a humble surrender, an unfortunate submission; to me, it seems she is requesting relief just so she can keep up the existence of her and her family – and this request is not unique. Mayor Cognetti continued, "You've heard from residents and certainly, as Mayor of the city, I speak with residents all the time who are really, really struggling to make ends meet. We cannot bear these increases." (Transcript P. 129)

Q. PLEASE SUMMARIZE THE REMARKS OF OTHER PUBLIC OFFICIALS AND SERVANTS.

A. The testimony presented at the public input hearings paints a consistent strain, frustration, and inequity among customers. The public officials and servants who testified describe households forced into impossible tradeoffs—choosing between food, medication, and heat—not as rare exceptions, but as everyday realities for their neighbors. These accounts make clear that many customers are already beyond their financial limits, with even modest increases pushing them further toward crisis.

At the same time, speakers question whether the Company's cost structures and reliance on assistance programs reflect prudent decision-making or instead shift

burdens in ways that mask the true unaffordability of service. Others point to a growing sense of anger and distrust, with ratepayers feeling treated as an "open checkbook" while struggling to meet basic needs.

Finally, testimony highlights a perceived disconnect between strong financial outcomes for shareholders and the lived experience of customers who see little of that benefit. Collectively, these voices call into question not only the timing of the proposed increase, but also whom the utility ultimately serves—and whether sufficient weight is being given to the communities that bear its costs.

The public officials who testified at the public input hearings had this to say:

- Witness Kimberly Krupsha, Public-Facing Civil Servant: "I hear people tell me about impossible choices they face. Food versus medications, medications versus heating the homes. I hear from people who are on the verge of eviction not because of their irresponsibility but because of the cumulative weight of housing costs, food costs, rising utility bills that simply are more than any fixed or modest income can bear. These are not edge cases or statistical outliers. These people are my neighbors, and I encounter them every day." (Transcript P. 172-173)

- **Witness Chris Belles, Luzerne County Council:** "There are a lot of families that rely on essentially what is a commodity that can't afford any percent increase. They can't even afford it as it is. And yes, there are government programs to help them, but then that is just socialism that's keeping the price is, you know, afloat for UGI to charge everybody else more." (Transcript P. 158)
- **Witness Jamie Walsh, Representative:** "Every time we do a rate increase, the people that are on a fixed income are having a really, really difficult time making ends meet. And we're not talking about spending that they can just go out to dinner. This is food

on the table… Let me be clear. People in our region are extremely angry right now. They're angry at all the utility companies, because they just feel like the ratepayers are an open checkbook for them." (Transcript P. 120-121)

- **Witness Nikki Rivera, State Representative:** After reading the financial report of the Company, "Yay, shareholders. However, those who are paying the bill each month would like some of that same benefit in their pockets. So, I ask that you reject the proposal and side with our UGI customers." (Transcript P. 86)
- **Witness Judith Schwank, State Senator: "**We're living in a time of economic turmoil and uncertainty, and I know very many of my constituents are concerned. Frankly, I know that very many of my constituents are afraid of what is in store economically, to say the least. I'm extremely concerned that we're discussing substantial rate increase during such trying times." (Transcript P. 284)

III. OTHER CONCERNS

A. Data Center Demand

Q. PLEASE NOTE THE CONCERNS REGARDING DATA CENTERS SHARED BY WITNESS NATHAN EACHUS.

A. Witness Nathan Eachus provided cogent fears about the contemporary state of affairs in the energy-industry as it pertains to data centers. Witness Eachus stated, "Residents have described an eight percent rate increase as colossal and unaffordable, especially for retirees and fixed income households who are already making difficult choices just to get by. This is immediate and real. At the same time, Pennsylvania is seeing rapid expansion of high energy users, particularly data centers. These facilities require massive amounts of diesel, methane gas, electricity infrastructure and evidence that shows data center demand is driving up energy costs systemwide, including capacity prices and grid expansion costs. Without proper safeguards, those costs are shifted onto

the ratepayers." (Transcript P. 179-180) After articulating the exacerbated stresses of the industry by data canter demand, Witness Eachus continued, "This raises a fundamental fairness issue. Why are residents being asked to pay more while large industrial users like data centers are increasing demand? Recent policy discussions in Pennsylvania recognize this imbalance and are moving toward requiring data centers to pay their own way rather than passing costs onto households." (Transcript P. 181)

Q. PLEASE NOTE THE CONCERNS REGARDING DATA CENTERS SHARED BY WITNESS FERN LEARD.

A. Witness Fern Leard observed, "We are also seeing growing energy demands from AI data center developments and we know it is not just electricity that powers these facilities. They also rely on natural gas. That means more pressure on both systems and more infrastructure being built to support them. This proposal feels like families are being asked to pay first while massive new energy users get to come online later." (Transcript P. 185-186)

Q. PLEASE NOTE THE CONCERNS REGARDING DATA CENTERS SHARED BY REPRESENTATIVE JAMIE WALSH.

A. Representative Jamie Walsh requested, "One of the things that I would like the Commission to look into as well is what percentage of this increase is being allocated to support the data center industry, because I think that is extremely important. Ratepayers should not be supporting any infrastructure that is going to supply energy to these data centers. They need to provide their own and they need to pay their own way." (Transcript P. 138-139)

B. Mismanagement of Construction and Customer Service

Q. PLEASE SUMMARIZE THE INCIDENT SHARED BY WITNESS IVAN RITZ.

A. Witness Ivan Ritz discussed a localized nightmare, a calamitous anecdote of construction mismanagement and customer inconsideration. “Five months of noise, dirt, debris, trying to find a parking space and the constant pounding of vehicles going over settling trenches,” he stated. (Transcript P. 89) When the project was initiated, the work did not come as a surprise, “We knew it was coming,” but the style of work was unfortunately not commendable, “The great American work ethic was never on display.” (Transcript P. 88-89) The anecdote involves major mishaps, “[A supervisor from Verizon] responded that the contractor for UGI had severed [Verizon’s] fiber optic cables and they were trying to determine where and how often. He explained to me that it was very difficult to locate the cable breaches because the cables do not carry any electrical current.” (Transcript P. 90) The second mishap feels inexcusable, “One of the cable ruptures was caused by the installation of my new gas line. They opened the trench out front and determined - and also determined that my new gas line was leaking.” (Transcript P. 90) To fix this, “They had to shut off the gas to the house while they replaced the line. And when they were finished, they didn't have time to relight the pilots because their shift had ended.” (Transcript P. 91) In the aftermath, Witness Ritz wonders who will bear the cost, “Someone really dropped the ball here. Maybe this happens often, I do not know. But if UGI is responsible for the cost. I prefer not to help them pay for it.” (Transcript P. 92)

C. Climate Change

Q. PLEASE NOTE THE CONCERNS REGARDING CLIMATE CHANGE SHARED BY WITNESS ELISABETH HOFFMAN.

A. Witness Elisabeth Hoffman is concerned that, "Utilities finance the spending and they collect the cost plus profit from the customers over many decades. And the more money the utilities spend on these capital assets, profit they stand to earn. And so, the gas companies end up having a powerful profit motive to maintain the status quo of accelerated spending on gas infrastructure. And that in turn is going to wed us for decades to using more gas when we need to be shifting to renewable energy. So, I'm wondering if the PUC can require that UGI prioritize replacement of aging pipelines based on their risk to the public and can they require evaluation of alternatives to replacement like leak detection or something else? I realize that we need to keep pipelines safe, but overspending on new infrastructure doesn't make sense when we need to be moving off of fossil fuels because of climate destruction and health reasons and cost reasons. Every dollar spent on new infrastructure is a dollar we're not spending on renewable energy." I agree that progressing sustainable, renewable energy infrastructure should be a considered topic in each utility rate case.

IV. REVIEW OF WRITTEN COMPLAINTS

Q. WHAT IS THE COMMON CONCERN RAISED IN WRITTEN COMPLAINTS?

A. There were thirty-three written complaints filed regarding UGI's proposed rate increase. The common concern raised in formal complaints is consistent with the common concern raised at the public input hearings: affordability. For example, Richard and Kandie Hambidge said, "If we have to make repairs or update our home

we can't go to our boss and demand a raise. We have to go to our savings, get a loan, or take on an additional job. As senior citizens, we have a fixed income but we each have a job just to keep up with constantly increasing utility prices."

More desperately, Susette Higdon stated, "Last month's bill, $463 – thermostat on 72 degrees. I'm 78 years old and I freeze. I wear two sweatshirts, heavy sweatpants, socks and gloves…sometimes a coat and I freeze. Can't afford to raise temp and can't afford $463, more. No increase please, not 8.7%."

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF ALL OF THE PUBLIC INPUT HEARING TESTIMONY?

A. In my opinion, UGI's customers and public officials are clearly opposed to any rate increases at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OCA STATEMENT 7

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
UGI Utilities, Inc. – Gas Division	**)**	**Docket No. R- 2025-3059523**
	)	
	)	

EXHIBIT TO THE

TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 13, 2026

CURRICULUM VITAE OF ZACH TETI

PROFESSIONAL EXPERIENCE

Pennsylvania Office of Consumer Advocate • Harrisburg, PA • April 2025-Present • Senior Regulatory Analyst
Customized Energy Solutions • Philadelphia, PA • April 2024-September 2024 (Contract) • Compliance Analyst
Avangrid • Orange, CT • May 2021-April 2024 • Regulatory Analyst – FERC, ISO New England & New York ISO
Penn State University • University Park, PA • August 2019-May 2021 • Research Assistant – Energy Economics
TD Bank • Mount Laurel, NJ • February 2018-July 2019 • Assistant Vice President – Retail Lending Financial Analysis
JP Morgan Chase • Newark, DE • July 2013-February 2018
Budgeting, Forecasting and Analysis - Associate – Consumer Banking Technology • July 2017-February 2018
Financial Control – Associate & Analyst – International Trade Finance • July 2013-July 2017
Lancaster County Workforce Investment Board • Lancaster, PA • December 2012-May 2013 • Research Intern

EDUCATION & OTHER UNDERTAKINGS

Penn State University • University Park, PA • May 2021 • MS in Energy Economics
Millersville University • Millersville, PA • May 2013 • BA in Quantitative Economics, minor in Statistics
Curator for the Global Shapers Philadelphia Hub – World Economic Forum Initiative • September 2017-May 2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 7, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: */s/ Zachary F. Teti*
Zachary F. Teti

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

OCA STATEMENT 7- Supp.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
UGI Utilities, Inc. – Gas Division	**)**	**Docket No. R- 2025-3059523**
	)	
	)	

SUPPLEMENTAL DIRECT TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 21, 2026

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I. INTRODUCTION

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony updates the figures provided in my Direct Testimony, which was submitted on April 13, 2026, following my review of additional transcripts from public input hearings that have been published since that time. The concerns raised by residential customers and a government official during these subsequent hearings further underscore the affordability issues discussed in my Direct Testimony.

Q. DID THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC OR COMMISSION) CONDUCT PUBLIC INPUT HEARINGS FOR THIS PROCEEDING?

A. Yes, the Pennsylvania Public Utility Commission (PUC) conducted twelve Public Input Hearings to gather testimony from ratepayers and public officials to better understand the impact of the proposed rate increase.[1] Since the filing of my direct testimony on April 13, 2026, I am in receipt of additional transcripts that capture the testimonies of those who participated in the telephonic Public Input Hearings on April 10, 2026. This Supplemental Direct Testimony only addresses the 1 p.m. and 6 p.m. telephonic public input hearings on April 10, 2026, and supplements my Direct Testimony served on April 13. 2026. At the twelve public input hearings, a total of 18 customers and 9 public officials testified. My testimony focuses on public input hearing testimony that may be pertinent to the OCA's overall recommendations set forth in the OCA's Direct Testimony filed on April 13, 2026.

[1] My direct testimony as filed on April 13, 2026 focuses on the first ten, attended public input hearings to date and for which transcripts have been made available. I will be supplementing my direct testimony on or about April 21, 2026 and upon receipt of further transcripts.

Q. IN REVIEW OF THE ADDITIONAL PEOPLE WHO TESTIFIED TELEPHONICALLY, DOES THE PUBLIC RECOMMEND THAT THE COMPANY'S PROPOSED RATE INCREASE BE APPROVED BY THE PUC?

No.

Q. WHO TESTIFIED ON APRIL 10, 2026?

A. Witness Sickler of Dallas, Pennsylvania.

Q. WHAT KEY INSIGHTS DOES THIS WITNESS' TESTIMONY PROVIDE?

A. Witness Sickler describes a household of two retired women living on fixed incomes who already take deliberate steps to limit energy costs, such as keeping their home at 62°F in winter and carefully managing shared expenses. Despite these efforts, they report that repeated rate increases have made it increasingly difficult to maintain a manageable budget. This witness' testimony emphasizes that even with frugal habits, rising utility costs creates financial strain, and she believes that others in their community may be in even more vulnerable situations. (Transcript P. 353-354)

Q. WHAT DOES THIS TESTIMONY DEMONSTRATE ABOUT THE REAL-WORLD IMPACT OF CURRENT RATES AND THE POTENTIAL EFFECT OF ADDITIONAL RATE INCREASES ON CUSTOMERS?

A. This testimony demonstrates that financial pressure in UGI Gas' service territory is not hypothetical, as it is already affecting real customers who are actively conserving energy and still struggling. It shows that additional rate increases would not simply encourage efficiency but would, instead, burden customers who have little remaining flexibility to reduce usage or absorb higher costs. The fact that retirees on fixed incomes are already limiting basic comfort, such as heating, underscores the risk that further increases could force households to make even more difficult tradeoffs.

II. AFFORDABILITY: CUSTOMERS ARE STRUGGLING TO PAY THEIR BILLS

Q. PLEASE PROVIDE AN UPDATED COUNT OF THE NUMBER OF PEOPLE FROM THE PUBLIC WHO TESTIFIED ON THE TOPIC OF AFFORDABILITY.

A. Among the twenty-seven people from the public who testified, affordability concerns were raised twenty-four times. The ability to afford utility bills is a problematic issue raised by three out of five people who spoke in Lancaster, eleven out of twelve people who spoke in Wilkes-Barre, each of the two people who spoke in Reading, and each of the eight people who testified telephonically. In my opinion, UGI's customers and public officials are clearly opposed to any rate increases at this time.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION BASED ON THE EVIDENCE PRESENTED?

A. I respectfully urge the Commission to refrain from approving higher rates. The record demonstrates that current rates are already pushing some customers to the edge of affordability, and that additional increases would disproportionately harm those least able to pay, without providing meaningful opportunities for cost mitigation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Supplemental Direct Testimony, OCA Statement No. 7-Supp, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 21, 2026

Signature: */s/ Zachary F. Teti*
Zachary F. Teti

Address: Office of Consumer Advocate
555 Walnut Street
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. - Gas Division	:	
	:	

OCA AMENDED HEARING EXHIBIT 1

LIST OF EVIDENCE TO BE MOVED INTO THE EVIDENTIARY RECORD BY THE OFFICE OF CONSUMER ADVOCATE

The Office of Consumer Advocate (OCA) intends to submit the following evidence into the evidentiary record in the above captioned proceedings at the scheduled evidentiary hearings in this proceeding.

DIRECT TESTIMONY

OCA Statement No. 1: Direct Testimony of Michael Deupree consisting of written testimony with signed verification of Michael Deupree, Senior Research Consultant, Acadian Consulting Group, and the following:

- Appendix A
- Exhibit MWD-1 through Exhibit MWD-8

OCA Statement No. 2: Direct Testimony of Jennifer L. Rogers consisting of written testimony with signed verification of Jennifer L. Rogers, Principal and Vice President, Exeter Associates, Inc., and the following:

- Appendix A
- Schedule JLR – 2, JLR – 4 through JLR – 6, JLR – 8, JLR – 10 through JLR – 17, JLR – 19, JLR – 21 through Schedule JLR – 23

CONFIDENTIAL
OCA Statement No. 2: CONFIDENTIAL Direct Testimony of Jennifer L. Rogers consisting of written testimony with signed verification of Jennifer L. Rogers, Principal and Vice President, Exeter Associates, Inc., and the following:

- Appendix A

- Schedule JLR – 1 through Schedule JLR – 23

OCA Statement No. 3: Direct Testimony of David J. Garrett consisting of written testimony with signed verification of David J. Garrett, Managing Member, Resolve Utility Consulting PLLC, and the following:

- Exhibit DJG-1 through Exhibit DJG-16
- Appendix A through Appendix B

OCA Statement No. 4: Direct Testimony of James S. Garren consisting of written testimony with signed verification of James S. Garren, Senior Manager, NewGen Strategies and Solutions LLC, and the following:

- Exhibit JSG-1 through Exhibit JSG-3

OCA Statement No. 5: Direct Testimony of Barbara R. Alexander consisting of written testimony with signed verification of Barbara Alexander, Sole Member, Barbara Alexander Consulting, LLC, and the following:

- Exhibit BA-1 through BA-2, Exhibit BA-4 through BA-7

CONFIDENTIAL
OCA Statement No. 5: CONFIDENTIAL Direct Testimony of Barbara R. Alexander consisting of written testimony with signed verification of Barbara Alexander, Sole Member, Barbara Alexander Consulting, LLC, and the following:

- Exhibit BA-1 through Exhibit BA-7

OCA Statement No. 6: CORRECTED Direct Testimony of Roger Colton consisting of written testimony with signed verification of Roger Colton, Owner, Fisher Sheehan & Colton, and the following:

- Appendix A
- Exhibit RDC-1 through Exhibit RDC-4

OCA Statement No. 7: Direct Testimony of Zachary Teti consisting of written testimony with signed verification of Zachary Teti, Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate, and the following:

- Exhibit ZT-1

SUPPLEMENTAL DIRECT TESTIMONY

OCA Statement No. 7-Supp: Supplemental Direct Testimony of Zachary Teti consisting of written testimony with signed verification of Zachary Teti, Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate.

SURREBUTTAL TESTIMONY

OCA Statement No. 1SR: Surrebuttal Testimony of Michael Deupree consisting of written testimony with signed verification of Michael Deupree, Senior Research Consultant, Acadian Consulting Group, and the following:

- Exhibits MWD-9 through MWD-10

OCA Statement No. 2SR: Surrebuttal Testimony of Jennifer L. Rogers consisting of written testimony with signed verification of Jennifer L. Rogers, Principal and Vice President, Exeter Associates, Inc., and the following:

- Appendix A
- Surrebuttal Schedule Schedule JLR – 2, JLR – 4 through JLR – 6, JLR – 8 through JLR – 17, JLR – 19, JLR – 21 through Schedule JLR – 23

CONFIDENTIAL
OCA Statement No. 2SR: CONFIDENTIAL Surrebuttal Testimony of Jennifer L. Rogers consisting of written testimony with signed verification of Jennifer L. Rogers, Principal and Vice President, Exeter Associates, Inc., and the following:

- Surrebuttal Schedule JLR-1 through Schedule JLR-23

OCA Statement No. 3SR: Surrebuttal Testimony of David J. Garrett consisting of written testimony with signed verification of David J. Garrett, Managing Member, Resolve Utility Consulting PLLC.

OCA Statement No. 4SR: Surrebuttal Testimony of James S. Garren consisting of written testimony with signed verification of James S. Garren, Senior Manager, NewGen Strategies and Solutions LLC.

OCA Statement No. 5SR: Surrebuttal Testimony of Barbara R. Alexander consisting of written testimony with signed verification of Barbara Alexander, Sole Member, Barbara Alexander Consulting, LLC, and the following:

- Exhibit BA-8 through Exhibit BA-9

OCA Statement No. 6SR: Surrebuttal Testimony of Roger Colton consisting of written testimony with signed verification of Roger Colton, Owner, Fisher Sheehan & Colton.

ADDITIONAL EXHIBITS

OCA Hearing Exhibit 1: List of Evidence to be Moved into the Evidentiary Record by the Office of Consumer Advocate (OCA)

OCA Cross Exhibit 2: *In re Nova Scotia Power Inc. General Rate Application,* No. M12451, 2026 NSEB 8 (N.S. Energy Bd. Mar. 25, 2026).

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. UGI UTILITIES, INC. – GAS DIVISION	))))))))	Docket Nos. R-2025-3059523

OFFICE OF CONSUMER ADVOCATE

ERRATA TO OCA STATEMENT NO. 6

Errata to OCA Statement No. 6

p. 55, line 3: "customers from whom ~~PPL~~ UGI had previously received sufficient information to reasonably"

DECISION **2026 NSEB 8**
M12451

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF A GENERAL RATE APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for approval of certain revisions to its Rates, Charges and Regulations

BEFORE: Stephen T. McGrath, K.C., Chair
Roland A. Deveau, K.C., Vice Chair
Steven M. Murphy, MBA, P.Eng., Member

APPLICANT: **NOVA SCOTIA POWER INC.**
Blake Williams, Counsel
Jennifer Power, Counsel
Geoff Breen, Counsel
Colin Clarke, Counsel

INTERVENORS: **CONSUMER ADVOCATE**
David J. Roberts, Counsel
Michael Murphy, Counsel

SMALL BUSINESS ADVOCATE
Melissa P. MacAdam, Counsel
Rebekah Powell, Counsel

AFFORDABLE ENERGY COALITION
Peter Duke, Counsel
Chris Benjamin

EASTWARD ENERGY INC.
Allison Coffin
Angela Costello

EFFICIENCY ONE
James R. Gogan, Counsel
Lucia Westin-Eastaugh

INDUSTRIAL GROUP
Nancy G. Rubin, K.C.
Brianne Rudderham, Counsel

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA
James MacDuff, Counsel

NATURAL FORCES
Austen Hughes
Meg Morris

NOVA SCOTIA DEPARTMENT OF ENERGY
Daniel Boyle, Counsel
Girish Patel

NOVA SCOTIA INDEPENDENT ENERGY SYSTEM OPERATOR
Jason T. Cooke, K.C
Danielle J. Keating

NOVA SCOTIA LIBERAL CAUCUS
Chris Abraham
Iain Rankin

NOVA SCOTIA NDP CAUCUS
Claudia Chender
Susan Leblanc

PORT HAWKESBURY PAPER LP
David MacDougall, Counsel
James MacDuff, Counsel
Melanie Gillis, Counsel

RENEWALL ENERGY INC.
Daniel Roscoe

SWEB DEVELOPMENT
Mason Baker

BOARD COUNSEL: William L. Mahody, K.C.

HEARING DATE(S): January 7-13, 2026

FINAL SUBMISSIONS: February 6, 2026

DECISION DATE: **March 25, 2026**

DECISION: **The application is approved as amended by the Board. The revised rates will be confirmed in a compliance filing.**

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GLOSSARY OF ABBREVIATIONS

AA	Actual Adjustment
ACE	Annual Capital Expenditure
ADC	Active Demand Control
AEC	Affordable Energy Coalition
ALG	Average Group Life
AMI	Advanced Metering Infrastructure
ATL	Above-the-Line
AUC	Alberta Utilities Commission
BA	Balance Adjustment
BA_1	Annual Volume Variance Adjustment
BA_2	End of Approved DSM Term Adjustment
BTL	Below-the-Line
CAPM	Capital Asset Pricing Model
CBAS	Capacity-based Ancillary Services
COSS	Cost-of-Service Study
CT	Combustion Turbine
DCRR	Demand Side Management Cost Recovery Rider
DCF	Discounted Cash Flow
DDA	Decarbonization Deferral Account
DDM	Dividend Discount Model
DSM	Demand Side Management
E1	EfficiencyOne
EAA	Energy Access Agreement
EIFEL	Excessive Interest and Financing Expenses Limitation
ELG	Equal Group Life
ELIADC	Extra Large Industrial Active Demand Control
ELID	Extra Large Industrial Dispatchable
FAM	Fuel Adjustment Mechanism
FERC	United States Federal Energy Regulatory Commission
FFO:Debt	Funds from Operations to Debt
FLG	Federal Loan Guarantee
FTE	Full-time Equivalent Employees
GDP	Gross Domestic Product
GRA	General Rate Application
HAS	Hydro Asset Study
IESO Nova Scotia	Independent Energy System Operator Nova Scotia
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRs	Information Requests
IT	Information Technology
KMKNO	Kwilmu’kw Maw-klusuaqn Negotiation Office
LIIR	Large Industrial Interruptible Rider

MEUs	Municipal Electric Utilities of Nova Scotia
NARUC	National Association of Regulatory Utility Commissioners
NBV	Net Book Value
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NRR	Department of Natural Resources and Renewables
NSPML	Nova Scotia Power Maritime Link
NSUARB	Nova Scotia Utility and Review Board
OATT	Open Access Transmission Tariff
OM&G	Operating, Maintenance and General
OT	Operational Technology
PDF	Portable Document Format
PHP	Port Hawkesbury Paper
POA	Plan of Administration
PUA	Public Utilities Act
REI	Renewall Energy Inc.
RES	Renewable Electricity Standards
SCRR	Storm Cost Recovery Rider
S&P	Standard & Poors
TVP	Time-varying Pricing
UAD	Utility Asset Disposition
WACC	Weighted Average Cost of Capital

1.0 SUMMARY

[1] The Nova Scotia Energy Board is keenly aware that electricity rates are already challenging for many customers, and any rate increase will be difficult, especially for those with low or fixed incomes. However, the Board does not have the authority to provide special rates for these customers and, as noted by the Nova Scotia Court of Appeal, the Board's regulatory power under the *Public Utilities Act* is not an instrument of social policy.

[2] The *Public Utilities Act* entitles a utility the opportunity to recover its prudently incurred costs in providing a service to the public and an opportunity to earn a reasonable profit. While the Board can disallow costs found to be imprudent or unreasonable, absent such a finding, a utility's costs must be reflected in the rates paid by customers. The Board does not have the legal authority to disallow the recovery of legitimate costs to make rates more affordable.

[3] On September 18, 2025, NS Power filed a general rate application (GRA) with the Energy Board to change its rates for 2026 and 2027. The company proposed average rate increases across all customer classes effective on each of January 1, 2026, and January 1, 2027 (1.8% in 2026 and 2.4% in 2027). However, proposed rate increases vary across different customer classes, with residential customer rates proposed to increase 3.8% and 4.1% in 2026 and 2027, respectively. Some of the general and industrial customer classes will have more modest increases or even reductions in the proposed rates.

[4] NS Power previously advised the Board that the application was the "result of an extensive collaborative process involving NS Power and customer representatives

and it is being filed with the support of those representatives for the outcomes of the GRA". NS Power filed the settlement agreement on November 5, 2025.

[5] NS Power proposes changes to both its fuel and non-fuel costs. The rate increases are to cover the costs of providing service to its customers, including the generation, transmission and distribution of electricity as well as providing other services to its customers such as connection requests and customer service. NS Power outlined in its application that it is operating in complex circumstances. Indeed, NS Power is immersed in a multifaceted energy transition. The challenges include retiring its coal plants by 2030; providing 80% of its electricity from renewable resources on the same timeline; handling the worsening impact of climate conditions; and applying new technologies both on its grid and in providing innovative rates and service solutions to its customers.

[6] While the settlement agreement with the utility's customer representatives meant that these intervenors did not present evidence in the hearing to oppose the application, Board Counsel did engage various expert consultants to review the application. These included the proposed operating, maintenance and general (OM&G) costs, fuel costs, the cost of capital (including return on equity), depreciation, cost-of-service and other rate design issues. Additionally, intervenors, Board staff and Board Counsel consultants asked hundreds of information requests and received thousands of pages of additional information from NS Power about the application. The Board held its public hearing from January 7 to 9, 12 and 13, 2026. Written closing submissions were completed on February 6, 2026. The Board also received many letters of comment from customers.

[7] The general rate application contemplated securitization as an important new element, which NS Power described as the “centerpiece” of its application. The utility said it wishes to securitize about $704 million of its coal plants and thermal-related assets. Securitization is a complex commercial transaction that has the effect of reducing financing costs, thereby mitigating rate increases for customers. If securitization had occurred by January 1, 2026, as originally intended by NS Power, the utility estimated that costs would be reduced for customers by about $90 million over 2026 and 2027. Given that the securitization did not occur by year-end 2025, NS Power requested a “securitization deferral”. It asked that this regulatory account be used to defer financing costs and depreciation expense from January 1, 2026, onwards, related to the $704 million in coal-related assets it intends to retire. The amount collected in the deferral is proposed to be added to the total securitized amount.

[8] Morrison Park Advisors, a consultant firm engaged by Board Counsel to review the credit rating elements of the rate application, noted that NS Power had suffered a credit rating downgrade in November 2022 to BBB-, which is the lowest investment grade status and just one level above “junk bond” status. Morrison Park cautioned that the Board needs to be mindful of the risk of the utility dropping to “junk bond” status. It said a further downgrade would have “potentially significant consequences”, noting the importance of NS Power maintaining a minimum target of 10% funds from operations to debt (FFO:Debt), that being a key credit metric monitored by credit rating agencies. It concluded that if both the securitization proceeds and the proposed rate increases in this application are approved, the utility’s credit metrics should improve from their current precarious levels. Any delay in completing the securitization, or a partial approval of the

proposed rate increases, or both, would further limit the utility's ability to meet the credit metrics required by the rating agencies. However, Morrison Park stated that absent both the rate increases and the securitization, there was a likelihood that NS Power's credit rating could be downgraded even further. This would result in higher financing costs, which could amount to at least $25 million more each year in borrowing costs that would have to be included in customer rates.

[9] Securitization requires legislative action by the Province to allow it to proceed, something the Province has indicated it is not prepared to do, at least at this time. While it enacted a provision allowing securitization in the *Public Utilities Act*, the section is not yet in force and regulations still need to be developed. The Province's primary concern is that the coal plant assets proposed to be securitized are overvalued because insufficient depreciation was taken on the assets in the past and NS Power continued to invest in these assets despite nearer term retirement obligations. Settlement agreements in past rate applications in 2011 and 2014, kept depreciation rates lower than NS Power proposed. As a result, the value of the coal plant assets on which NS Power was able to earn a return was higher than it otherwise would have been if higher depreciation expenses had been applied.

[10] However, as canvassed in this decision, the settlement agreements in prior general rate applications had the effect of mitigating the rate impacts for customers at the time by avoiding accelerated depreciation on coal assets to be retired. Further, utility investors provide the upfront capital required to purchase or construct utility infrastructure to serve customers, and customers who use that infrastructure repay those costs over time as they receive the benefits of service. To attract and retain this investment, investors

are given the opportunity to earn a fair return on the capital invested, as well as ultimately recoup the amounts invested. The rate base value (including the value of the coal plant assets) presented in this general rate application follows generally accepted regulatory practice and the default method explicitly referenced in the *Public Utilities Act*. As described by the Supreme Court of Canada, a fair return means “the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise”. A low return on rate base may discourage investment in the utility. It may also lead to a poor credit rating, which would cause debt markets to increase the rate of interest on funds used by the utility to provide service. This may result in the utility’s rates increasing just to cover additional borrowing costs. It may even cause it to be excluded from participating in some debt markets altogether. Morrison Park reiterated these concerns in the present matter.

[11] NS Power and representatives of most of its customer classes presented a settlement agreement in this matter. The Nova Scotia Utility and Review Board (NSUARB) has considered settlement agreements in past matters, stating that the Board’s ultimate duty under the *Public Utilities Act* is to ensure that the terms of such an agreement are just, reasonable and in the public interest. As part of this exercise, the Board must ensure that "only those costs which are fair, justifiable and prudently incurred" by the utility are ultimately approved. There is no doubt that a settlement agreement concluded between the utility and most of its customer classes should attract significant weight.

[12] However, the circumstances leading to the settlement agreement in the present matter are different than in prior applications in that the parties negotiated the settlement agreement before the application was filed, rather than after a full evidentiary record was presented to the Board, including an independent review by various Board Counsel consultants about different components of the application. This is a factor that affects the weight the Board assigns to the settlement agreement. While the agreement is still entitled to some deference, this does change the Board's perspective on the settlement. It does not have the full benefit of the parties' views of the application, and the value assigned to various compromises reached in achieving a negotiated settlement. In some instances, the Board was left uncertain about whether certain perspectives had been analyzed or considered.

[13] Following its review of the evidence, the submissions and the law, while the settlement agreement does contain many terms that are appropriate and should be adopted, the Board concludes that some amendments to the application are required to ensure just and reasonable rates. The Board finds that the amendments to the application outlined in the remainder of this decision are appropriate and are necessary in the public interest.

[14] The Board finds that securitization could prove beneficial for customers by potentially reducing financing costs on the securitized amount, compared to reflecting the assets on the company’s balance sheet. Whether securitization ultimately proceeds is a policy matter for the Province to decide. In the interim, the Board approves the securitization deferral to address costs that NS Power removed from rates in this application because it expected securitization to proceed. In terms of the Province’s

concerns about the value of coal plant assets to be securitized, the Board finds that the past settlements noted by the Province in 2011 and 2014 were made at the time to lower customer rates. Further, under the *Public Utilities Act*, and consistent with generally accepted utility ratemaking principles across North America, the utility is entitled to recover its prudently incurred costs along with a reasonable return on and of its invested capital. To find otherwise could have significant negative financial implications for NS Power in the form of increased costs, leading to higher rates for its customers.

[15] NS Power's proposed return on equity was also an issue raised at the hearing. There was extensive expert evidence on this issue from two sources. Concentric Energy Advisors, NS Power's expert, recommended an average return on equity of 9.4% from its models (Undertaking U-14), while the same models applied by Dr. Sean Cleary, the Board Counsel's consultant, yielded an average recommended return on equity of 7.6%. Each of their models, inputs and assumptions had strengths and weaknesses. The Board finds that neither of the experts' recommended averages meet the "fair return standard", described above, with Dr. Cleary's recommendation being too low and Concentric's being too high. The appropriate return on equity is somewhere in between the two. In its application, NS Power asked to maintain its current return on equity of 9.0% for ratemaking purposes, with an earnings band of 8.75% to 9.25%. This request was supported by the customer classes in the settlement agreement.

[16] Dr. Cleary acknowledged in a recent proceeding before the Board that if the return was set at 7.6%, it would be the lowest recommended return on equity for a utility in Canada. Setting a return on equity at 7.6% would materially reduce NS Power's funds from operations and make its 10% FFO:Debt target more difficult to achieve. NS Power's

current credit rating from Standard & Poors (S&P) already places it in the bottom 10% of utilities in North America. A reduction in the return on equity below that proposed in the application would aggravate the situation. In the circumstances, the Board finds it would not be in the public interest to approve a return on equity that does not meet the fair return standard and deviates materially from the range of equity returns authorized for similar utilities across Canada. It finds that the current return on equity and capital structure should be maintained.

[17] Accordingly, the Board finds that most components of the settlement agreement appropriately resolve issues raised in the application. As a result, subject to its findings below that amend the application, the Board approves the following:

- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes remains at 40.0%;

- The establishment of the securitization deferral to defer depreciation expenses and financing costs related to the coal plants and thermal-related assets within the scope of the Decarbonization Deferral Account, but only effective from the date the rate increases in this application are implemented;

- NS Power's proposed depreciation rates;

- The proposed cost-of-service methodology and cost allocation among the various customer classes, except that NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs and to address other cost-of-service issues as noted in this decision;

- The PHP Deferral account, based on the assumptions in the settlement agreement, to track any variances in revenue between that which would occur based on the assumptions in the cost-of-service study treating PHP as an Above-the-Line customer versus that which results from the eventual Board-approved tariff for PHP. NS Power estimated $18.2 million would accrue in the deferral if PHP remains as a Below-the-Line customer for the entirety of 2026 (Undertaking U-2), and there would also be a $5.7 million fuel balance captured under the FAM;

- The EIFEL deferral, allowing NS Power to defer incremental tax expense of about $7 million if an exemption is not enacted by the Government of Canada as it has announced;

- The inclusion of four Maritime Link transmission capital projects in rate base. The amount to be included in rate base is the net book value of these assets as of the date of the Board's Order;

- Continuing the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis, which allows for underspent Level 3 and 4 costs to be returned to customers;

- The change to the tariff language for the Demand Side Management Cost Recovery Rider;

- Revising the Open Access Transmission Tariff (OATT) rates to reflect changes in the generation and transmission asset mix and costs, changes in system usage since the last update in the 2023-2024 GRA, Board directives from the 2023-2024 GRA, and the revised methodology from the 2024 Cost of Service proceeding; and

- Other miscellaneous fee changes under the Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees.

[18] While the Board is satisfied that many of the elements of the settlement agreement can be accepted, it has made several adjustments in this decision to reduce NS Power’s proposed revenue requirement or adjust the allocation of costs among customer classes, including:

- A further reduction of $8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the $9 million outlined in the settlement agreement);
- A reduction in NS Power’s proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power’s proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of $1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;

- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and
- The denial of the proposed AMI opt-out fee.

[19] Other issues were raised in this application which could also have impacted the proposed rate increases. These issues included considering a different depreciation treatment for the utility's assets and applying different cost-of-service procedures for the allocation of costs among the various customer classes.

[20] Under a cost-of-service model, the objective is to fairly allocate costs to customers based on cost causation. A change in the cost-of-service methodology for classifying distribution system costs (using the basic customer method) would have reallocated costs from domestic, small general and unmetered customer classes to other rate classes (Undertaking U-5). This change alone would have reduced the proposed rate increases for domestic customers from 3.8% and 4.1% in 2026 and 2027, respectively, to 2.2% and 2.8%. Larger reductions would have occurred for the small general class. However, this would have resulted in opposite rate impacts on other customer classes.

[21] It would be inappropriate to direct the use of the basic customer method simply to reduce the rate increase for residential, small general and unmetered customers. It would be just as inappropriate not to do so because of the impact that would have on other customers (with or without rate rider impacts). However, the parties did not fully press this issue in this proceeding due to the settlement agreement and the Board requires more information to further assess the cost causation basis for adopting the basic customer method. These issues will be brought before the Board for further consideration in a cost-of-service proceeding later this year.

[22] Similar considerations apply to the potential implementation of depreciation related issues. Assuming securitization were to proceed, the Board received evidence that a change from the Equal Life Group (ELG) to Average Life Group (ALG) depreciation methodology would have reduced NS Power's revenue requirement in each of 2026 and 2027, thereby reducing rates for all classes. Further, the Board considers such a change may be a more appropriate reflection of depreciation over the service lives of the company's assets. However, given the failure of securitization to occur by year-end 2025, the Board is not inclined to apply these changes because of the continued risk of a credit downgrade. A change in NS Power's depreciation expense from what is proposed in the application would negatively affect its FFO:Debt credit metrics and risk a credit downgrade. As Morrison Park noted, a further credit downgrade would have serious long-term cost consequences resulting in higher costs for ratepayers.

[23] The Board has also issued several directives to NS Power, summarized as follows, and set out in more detail at the end of this decision:

- To file an updated depreciation study with its next general rate application, with several directives to address a comparison of the ALG and ELG methodologies, and certain specified asset service life accounts;
- To report the results of its consultation process with interested parties about the decommissioning of hydro plants, no later than October 1, 2026, and every six months thereafter;
- To address the additional cost-of-service concerns raised by Synapse in its application to the Board later this year, in addition to the review of the minimum system v. basic customer method for allocating distribution system costs;

- To address the issues raised by Renewall in its closing submissions, if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator;
- To address the setting of customer charges in its next general rate application;
- To file a revised Climate Change Adaptation Plan by October 1, 2026, outlining climate related impacts on the utility's resources, activities and assets; actions to address the issues identified; potential and likely adaptation measures; and any challenges to mitigating risks; and
- Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used.

[24] The Board is satisfied that its findings in this decision result in just and reasonable rates for NS Power and that where it has departed from the terms of the settlement agreement it was in the public interest to do so. With the approval of the application, as amended, the Board concludes that NS Power will have a fair opportunity to recover its prudently incurred costs for the service it provides to its customers and to earn a fair return that allows it to attract new capital investment and maintain the financial integrity of the utility. Based on the evidence in this matter, this should also support the

company's credit metrics above target levels and avoid the negative consequences from a credit downgrade, which would impose further costs on NS Power and its customers.

2.0 BOARD'S AUTHORITY UNDER THE *PUBLIC UTILITIES ACT*

[25] The Board is an administrative body, established under the *Energy and Regulatory Boards Act*, SNS 2024, c 2, Schedule A. It must follow legislative requirements and administrative law principles. The Board's decisions may be appealed to the Nova Scotia Court of Appeal on any question of law or its jurisdiction. The Supreme Court of Nova Scotia may also judicially review aspects of its decisions.

[26] The Board is what has sometimes been referred to as a "creature of statute". In *Administrative Law in Canada*, 7th ed, p. 137 (LexisNexis Canada, 2022), Sara Blake described the powers of such entities:

> An administrative tribunal is created by statute and has only those powers conferred on it by statute. It has no inherent power to undertake proceedings or to make an order that affects a person's substantive rights or obligations. Most Interpretation Acts confer on tribunals all powers that are necessary to enable them to make the decisions and do the things they are expressly empowered to do. The powers that exist by necessary implication may be deduced from the wording of the Act, its structure, and its purpose. A tribunal's powers should be interpreted so as to enable the tribunal to fulfil the purposes of the statute rather than sterilized by overly technical interpretation, but statutory powers may not be expanded to accomplish what the tribunal thinks it ought to do to further its mandate in the public interest. If a tribunal has broad authority to make any order to remedy a violation of the Act, the remedy must be related to the violation, its consequences and the purposes of the Act.

[27] The NSUARB summarized the application of these principles in *Re Nova Scotia Power Incorporated* [2018 NSUARB 45]:

> [47] The UARB is a creature of statute and can only obtain jurisdiction from two sources: one, express grant of jurisdiction under the *PUA* and under other statutes (express powers); and two, from common law by application of the doctrine of jurisdiction by necessary implication (implicit powers).
>
> [48] In *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] SCC 4, the majority decision stated, at paragraph 51, that:

> …the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature.

[49] The majority also held, at paragraph 74 of the *ATCO Gas* decision, that:

> …the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework.

[28] The Board's general functions, power, duties and jurisdiction are expressly addressed in the *Energy and Regulatory Boards Act*:

> **Powers and duties**
> **5 (1)** The Energy Board has those functions, powers and duties that are conferred or imposed upon it
>
> (a) by this Act;
>
> (b) by the *More Access to Energy Act*;
>
> (c) respecting the production, transmission, delivery or furnishing of electrical energy for the purpose of heat, light and power or steam heat, geothermal heat, geothermal resources and electricity efficiency and conservation, by the *Public Utilities Act*;
>
> (d) by the *Gas Distribution Act*, the *Electricity Act*, the *Petroleum Products Pricing Act* or any other enactment; and
>
> (e) as the Governor in Council prescribes by the regulations.
>
> **(2)** The Governor in Council may assign to the Energy Board the powers, functions and duties of any board, commission or agency and while the assignment is in effect, that board, commission or agency is discontinued and Section 43 applies with necessary changes respecting that board, commission or agency.
>
> **Approving and fixing rates, regulatory powers**
> **6 (1)** In approving or fixing just and reasonable rates, tolls, charges or tariffs pursuant to this Act or any other enactment, the Energy Board may adopt any method or technique that it considers appropriate, including an alternative form of regulation.
>
> **(2)** In approving or fixing rates, tolls, charges, tariffs, capital applications and all other matters over which the Energy Board has authority, the Board shall give appropriate consideration to the extent to which such rates, tolls, charges, tariffs, capital applications or other matters
>
> (a) support competition and innovation in the provision of energy resources in the Province;

(b) support the development of a competitive electricity market;

(c) ensure the provision of safe, secure, reliable and economical energy supply in the Province;

(d) support sustainable development and sustainable prosperity; and

(e) support such other factors as prescribed by the regulations,

with the goal of approving rates, tolls, charges, tariffs, capital applications or other matters that are consistent with the purpose of this Act, the *More Access to Energy Act* and the regulations.

(3) Subject to subsection (4), the Energy Board shall regulate

(a) the Independent Energy Systems Operator, transmitters and all matters relating to public utilities that perform the functions of production, transmission, delivery or furnishing of electrical energy to or for the public for the purpose of heat, light and power, geothermal resources, geothermal energy, geothermal heat or steam heat;

(b) the franchise holder granted a franchise pursuant to Section 79C of the *Public Utilities Act*;

(c) the Halifax Water district energy project;

(d) any holder of the franchise to construct and operate a gas delivery system in the Province pursuant to the *Gas Distribution Act*; and

(e) any other entity or service prescribed by the regulations.

(4) The Governor in Council may make regulations

(a) prescribing factors for the Energy Board to consider when approving rates, tolls, charges or tariffs, capital applications and all other matters over which the Energy Board has authority respecting the production, transmission, delivery or furnishing of electrical energy for the purpose of heat, light and power or steam heat, including combined heat and power;

(b) excluding any entity or service from the jurisdiction of the Energy Board.

(5) The exercise by the Governor in Council of the authority contained in subsection (4) is a regulation within the meaning of the *Regulations Act*.

(6) The Energy Board shall endeavour to issue fair decisions in relation to all matters in a manner that is efficient, effective and as timely as possible.

> **(7)** The Energy Board shall make public all approved rates, tolls, charges, tariffs and capital applications on its website and update these documents as required.
>
> …
>
> **Jurisdiction of Board**
> **30 (1)** A Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on the Board.
>
> **(2)** The Boards, as to all matters within their jurisdiction pursuant to this Act, may hear and determine all questions of law and of fact.

[29] Public utilities tend to be natural monopolies. As such, the impact of competitive forces on those entities may be muted or non-existent. In the absence of these forces, the Board's ratemaking function is designed to allow the utility to recover its legitimate costs of providing service and an opportunity to earn a reasonable profit at rates that are fair for its customers. This ratemaking function has been described by the Nova Scotia Court of Appeal as a surrogate for competition and not a tool for implementing social policy:

> [32] The Board sets rates for a utility that has a virtual monopoly on the supply of electric power. The Board's decision discusses this process: (2005 NSUARB 27)
>
> > [17] … NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the utility is permitted, under the ***Act***, to recover the reasonable and prudent costs of providing the service. Because it is a monopoly, regulation operates as a surrogate for competition. <u>One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.</u>
> >
> > <u>[18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.</u>
> >
> > [19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly.

> [33] I agree with this portrayal of the background to the Board's rate-making function. The Board's regulatory power is a proxy for competition, not an instrument of social policy. [Emphasis added]
>
> [*Dalhousie Legal Aid Service v Nova Scotia Power Inc.*, 2006 NSCA 74]

[30] As noted already, the Board's powers are defined by legislation. Section 45 of the *Public Utilities Act,* RSNS 1989, c 380 (*PUA*) requires the Board to use a cost-of-service methodology to set rates and entitles the utility to a just and reasonable return:

> **Amount utility entitled to earn annually**
>
> **45 (1)** Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly.
>
> **(2)** Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[31] In legislation, the word "shall" is mandatory. However, the phrases "just and reasonable" and "reasonable and prudent" allow the Board to exercise some discretion. Additionally, the Board's mandate under the *PUA* encompasses a significant public interest component (*Nova Scotia (Attorney General) v Nova Scotia (Utility and Review Board*), 2019 NSCA 66, paras 113-116). But as considered above, the Board's implicit powers are tied to the purposes of the statute.

[32] The Nova Scotia Supreme Court, Appeal Division decision in *Nova Scotia (Public Utilities Board) v Nova Scotia Power Corporation*, (1976) 18 NSR (2d) 692 (the *Contracts Case*) is often referenced for its consideration of the scheme of regulation under the *PUA*:

17 The scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service. Two great objects are enshrined - that all rates charged must be just, reasonable and sufficient and not discriminatory or preferential, and that the service must be adequately, efficiently and reasonably supplied to the public. Almost all provisions of the Act are directed toward securing these two objects - that a public utility give adequate service and charge only reasonable and just rates.

18 The service requirement is expressed in s. 48, as follows:

> 48 Every public utility is required to furnish service and facilities reasonably safe and adequate and in all respects just and reasonable.

… 20 Rates must be "just" (s. 41) and must not be "unreasonable or unjustly discriminatory" (s. 18 and s. 78(1)), or "unjust, unreasonable, insufficient or unjustly discriminatory, or . . . preferential" (s. 82(1)). The "justness" of rates has two aspects - rates of a utility as a whole must be "reasonable" and just for the public it serves and just and "sufficient" for the utility itself - and the rates for the various customers or classes of customer of a utility must not as between each other be "unjustly discriminatory" or "preferential".

21 The control of the over-all level of rates has its keystone in s. 42(1) which states:

> 42 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board.

…

23 The concept of a utility securing a reasonable return on its rate base automatically makes specific the apparently vague standard that rates be "just". The utility's economic health and its ability to supply adequate service and to finance capital expansion are assured by giving it a "just and reasonable" return. Overall rates must thus be sufficient to produce that return after allowing operating expenses and other "just allowances" (s. 42(2)). The rates must thus be "sufficient" to produce that return, no less and no more.

24 The public interest charges the Board with the duty of ensuring no extravagance by a utility in either capital or operating expenditure. The rate base is to include only assets "used and useful" in providing service (s. 29 (1)). Additions to it are controlled by the requirement that Board approval be secured for any new construction project of more than $5,000 (s. 34 as amended). The expenses for rate-making purposes are only those the Board allows "as reasonable and prudent and properly chargeable to operating account" (s. 42(2)). Other "just allowances" are prescribed by the Act and Regulations, *e.g*. annual depreciation charges (ss. 35-38).

…

26 The Board has on occasion summarized its duty in terms which, accurately I believe, emphasize the comprehensive nature of its control of the rates and services of a utility. Its decision of February 25, 1970, in respect of an application of Maritime Telegraph and Telephone Company Limited, contains the following at p. 25 of the Board's Report for 1970:

> A public utility is obligated to provide services that are reasonably safe and adequate and is entitled to compensation therefor by the charging of rates

> that are not unjustly discriminatory and will provide the public utility with sufficient revenue to enable it to pay its operating expenses including depreciation and income taxes, and have net earnings sufficient to enable it to obtain and service normal and needed capital requirements. It is expected to meet reasonable demands for additional services and to conduct its affairs with efficiency. When an application is made to this Board for approval of revisions in rates, tolls and charges designed to produce additional revenue the public utility is required to produce evidence showing the needs and purposes for which such additional revenue is required. And upon any such application the Board inquires into and examines the adequacy and reasonableness of existing services, the efficiency of the public utility, the nature and extent of the needs and purposes upon which the application is grounded and the propriety of the proposed rate changes.
>
> 27 The "propriety" of the rates involves not only the propriety of their over-all level as adjudged by rate base return, but also their propriety for the various classes of customer. The Board's twofold duty is to ensure that the rates as a whole are reasonable and that they are reasonable to all customers *inter se*. This latter aspect of its duty is imposed by the various provisions prohibiting unjust discrimination and requiring equal rates in substantially similar circumstances. [Emphasis added]

[33] In exercising its ratemaking function, following the statutory requirements and mindful of the purposes of the legislation, the Board is also guided by the following long-established, fundamental ratemaking principles, which the NSUARB noted in its decision for NS Power's rate application in 2002 and a number of rate applications since:

> [21] In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> [22] A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.

> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
> (a) in the control of the total amounts of service supplied by the company;
> (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
> (Exhibit N-92) (James Bonbright, **Principles of Public Utility Rates**, Columbia University Press, 1961, p. 291)
>
> [23] These principles are well established and form the background against which the current application must be assessed.
>
> [2002 NSUARB 59, paras. 21-23]

[34] The principles of statutory interpretation apply in determining the intent of any particular statute, including in the Board's interpretation of the statutory provisions in the *Public Utilities Act*, and other legislation relevant to this matter, to determine the scope of the powers conferred upon the Board.

[35] As discussed in the reasons of the majority in the Supreme Court of Canada's decision in *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65, administrative decision makers are required to consider the text, context and purpose in interpreting legislation. The Board must also have regard to the *Interpretation Act*, RSNS 1989, c 235.

3.0 ANALYSIS AND FINDINGS

3.1 Should the Settlement Agreement be Approved?

[36] On September 2, 2025, NS Power wrote to the Board to advise that it would be filing a general rate application for the 2026 and 2027 test years. It stated that it had reached a consensus with the customer representatives which was the "result of an extensive collaborative process involving NS Power and customer representatives and it is being filed with the support of those representatives for the outcomes of the GRA".

However, it did not file its general rate application until September 18, 2025. NS Power only filed the settlement agreement on November 5, 2025, when asked to do so in information requests (IRs) by Board staff.

[37] The terms of the settlement agreement are set out in a schedule to the agreement and provide as follows:

GRA Element	Settlement Terms
Rates	a) Rates are proposed to be effective January 1, 2026 and the Parties will make all reasonable efforts to facilitate and support a process that will result in this outcome. b) Subject to the terms set out herein being fully incorporated into the 2026-2027 GRA, the average rate increase across all customer classes (inclusive of non-fuel and Base Cost of Fuel costs) is anticipated to be approximately 2.1% in 2026 and 2.1% in 2027.
Depreciation	a) The Parties agree to reduce depreciation rates in accordance with Appendix "A" in order to achieve a reduction in depreciation and accretion expense of approximately $20M/year over the 2026-2027 test period, as compared to the depreciation rates included in the Draft GRA.
O&M	a) The Parties agree to the operation and maintenance expense amounts included in the Draft GRA, subject to the reductions in O&M set out in the attached Appendix "B".
Storm Cost Recovery Rider	a) The Storm Cost Recovery Rider will be implemented as described in the Draft GRA, subject to the following: (a) the Storm Cost Recovery Rider will not be implemented on a permanent basis as proposed, rather it will continue on a pilot basis with costs in 2026 and 2027 eligible for the rider; and (b) the threshold for making an application to return an

GRA Element	Settlement Terms
	underspend to customers will be changed from $5 million to $2.5 million.
Cost of Capital and Earnings Band	a) An overall return on equity of 9% for rate setting purposes retained, as well as an earnings band of 8.75% to 9.25%.
Capital Structure	a) An equity thickness of 40% for rate setting purposes will be retained.
DSM Rider	a) The DSM Rider will be amended as set out in Appendix "C". NS Power will make best efforts to negotiate necessary revisions to its Supply Agreement with EfficiencyOne, if any, or otherwise bring such revisions forward in the relevant proceeding to ensure that the End of Approved DSM Term Adjustment is implemented for the 2023-2026 term.
Weather Normalization Mechanism	a) The request for approval of a Weather Normalization Mechanism will be removed; however, the parties agree to participate in an information session to gain a better understanding of Weather Normalization Mechanisms.
Cost of Service ("COS")	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.
MEU Treatment	a) The MEUs will be included as taking service under the Municipal Tariff in calculating the Municipal Tariff rates for the 2026-2027 GRA and the MEUs commit to taking partial service under the Municipal Tariff in the years 2026 and 2027 .

GRA Element	Settlement Terms
	b) NS Power and the MEUs will work collaboratively and in good faith to determine and attempt to agree, by no later than December 1, 2025 on (1) the timeline by which the MEUs will pay NS Power the full amounts of outstanding fuel costs and Maritime Link Assessment costs, and (2) the implementation of the BUTU Tariff service arrangements in conjunction with service under the Municipal Tariff in 2025, 2026, and 2027.
OATT	a) In calculating the OATT rate, NS Power will cap the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service. b) The 2-standard deviation methodology will be used for ratemaking purposes for the load following requirement. c) For the 2026-2027 GRA period, the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis.
PHP Treatment	a) NS Power's 2026/2027 cost of service study includes PHP as an above-the-line customer based on the forecast of receiving Board approvals for a new PHP tariff in time to implement for January 1, 2026. b) The COS has been prepared on the basis of the following PHP load characteristics: a) PHP's firm load at 8MW at the three coincident peaks; b) PHP's firm, plus interruptible load, at a forecast of 65 MW based on prior actual PHP metered load at the time of NSP's 3CP; and c) PHP energy will be based on PHP's forecast usage for the test years, net of the amount forecast to be provided by the Goose Harbour Lake Wind Farm. The same load characteristics are applicable to the base cost of fuel model as well. c) The dollar value of the Interruptible credit to be applicable to PHP's interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit. d) PHP and NS Power will complete discussions and analysis of the value of Active Demand Control ("ADC"), which shall be proposed to be a rider to the cost-based rate. The value of ADC, and the proposal for cost recovery, if any, shall be

GRA Element	Settlement Terms
	brought forward for approval by the Board later this year to be effective January 1, 2026. For clarity, any payment approved by the Board for Active Demand Control services will be collected from above the line customers. e) NS Power and PHP shall reflect the foregoing in a written tariff which shall also include a proposal for priority interruptibility to be brought forward for approval by the Board later this year to be effective January 1, 2026 and PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes. f) In the PHP ADC and tariff processes that will be brought forward for approval by the Board later this year, it remains open for all Parties to take any position they so choose, including whether each of the PHP ADC and tariff filing(s) is inconsistent with the load characteristics and basic tariff structure as set out above. g) NS Power may seek Board approval for a deferral account to account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers: (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA; (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.
Securitization	a) NS Power will make best efforts to finalize and apply prior to January 1, 2026 for approval of its proposed securitization of assets, cost of service treatment and the Securitization Rider. It remains open for all Parties to take any position they so choose in relation to such an application.
ML Transmission Assets	a) Inclusion of CI 43324, CI 43678, CI 45066, and CI 45067 in rate base, subject to the Board being satisfied that the threshold test it articulated in paragraph 405 of its decision in M10431 has been met.

GRA Element	Settlement Terms
EIFEL	a) If the excessive interest and financing expenses limitation ("EIFEL") exemption is not enacted, the Parties agree to defer the incremental tax expense over the 2026-2027 GRA period, which is anticipated to be approximately $7.5 million.
NS Power Future Deliverables	a) Within a reasonable amount of time following the execution of this Settlement Agreement, NS Power will provide: (a) confirmation that radial to generation lines being allocated to the generation function do not also serve any load; and (b) the methodology that NS Power is proposing to functionalize storage assets.

[Exhibit N-27, NSEB IR-1, pp. 9-13]

[38] Previous decisions by the NSUARB set out the principles it applied in its consideration of settlement agreements. Those principles are still relevant and bear repeating. In its decision dated November 5, 2008, about a prior NS Power general rate application, the NSUARB outlined its general approach to settlement agreements submitted to it for approval:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.
>
> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.

> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [2008 NSUARB 140]

[39] The Board remains mindful that in its consideration of settlement agreements its ultimate duty is to ensure that the terms of the agreement are just, reasonable and in the public interest:

> [23] … Settlement agreements do not, however, diminish the Board's duty and obligation to ensure that the terms of any such agreement result in approval of only those costs which are fair, justifiable and prudently incurred by the Utility. Further, the Board must ensure that these costs result in customer rates that are just, reasonable and in the public interest. In addition, when deciding whether to approve a settlement agreement, the Board must be satisfied that the outstanding concerns of all intervenors are adequately considered by the Board and the terms and conditions under which they consent to a settlement agreement are honored.
>
> [*NS Power 2007 GRA* decision, 2007 NSUARB 8]

[40] The Board agrees with the following submission in the NSUARB's *2023-2024 GRA* Decision about the important role of settlement negotiations in such proceedings:

> … It is in the public interest to approve settlement agreements in these circumstances in order to encourage a collaborative approach to ratemaking. Doing so provides incentive to parties to be reasonable and promotes the reduction of controversy in rate applications coming to the Board.
>
> [Board Decision, M10431, para. 60]

3.1.1 Findings

[41] As noted above, the NSUARB has considered settlement agreements in past matters. The Board appreciates the efforts of parties to resolve contested issues in matters coming before it and encourages such initiatives to continue. Notwithstanding

that, the Board reiterates that its ultimate duty in considering settlement agreements is to ensure that the terms of such agreements are just, reasonable and in the public interest. As part of this exercise, the Board must ensure that “only those costs which are fair, justifiable and prudently incurred” by the utility are ultimately approved.

[42] There is no doubt that a settlement agreement between the utility and most of its customer classes should attract significant weight. The Board recognizes that significant efforts were called upon in canvassing the complex myriad of issues that were ultimately concluded in their settlement. The Board is mindful that the discussions and negotiations involved compromises by all parties in the final result. The customer representatives actively participate in numerous NS Power proceedings before the Board. The Board recognizes that by negotiating a settlement agreement, parties tried to reduce hearing costs and achieve some certainty over the results.

[43] However, there is a distinction between what occurred in prior general rate applications and what transpired in the current proceeding. Previously, settlement agreements were concluded after an extensive evidentiary record had been filed with the Board, including many information requests and evidence filed by intervenors (among them the very customers who signed a settlement agreement) and Board Counsel consultants. In the current matter, the settlement agreement was concluded even before the application was filed. While this does not negate the efforts of the parties to reach a settlement, the Board concludes that it is a factor that affects the weight it assigns to the settlement agreement. The agreement is still entitled to some deference but, given the circumstances, it does change the Board’s perspective on the settlement. It does not have the full benefit of the parties’ views of the application, and the value assigned to various

compromises reached in achieving a negotiated settlement. In some instances, the Board was left uncertain about whether certain perspectives had been analyzed or considered. Further, the Board does have the benefit of having the evidence of the Board Counsel consultants, who did not participate in the settlement discussions but were able to conduct an independent review of the application.

[44] A general rate application is a very complex proceeding which raises a multitude of difficult issues. The Board is left with the very difficult duty to ensure that the terms of the settlement agreement are just, reasonable and in the public interest. Following its review, the Board finds that the settlement agreement does contain many terms that are appropriate and should be adopted. However, the Board also concludes that some amendments to the application, as described in the remainder of this decision, are required to ensure just and reasonable rates.

3.2 Fuel and Purchased Power

[45] Fuel and purchased power expenditures are direct pass-through costs paid by NS Power's customers. Under the Fuel Adjustment Mechanism (FAM), those costs are identified as the Base Cost of Fuel (BCF). Actual fuel and purchased power costs will be tracked, but actual costs will differ from forecast costs. Any over or under recoveries will be refunded or collected through the FAM Actual Adjustment (AA) and Balance Adjustment (BA) riders. Throughout each year, NS Power provides monthly, quarterly and annual updates of its fuel costs and the recoveries from customers. In addition, an independent auditor appointed by the Board conducts fuel cost audits every two years and those audits are reviewed in public regulatory proceedings.

3.2.1 Base Cost of Fuel

[46] Fuel and purchased power costs comprise the largest portion of NS Power's revenue requirement. During the two-year test period, NS Power has forecast those costs to be $918.6 million for 2026 and $918.4 million for 2027. This represents about 47.4% and 46.1% of the annual revenue requirements, respectively.

[47] However, in this application NS Power is seeking approval of new BCF amounts of $927.3 million for 2026 and $850.9 million for 2027. With those BCF adjustments, NS Power proposes to smooth the overall increases (combined BCF and non-fuel rates) for each rate class during the 2026-2027 GRA period. This results in setting rates that over-collect fuel costs in 2026 but under-collect in 2027.

[48] Board Counsel engaged a consultant, Bates White, to review NS Power's fuel and purchased power costs, which included the BCF, load forecast report, the accuracy of NS Power's commodity price forecasts, and determining whether the NS Power application adequately represents the fuel component.

[49] As seen in Figure 5-2 below, based on the two-year BCF forecast, NS Power applied for an average annual increase in FAM customer rates of 2.3% in 2026 and a reduction of 1.7% in 2027. Bates White noted that in contrast with the 2023-2024 GRA, NS Power did not include any files supporting the AA/BA calculations. When asked in NSEB IR-36 about the anticipated rate impacts from the AA/BA, NS Power stated that it did not complete the rate impact analyses, but those details would be provided in the FAM AA/BA application anticipated to be filed prior to the end of 2025. The AA/BA amounts are subject to revision and finalization during a separate regulatory proceeding near the end of each year. On December 18, 2025, NS Power applied to the Board to extend the existing AA/BA riders on an interim basis, effective January 1, 2026, pending

a decision in this GRA and a subsequent AA/BA application which it intended to file in January 2026. The Board granted that request in Matter M12640 on December 23, 2025.

Figure 5-2 – 2026-2027 Fuel Rate Percentage Changes with Smoothing

Customer Class	2026	2027
Residential	1.2	(0.4)
Small General	2.7	(0.8)
General	3.5	(3.2)
Large General	3.8	(5.7)
Industrial		
Small	4.7	(3.3)
Medium	3.8	(6.7)
Large Industrial		
Firm Transmission Service	4.1	(6.6)
Firm Distribution Service	3.9	(6.3)
Interruptible Transmission Service	4.9	(8.0)
Interruptible Distribution Service	4.5	(7.5)
Large industrial Total	4.6	(7.6)
Municipal	9.6	(0.4)
Unmetered	(0.7)	2.8
Total	2.3	(1.7)

[Exhibit N-3, p. 28]

[50] In its response to Bates White IR-10, NS Power stated that it is forecasting a FAM liability of $10.2 million at the end of 2026 and $0.8 million at the end of 2027. NS Power also stated that at its weighted average cost of capital (WACC), the FAM deferral will incur interest expense of $1.0 million in 2026 and $1.3 million in 2027.

[51] In assessing whether NS Power has adequately represented the fuel and purchased power component in the application, Bates White noted that in some cases, NS Power was unable to provide all requested data due to a cybersecurity incident which made data retrieval impossible. However, Bates White stated that NS Power used

reasonable, publicly available forecasts of prices for fuels, including natural gas, coal, and heavy fuel oil, as well as purchased power.

[52] Although Bates White considered that the forecasts appeared reasonable, they noted those forecasts were dated. NS Power used PLEXOS, a commercially available hourly economic dispatch model, to forecast its fuel and purchased power consumption over the 2026-2027 period. In its evidence, Bates White stated:

> The original PLEXOS forecast was run in November 2024 using a 30-day average of prices as of October 29, 2024. In March 2025, following receipt of the Sulphur Dioxide ("SO_2") Certificate of Variance ("CoV"), the forecast was rerun. The results of the March 2025 run were used in the September 2025 filing.
>
> NSPI's decision to use the October 29, 2024 commodity price forecasts is likely reasonable, given that NSPI has reached settlement with several parties and that FAM costs are included in the Settlement Agreement. Using more updated commodity price forecasts would be optimal, given that more updated forecasts would represent the best and most updated expectations of fuel and purchased power prices in 2026 and 2027, but we acknowledge NSPI's point that updating rates could upset the Settlement Agreement. Still, using a more updated forecast could be warranted if there were major changes in the forecast of either energy [or] demand for the 2026 or 2027 period.
>
> … some commodity price movement has been observed since the time of the GRA commodity price forecasts (October 2024). Monthly coal futures for the 2026-2027 period, as measured by the API-2 index, are lower by an average of 2.8%. Monthly natural gas price futures, as measured at Henry Hub, are higher by an average of 12.4%.
>
> … Given the timing of the settlement discussions, NSPI's reliance on commodity price forecasts from October 29, 2024 appears reasonable, despite some moderate movement in commodity price forecasts. We observe no major changes regarding commodity futures prices that would require an update to the rates, which could potentially negatively impact the nature and status of the Settlement Agreement reached by the parties in this proceeding. [Emphasis added]
>
> [Exhibit N-35, pp. 14-15]

[53] In reviewing NS Power's load forecast, Bates White noted that the GRA forecast was an update to NS Power's 2024 Load Forecast, and the 2026 and 2027 GRA represented settlement agreement outcomes based on rates developed in 2024 and early 2025, before the 2025 Load Forecast Report was issued. Bates White also stated:

> NSPI's decision to use the September 2024 GRA Forecast is reasonable. The GRA Forecast uses the same methodology as the Board-approved 2024 Load Forecast and provides an interim update of energy demand and peak load in its settlement discussions with customer representatives. Using the 2025 Load Forecast data would be optimal, given that the 2025 Load Forecast represents the best and most updated expectations of energy

> [and] demand in 2026 and 2027, but we acknowledge NSPI's point that updating rates could upset the Settlement Agreement. Still, using a more updated forecast could be warranted if there were major changes in the forecast of either energy [or] demand for the 2026 or 2027 period.
>
> … The GRA Forecast expectations for energy demand in 2026 and 2027 is within 1% of the forecast values for both the 2024 and 2025 Load Forecasts.
>
> ... Given the timing of the settlement discussions, NSPI's reliance on the September 2024 GRA Forecast appears reasonable, and we observe no major changes between the 2024 and [*sic*] GRA Load Forecasts and the 2025 Load Forecast that would warrant an update to the rates, which could potentially negatively impact the nature and status of the Settlement Agreement reached by the parties in this proceeding. [Emphasis added]
>
> [Exhibit N-35, pp. 33-35]

[54] During the hearing, NS Power was asked about the amount included in its revenue requirement for the NSP Maritime Link Inc. (NSPML) assessment relating to the interest and principal for repayment of the $500 million Federal Loan Guarantee (FLG). NS Power included $41.5 million for 2026, but a subsequent NSPML application identified that cost to be $1.8 million lower at $39.7 million. The cost included in its 2027 revenue requirement may also be inflated by a similar amount:

> **Q.** So in this case, it refers to Appendix 5A and it says:
>
> On page 34 of Appendix 5A, the application states that NSPML's forecast assessments for the Maritime Link against Nova Scotia Power are $200.5 million in 2026 and $203.9 million in 2027 (including $41.5 million and $40.6 million for ['26 and '27 to pay the] interest and principal on the... Federal Loan Guarantee.
>
> So in relation to the federal loan guarantee portion of it, I note -- and you can take it subject to check, hopefully -- that we currently have an assessment before the Board, the 2026 NSPML assessment, and instead of the 200.5 million assessment in '26, the actual request was 198.7, which is a difference of 1.8 million. And one of the major differences in that is that the amount included for the federal loan guarantee, instead of being 41.5 million, was actually 39.7. So it was actually almost a difference of 2 million there.
>
> And so -- and because that balance will be reducing -- well, the balance they had, 39.7 for 2026, is already lower than what you had projected for -- or what was in the Application for 2027. So it's 1.8 -- the actual assessment, if it's approved, will actually be -- and probably won't be higher than that. It might be lower. But the assessment would be at least 1.8 million less than what's in your base cost of fuel. And I suspect that the same would happen for 2027. So that's 2 million over two years.
>
> I'm just wondering whether the – I don't know -- I've gone through the '26 assessment. I haven't found a reference to what a projected '27 assessment would be, but I suspect it's pretty close. So that would be 2 million over two years.

Is there some way we could -- I could ask you for an undertaking if you could check with NSPML what their projection is for at least the federal loan guarantee part and we could take that difference. But that's $2 million right there off of both years on the base cost of fuel.

So I'm just -- do you have any comment or solution in terms of adjusting the base cost of fuel for those amounts?

And I suspect there's a schedule -- I just couldn't put my hand on it -- for the federal loan guarantee, but I know they're going down. You're paying less every year. So I suspect it's probably low 39 to approximately high 38 million for '27.

A. (Willett) I can't speak to the 2027 latest projection. But what I would mention is these estimates were obviously taken at a point in time and to the best estimates at that time, just like any ---

Q. Oh, I agree.

A. (Willett) --- commodity or just like coal, the numbers will fluctuate, and the AA/BA process is there to true those up, so customers only pay the actual cost of the assessment and the FLG.

The other item, just to note as well, with rates not going into place January 1, those rates currently are set below cost so there will be or there is expected to be under-recoveries until those rates are in place to match the true cost. So those items will be trued up through the AA/BA, but we will be seeing under-recovery of -- until those rates are in place for the base cost of fuel.

Q. Right. Except that we know the 200.5 million is not a projection any more. It's actually -- for '26, it's only 198.7. So we know that number.

It's not a projection any more. We actually know it. Two million dollars, you know, is $2 million over two years would be -- you know, it's $4 million.

A. (Williams) Mr. Deveau, if I may -- and I agree. So in terms of the volatility discussion, volatility, uncertainty until you've -- you've got certainty, which with commodities very rarely do you ever get certainty until you've actually made the purchase, whereas with this there is certainty in terms of the price.

I think more to the point, though, is the $2 million difference that you're speaking to will not actually be $2 million because, as Mr. Willett was indicating, rates won't be in effect as of January 1, 2026. So you'll have that shortfall that will need to be made up in any event. So the $2 million is likely made up as a result of that regardless.

Q. Right. This is not a commodity, though. These are costs.

A. (Williams) No, agreed...

[Transcript, January 9, 2026, pp. 840-845]

[55] In its closing submissions, Renewall Energy Inc. (REI) raised a concern with the accuracy of NS Power's fuel forecasts. REI noted that average fuel cost forecasts in each of the past five years were significantly lower than actual costs, and that increased

accuracy is essential for encouraging competition in Nova Scotia, as well as to avoid interest on fuel cost deferrals. REI further stated:

> This means that NSPI's customer rates have been lower than required in each of the last 5 years. If NSPI's retail rates are consistency [*sic*] lower than needed to recover the appropriate revenue, it creates an unfair market condition for retail competition in two ways. It sets an unrealist benchmark of posted retail rates for comparison purposes, and it creates an ongoing fuel liability for customers looking to leave NSPI bundled service.
>
> …
>
> REI respectfully requests that the Board direct NSPI to establish more accurate fuel cost forecasts, and to follow the FAM POA that outlines that fuel cost overages from one year be recovered in the following year (rather than deferred over multiple years).…
>
> [REI Closing Submissions, p. 5]

[56] On pages 28-29 of its reply submissions, NS Power responded to REI's concern:

> NS Power submits that no such directive is warranted or necessary. The Plan of Administration (POA) outlines the approved process for forecasting of fuel and purchased power expenses. As the Board is aware, NS Power is audited bi-annually by the Board-appointed Fuel Adjustment Mechanism (FAM) Auditor, Bates White. The Auditor specifically evaluates and opines on the Company's adherence with the POA. Further, as noted in the Company's closing submission, Bates White submitted evidence in this proceeding on behalf of Board Counsel and indicated that NS Power used reasonable methods and resources in its forecast of fuel and purchased power costs included in this GRA.

3.2.1.1 Findings

[57] The Board notes that NS Power's proposed BCF was deemed acceptable to customer representatives who signed the settlement agreement. The Board also notes Bates White's statements that, although the commodity prices and load forecast used by NS Power were dated, they were reasonable. Bates White said they did not observe any major changes regarding commodity futures prices that would require an update to the fuel rates, nor did they observe any major changes between the 2024 GRA Load Forecast and the 2025 Load Forecast that would warrant an update to the rates.

[58] As noted above, the cost included in NS Power's Base Cost of Fuel for NSPML's 2026 assessment is about $1.8 million greater than the FLG interest and principal amount identified by NSPML in its recent 2026 assessment application. In its compliance filing, NS Power is directed to remove that additional $1.8 million from its revenue requirement for 2026. NS Power is also directed to obtain an updated amount for the FLG interest and principal from NSPML for 2027 and remove any excess amount that was included in its 2027 revenue requirement.

[59] On the issue raised by REI, the Board recognizes that a pattern of actual fuel costs being higher than forecasted could present some challenges to participants in the Renewable to Retail market. NS Power's forecasts and results are reviewed by parties during related proceedings and by the Board's fuel auditor to identify any errors or inaccuracies. Despite those reviews, it is incumbent upon NS Power to continually refine its forecasting to minimize cost variances and the impact on customers and market participants. The Board expects NS Power will continue to work towards that objective.

3.2.2 FAM Plan of Administration and Fuel Manual

3.2.2.1 Plan of Administration

[60] In its application, NS Power requested approval of amendments to the FAM Plan of Administration as described in Section 6 and Appendix 6A and set out in Appendix 6B. On page 32 of the application, NS Power listed the proposed changes:

> Requested changes to the FAM Plan of Administration (POA) for the 2026-2027 GRA Period are described in **Appendix 6A** and set out in **Appendix 6B** (Redline and Clean versions). Proposed changes to the POA include cost of service changes to fuel costs to align with NS Power's COSS, the addition of customer renewable program credits (community solar energy credit rider) as an allowable fuel cost, the change related to the migration of customers to and from the FAM classes (as set out in section 13.10 [*sic*] below), and movement of some costs previously included in OM&G expenses to the FAM. There are also administrative changes to the main document to reflect the GRA period and a request to discontinue Appendix D, the calendar of FAM-related filings and events during the GRA Period. The dates for filings are set by the NSEB, and the FAM Small Working Group sessions are set a year in advance by NS Power. The timetable of events is no

> longer a useful part of the POA, as all the deadlines (except FAM Small Working Group meetings) are prescribed in the POA main document.
>
> [Exhibit N-3, p. 32]

[61] Regarding the proposed amendment to include costs associated with renewable energy programs in s. 3.2.8 of the Plan of Administration (POA), NSEB IR-33 requested comment on the appropriateness of including certain additional language in the proposed change. In its response, NS Power stated that adding "*when such costs cannot be recovered from program participants*" to part b) is helpful clarification which aligns with the underlying intent of that provision.

[62] In its response to NSEB IR-34, NS Power elaborated on some of the OM&G expenses proposed to be moved to the FAM, which were previously identified in its 2023 application to revise the POA (M11127). In that matter, the Board indicated that those OM&G costs could be given consideration for movement to the FAM during a subsequent GRA.

[63] In addition, NS Power noted that the Board's Decision and Order in the 2024 FAM AA/BA proceeding directed it to amend the FAM Tariff to account for both customers moving out of the FAM class and back into the FAM class since the previous FAM Tariff was only amended to account for customers moving out of the FAM classes. NS Power stated that it has amended Special Condition 3 of the FAM Tariff, included in PR-01 Attachments 1s and 2s, and Section 3.1 of the Plan of Administration as set out in Appendix 6B.

3.2.2.2 Fuel Manual and Hedging Plan

[64] On page 29 of its application, NS Power stated:

> NS Power's currently approved version of the Confidential Fuel Manual, which sets out the requirements for fuel and purchased power procurement, is included in Standardized Filing **OE-01F** and the Hedging Plan with a minor language change is included in **Appendix 5B**. The language of the preamble to Appendix Q (which is an overview of the Hedging Plan)

> in the Fuel Manual has been updated to refer to the plan in a generic way, rather than referencing specific years and filings which need to be updated. This is an administrative change only and does not affect the substantive content of the Fuel Manual or the Hedging Plan. NS Power seeks the Board's approval of this change in **Section 17** [*sic*] below.
>
> [Exhibit N-3, p. 29]

[65] Also, on pages 21 and 98 of its application, NS Power sought Board approval of administrative changes to the introduction to Appendix Q (the Hedging Plan) of the Fuel Manual.

[66] In NSEB IR-27 and IR-28, NS Power confirmed that it is responsible to prudently manage its fuel portfolio in the best interests of its customers, and the Board does not normally approve the Fuel Manual (including Appendix Q) and its Hedging Plan. Instead, it said that the changes were filed for informational purposes and that the changes are intended to continue beyond the prior “rate stability period”.

3.2.2.3 Findings

[67] NS Power is directed to make the change to s. 3.2.8 of the FAM POA discussed in NSEB IR-33. The Board approves NS Power’s other proposed amendments to the FAM POA and to the FAM Tariff.

[68] As noted above, the Board does not provide approval of the Fuel Manual nor the Hedging Plan, and again confirms that it is NS Power’s responsibility to ensure that it manages its fuel portfolio in a prudent manner, in the best interests of its customers.

3.3 Operating, Maintenance and General Costs

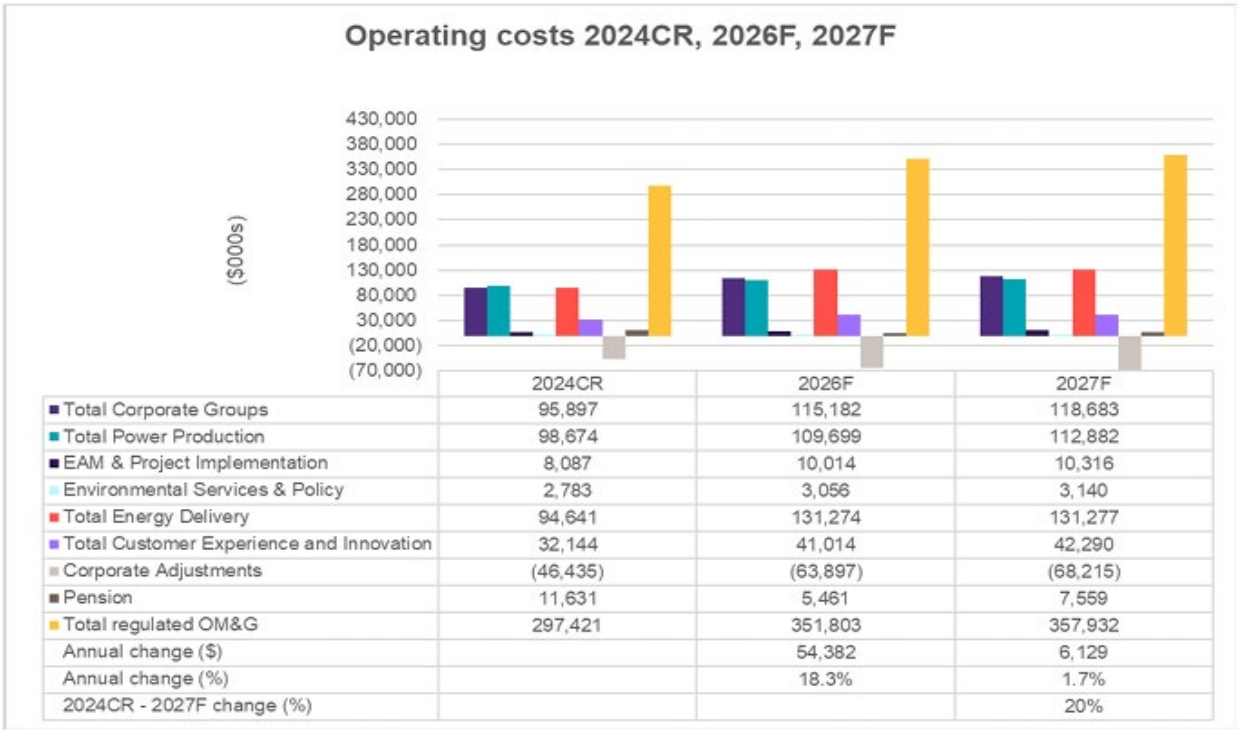
3.3.1 Overall Costs

[69] NS Power applied for an increase in its OM&G expenses in the test years. The OM&G expenses represent costs for operating and maintaining the utility’s generation, transmission, and distribution facilities; delivering service to customers; and providing corporate support to these functions.

[70] Compared to the amount of $297.4 million currently in rates for the restated 2024 compliance filing (2024CR), NS Power requests OM&G expenses of $351.8 million in 2026 and $357.9 million in 2027. This is an increase of $54.4 million (18.3%) from the 2024CR to 2026 and a further $6.1 million (1.7%) from 2026 to 2027.

[71] These operating costs are broken down by category in the following table for the 2024CR and the 2026 and 2027 test years:

Figure 9 – Operating costs by groups - 2024CR and 2026-2027 Forecast



	2024CR	2026F	2027F
Total Corporate Groups	95,897	115,182	118,683
Total Power Production	98,674	109,699	112,882
EAM & Project Implementation	8,087	10,014	10,316
Environmental Services & Policy	2,783	3,056	3,140
Total Energy Delivery	94,641	131,274	131,277
Total Customer Experience and Innovation	32,144	41,014	42,290
Corporate Adjustments	(46,435)	(63,897)	(68,215)
Pension	11,631	5,461	7,559
Total regulated OM&G	297,421	351,803	357,932
Annual change ($)		54,382	6,129
Annual change (%)		18.3%	1.7%
2024CR - 2027F change (%)			20%

[Exhibit N-33, p. 22]

[72] While not subject to review in this application because it is beyond the test period, NS Power forecasts OM&G costs to increase again from 2027 to 2028 by a further $22.1 million (i.e., 6.2%).

[73] The proposed 2026 and 2027 amounts already reflect a reduction of $9 million per year that NS Power agreed to deduct from OM&G costs in the settlement agreement. The utility agreed to reduce costs in the following amounts and categories:

- Energy Delivery - $5 million;
- Customer experience and Innovation - $2 million; and
- Corporate - $2 million.

[74] NS Power engaged its consultant, ScottMadden Inc., to prepare a benchmarking report to review how the utility is performing compared to its peers. ScottMadden concluded that NS Power's "OM&G costs compare favorably to the peer group" and that the utility "is in the first quartile for most metrics despite low usage per customer compared to peers".

[75] The proposed increases to OM&G expenses are due to various reasons, but a major cause for the increased costs arises from staffing increases. NS Power was asked in a Board IR to show a break down of the forecast full-time equivalent employees (FTEs) in the 2026-2027 test years in each operating expense category compared to the 2024CR. While the company cautioned that it had restructured parts of its operations since the 2023-2024 GRA filing and it was unable to directly correlate the FTEs in 2024 to match the updated structure, it confirmed there is a forecast net increase of 507 FTEs from the 2024CR to 2026, a 24% increase:

	2024 Compliance	2026 GRA	2027 GRA	2026 GRA vs. 2024 Compliance	% Change	Explanation
Executive Management	4	4	4	-	0	
Legal and Corporate Secretary	12	11	11	(1)	-8	
Corporate Finance	33	33	33	-	0	
Communications and Public Affairs	10	15	15	5	50	Note 1
Human Resources and Safety	50	63	63	13	26	Note 2
Facilities, Procurement & Security	70	86	86	16	23	Note 3
Information Technology	204	239	244	35	17	Note 4
Regulatory Affairs	18	17	17	(1)	-6	
East Coast Energy Initiative	0	40	40	40	N/A	Note 5
Total Corporate Groups	**401**	**508**	**513**	107	27	
Head Office	20	20	20	-	0	
Thermal Plants	291	340	340	49	17	Note 6
Tufts Cove & Combustion Turbines	104	100	100	(4)	-4	
Solar, Hydro and Wind Energy	74	94	94	20	27	Note 7
Biomass	31	32	32	1	3	
Energy, Fuel and Risk Management	32	34	34	2	6	
Total Power Production	**552**	**620**	**620**	68	12	
Enterprise Asset Management & Project Implementation	118	116	116	(2)	-2	
Environment	24	30	30	6	25	Note 8
Customer Operations/Energy Delivery	769	950	918	181	24	Note 9
Customer Service/Customer Experience & Innovation	251	398	400	147	59	Note 10
NS Power Total	**2115**	**2622**	**2597**	**507**	**24**	

[Exhibit N-27, NSEB IR-42, p. 2]

[76] NS Power noted that its current number of FTEs is 2,478 (as of the date of the IR response, November 5, 2025). It noted that the figures in the above table do not reflect the $9 million reduction in OM&G costs that the utility committed to remove in the settlement agreement. The utility also noted it had made a vacancy adjustment of $5.7

million in 2026 to recognize that not all these positions would always be filled. Further, in response to questioning from Port Hawkesbury Paper (PHP) counsel, the company acknowledged that the increase of FTEs in the above table reflects a net variance after accounting for the estimated transfer of 22 NS Power employees to the Nova Scotia Independent Energy System Operator (IESO Nova Scotia) in December 2025 in Phase 1 of the transition and 32 employees in 2027 in Phase 2 (Transcript, January 12, 2026, pp. 1056-1058).

[77] Doane Grant Thornton LLP was engaged by Board Counsel to review, among other matters, NS Power's proposed OM&G costs. Doane Grant Thornton stated that it analyzed the company's financial information and investigated variances between the 2024CR amounts and the 2026 to 2027 forecasts. It also reviewed "the methodology and assumptions used in the OM&G forecast for reasonableness" and reviewed the benchmarking studies for NS Power against its peers. However, in questioning by the Board at the hearing, the Doane Grant Thornton panel confirmed that it did not conduct an organizational review to determine whether there was a different operational structure that would be more cost-effective and efficient.

[78] The Nova Scotia Department of Energy said in its closing submissions that the proposed increase in FTEs was not reasonable in light of affordability issues faced by NS Power's customers and that the proposed staffing increase was not justified:

> 102. From the evidence in this proceeding, the Department submits that NS Power has not clearly justified the need for the number of staff it forecasts for 2026. Although NS Power indicated that cuts would be difficult from the company's perspective, the Company intends to reduce labour costs in some undefined areas to comply with commitments made in the Consensus Agreement.
>
> 103. The Department's position is that NS Power has not sufficiently justified the Company's departure from industry standards and asks that the Board critically consider reductions to NS Power's staffing request to eliminate any unnecessary burden on ratepayers.

> 104. Considering NS Power's large growth in overall FTEs since the last rate application, the Department asks that the Board critically consider reductions to NS Power's staffing request to eliminate any unnecessary burden on ratepayers.
>
> 105. The Department submits that NS Power, like other organizations operating in the current economic environment, should be required to demonstrate cost management and operational efficiency. Section 34A of the *Act* allows the Board to order a "Savings Review" of NS Power and that the savings review be conducted by an independent party. Considering the concerns identified in this proceeding about NS Power's increased spending with no clear justification, the Department submits that the Board should order a Savings Review.
>
> [Department of Energy Closing Submissions, January 30, 2026, p. 16]

[79] In its opening statement, the New Democratic Party Caucus asked the Board to examine the costs that the company is passing on to customers to ensure they are just and reasonable. It urged the Board "to do everything in its power to ensure Nova Scotians have affordable, reliable power and that Nova Scotia Power is held to the standard of ensuring they work in the interest of the public". In its closing submissions, the Liberal Caucus submitted that "an independent, comprehensive review of Nova Scotia Power's operations, governance, and long-term planning is warranted".

[80] NS Power noted that some of the proposed increases in OM&G costs are to address increased service requests by customers. For example, in the Regional Operations cost category, NS Power explained that population growth, an increasing number of customers, and load growth are reasons for a proposed $4.8 million increase from the 2024CR:

> Increased labour costs in Regional Operations in the 2026 forecast compared to the 2024 compliance are primarily due to additional resources required to complete customer requested work. The population growth in Nova Scotia has exceeded recent historical rates with 1-year average growth rates averaging 2.2 percent in 2021-2024 as compared to 0.5 percent in the preceding decade of 2011-2020. <u>This population growth has contributed to increased customer-requested work, which has increased by over 40 percent over the 2021-2024 period. There were 27,000 wiring permits, 44,000 electrical inspections, 4,400 renovations, and 8,400 new customer connection requests in 2024 alone. Also, additional resources are required for execution of the $1.3B Five-Year Reliability Plan and additional substations construction due to load growth.</u>
>
> …

> These additional labour costs were determined through a review of all field work that Regional Operations performed from 2020-2024. The population growth and electrification have led to a 40% increase in customer-requested work, and the Five-Year Reliability Plan has resulted in a $400M increase in transmission and distribution investment over the five-year period ($900M compared to $1.3B), which is an $80M per year increase. [Emphasis added]
>
> [Exhibit N-23, Doane Grant Thornton IR-34, pp. 1-2]

[81] In response to NSEB IR-12, NS Power stated that 65 community meetings were held across the province to discuss reliability and understand customer expectations. It said that no formal notes were taken during the sessions. At the hearing, it stated that these community meetings were conducted by NS Power's reliability team and supported by the communications group (Transcript, January 9, 2026, pp. 873-876).

[82] NS Power requested approval to increase its operational support for community and customer engagement. It has requested an increase in the Reliability Implementation group (Energy Delivery) of $2.5 million from the 2024CR to 2026, with a further $300,000 increase in 2027. Most of the increase (i.e., $2.1 million) is for increased labour costs for the Reliability Implementation department which was formed after the 2023-2024 GRA. This centralized the utility's resources focused on improving system reliability. The largest cost is for additional staff on the Standards & Community Engagement team to engage with customers to improve customer consultation, centralized reliability planning, and execution of the 5-Year Reliability Plan. The company indicated that the reliability team is comprised of 59 employees, who support both the operational and capital parts of this initiative.

[83] There is also a requested increase in OM&G costs for "Communications and Public Affairs" of $2.0 million from the 2024CR to 2026. This represents a 131% increase. NS Power explained that this is largely due to increased labour costs ($900,000) to create a new Communication and External Engagement department for increased

engagement with interested parties and communities across the province to receive input and feedback, and to share more information on priorities, projects, and initiatives undertaken by the company in response to customer feedback. In response to NSEB IR-61, the company said that through “more engagements such as community meetings and open houses, NS Power can gather feedback that can be incorporated into plans for work in the community”. It said it can use these sessions to provide updates on hydro projects and reliability upgrades and its 5-Year Reliability Plan. There are also additional proposed costs related to communications and community engagement for consulting fees ($700,000) and advertising expenses ($300,000).

[84] Similarly, in “Grid Modernization and Customer Integration” there is a proposed increase of $4.1 million from the 2024CR to 2026 (i.e., 68%) and a further $400,000 increase in 2027. According to its response to NSEB IR-69, part of the increase is related to activities of the Smart Meter Operations Center for data analytics support to provide operational reporting on Smart Meter Operations, respond to customer inquiries on billing and usage, and support the design and evaluation of customer programs. However, there is also a proposed increase for customer engagement and communications:

> The incremental labour for Customer Experience supports the maintenance of the expanding portfolio of digital solutions such as Green Button, My Energy Insights, the customer-facing website, and the large complex customer portal planned for 2026. In addition to the expanded digital channel support, the Customer Experience team is delivering a Customer First, role-specific training program to educate employees in delivering exceptional customer experience. The Customer Experience team is expanding its communication initiatives with customers via media campaigns and in-person engagements such as home shows to ensure customers have access to information and expertise in managing their energy needs.
>
> [Exhibit N-27, NSEB IR-69, p. 2]

[85] In NSEB IR-12, NS Power was asked whether it had measured customer satisfaction about reliability to establish a baseline against which to test the 5-Year Reliability Plan. It was also asked about any quantitative measures it had identified as it planned to begin to implement the Reliability Plan, including any data it had collected about how the company's reliability initiatives would impact customer satisfaction:

> While customer expectations provide valuable insights, NS Power does not anticipate using CSAT as a measure of the effectiveness of its Five-Year Reliability Plan. As detailed in the plan itself, NS Power is focused on the achievement of performance standards and has designed its investment tracks accordingly. NS Power anticipates that CSAT related to reliability concerns will be positively impacted by such investments by delivering decreased outage frequency and duration, but CSAT is not considered a consistent and repeatable reliability metric for benchmarking.
>
> [Exhibit N-27, NSEB IR-12, p. 2]

[86] NS Power's witness panel reiterated this position at the hearing:

> **Q.** So Nova Scotia Power is not intending to use a customer satisfaction metric in its reliability plan?
>
> **A.** (MacIntosh) Yes, Mr. Mahody, if you consider the CSAT metric and then how the Five-Year Reliability Plan was created, the Five-Year Reliability Plan was created based on meeting the Nova Scotia Power Performance Standards. So CSAT is not a performance standard; … Mr. Williams will add some additional context.
>
> **A.** (Williams) Yes, Mr. Mahody, I think the CSAT outcomes are certainly -- it's valuable data. It's customers' perspectives, which I've expressed already is something we take very seriously and that we attempt to address. But as Mr. MacIntosh has described, we have -- in the regulatory context, we have the performance standards, which we would view as, in part, being responsive to or aligned with customers' expectations in relation to reliable service. And so we believe that the performance standards -- I mean, the performance standards allow for there to be an objective benchmark. The CSAT outcomes are, like I said, certainly valuable, but much more difficult to have an objective benchmark with those, as opposed to the performance standards. And so that's why the performance standards are being used as the point in which we're measuring our success in relation to reliability. [Emphasis added]
>
> [Transcript, January 9, 2026, pp. 757-758]

[87] In support of the need for the Communications team to help other departments in their public engagement on reliability or other matters, NS Power stated:

> **A.** (Williams) … As I said, the groups we've discussed are all specialized groups, and so it's helpful when you go out to talk to the public to have -- just as when we appear before this Board -- to have the people that can respond to the questions that we anticipate receiving. So while we have a comms team that provides a communications and public affairs function and service to the company. They're not necessarily subject matter experts. And so while we could prepare those people to go out, it's more effective to provide the

> people that know the material more intimately and can provide the detailed responses that often times are customers are asking. And I think that's important, just as it is in this room, to instill confidence in those who are asking the questions that the company has commanded the subject matter and has a definitive direction on it.
>
> [Transcript, January 9, 2026, pp. 885-886]

[88] NS Power was also asked by the Board about its proposed increase of $3.4 million from the 2024CR to 2026 for Corporate Human Resources, and an additional increase of $200,000 in 2027. It said this is primarily due to increased labour costs for staffing level increases and salary escalation ($2.3 million). In response to Doane Grant Thornton IR-14, the company said it needed a larger Human Resource team to support the increased number of employees. It stated that the Human Resource and Safety teams have grown by a total of 10 employees, with more Safety Specialists, additional employees to support Diversity, Equity and Inclusion programs and Labour Relations, and more "Human Resource Business Partners to support talent acquisition and new employees". NS Power said that there is also $400,000 more for "talent management" which is handled by its parent Emera and allocated to the utility under the Affiliate Code of Conduct and Cost Allocation Manual (Doane Grant Thornton IR-16). There are also increased consulting costs of $300,000 due to the increased staffing levels, mostly for medical consulting expense.

[89] On the issue of shared services with its parent Emera, at the hearing the NS Power panel acknowledged that it had not evaluated whether it was more economic to provide the human resource functions with internal staff or to outsource them to a third party and operate on a shared service model (Transcript, January 12, 2026, pp. 1000-1001). Further, the ScottMadden benchmarking study filed by NS Power indicated that the utility's total human resource costs per FTE (as of 2023) was 21% higher than the industry group median.

3.3.1.1 Findings

[90] NS Power's proposed increase in OM&G costs is significant. It represents a 20% increase in 2027 (18.3% in 2026) from the OM&G costs included in rates approved in the 2023-2024 GRA. The burden is on NS Power to show that the proposed OM&G costs are just and reasonable and needed to provide the required service to customers.

[91] The Board is satisfied that some of the increased OM&G costs are warranted. One such example is in "Energy Delivery" for Regional Operations ($4.8 million) and Control Center ($3.3 million). This includes increased costs to deliver connection and inspection services to customers and operating new grid-scale battery sites. The Board accepts NS Power's evidence that there has been a significant increase in customer requests for such services. NS Power noted that there has been a 40% increase in customer-requested work in its Regional Operations field work, including for such services as wiring permits, electrical inspections, renovations and new customer connections. Further, it said additional resources are required for execution of the $1.3 billion 5-Year Reliability Plan and the construction of additional substations due to load growth. These services require more power line technicians, substation technicians, related apprentices, and supervisory staff.

[92] Further, NS Power's Regional Operations' costs must also increase to accommodate the three new grid-scale battery sites that are expected to be in service by 2026. This is required to allow the utility to meet renewable electricity standards (RES) requirements and to help integrate renewable generation on the grid and maintain reliability. Forecast costs to maintain these grid-scale batteries are $970,583 in 2026 and $1,247,406 in 2027 [Exhibit N-23, Doane Grant Thornton IR-35].

[93] There is also a 42% forecast increase in the Control Center category for labour expense in 2026 over 2024 actuals. However, NS Power explained that these additional resources are required immediately in the Control Center due to the significant increase in Independent Power Producer (IPP) interconnection requests and resulting from the FAM Audit Dispatch Study. NS Power noted that these additional employees are anticipated to transfer to the IESO Nova Scotia as part of the Phase 2 transition in 2027.

[94] In the circumstances, the Board finds the increased costs related to services like connection, inspection and interconnection requests are needed for the utility to provide the level of service expected by customers. Given the significant increase in customer requests for these specific services, the Board is satisfied that NS Power has responded appropriately by planning to add the required staff to meet the increased customer demand for these services so they can be provided within a reasonable time. As noted above, some increased operational costs also result from Board proceedings involving various customer representatives, including the FAM Audit Dispatch Study and the Interconnection processes matter.

[95] NS Power has also proposed increased OM&G costs related to addressing technology and cyber security matters. It proposed a total increase of $10.2 million from the 2024CR to 2026 and a further $1.8 million increase in 2027. These costs include a $6.6 million increase for more consulting fees to support the cyber security program for both its Operational Technology (OT) and Information Technology (IT). The additional costs also include $3.8 million for an incremental number of employees to support cyber security, the replacement of end-of-life legacy technology, and the introduction of new customer service. There is also $3.2 million more for increased rental and maintenance

equipment and software as new vendor tools and capabilities are added to the utility's information technology. The Board accepts the utility's evidence that these costs are necessary to keep its IT systems updated and that they are reasonable. The reality is that this is an issue all companies must address. However, the Board recognizes that there are currently proceedings underway about NS Power's cyber incident in the Spring of 2025 (Matters M12273 and M12600). While the Board approves the operational costs proposed in this GRA related to updating and operating the utility's technology, this approval does not foreclose a finding of imprudence in those cyber incident matters, if that is warranted, following the Board's review of NS Power's cyber preparedness and response.

[96] The Board has concerns about the transition of system operator staffing from NS Power to IESO Nova Scotia, including the potential for overlap and duplication. IESO Nova Scotia has forecast some transition costs for NS Power employees in its recent 2025-2026 (M12412) and 2026-2027 (M12663) revenue requirement applications. The Board will closely monitor this issue to ensure that ratepayers are not impacted by unnecessary costs incurred by these respective entities.

[97] However, the Board finds that NS Power has not demonstrated the need for its proposed increase in customer engagement and communications staff. First, the Board notes that NS Power appears to have been able to conduct its customer and community engagement with its present staffing complement, having conducted 65 community meetings recently across the province. The Board finds that adding more staff on these initiatives would be redundant.

[98] Secondly, and more importantly, despite the assertion that more staff is needed for customer engagement about issues like reliability, NS Power's witnesses confirmed that the company has not conducted formal surveying to measure customer satisfaction about reliability to establish a baseline against which to test its 5-Year Reliability Plan. The company confirmed it did not take any formal notes at its 65 community meetings to record the customers' expectations about reliability, although it did follow up on general action items with customers. However, company officials confirmed it will not measure customer satisfaction to determine the effectiveness of its Reliability Plan. Rather, NS Power is planning to rely on the achievement of performance standards and has designed its investments accordingly. It said measuring customer expectations "is not considered a consistent and repeatable reliability metric for benchmarking".

[99] Against this backdrop, the Board does not consider it reasonable to approve the company's request for additional staffing to conduct customer engagement, particularly about reliability issues, when it has no intention to measure customer satisfaction on the topic. Instead, it intends to base its conclusions about the success of the Reliability Plan on its performance metrics. Further, NS Power was unable to adequately explain how more costs were needed to support existing digital programs such as the My Energy Insights platform under the Grid Modernization and Customer Integration group. The utility also acknowledged in its testimony that it did not conduct any cost-benefit analysis about its customer engagement and communication initiatives or provide a plan outlining the measures or targets it hoped to achieve.

[100] To be clear, the Board considers it reasonable for the company to measure the success of its actions on issues like reliability by satisfactorily meeting its performance standards. That is likely one of the best methods to measure its success on such initiatives. However, the Board recognizes that customer engagement is beneficial. Nevertheless, an appropriate balance must be struck. Given the affordability concerns expressed in many letters of comment filed in this matter, the Board concludes that ratepayers consider the balance lies in not increasing engagement and communications costs at this time. Based on these letters of comment, customers do indeed care about reliability, but the Board concurs with the utility that achieving the performance metrics provides an objective measure of success on that initiative. Like many are forced to do in their daily lives, members of the public want NS Power to do everything possible to keep costs down where possible.

[101] The Board also finds that NS Power has not demonstrated that the addition of human resource staffing, and related costs, are warranted. The Board notes that the ScottMadden benchmarking study indicated that NS Power's OM&G costs per FTE were 21% higher than the industry group median (as of 2023). In questioning by the Board, the utility was unable to adequately explain why additional employees were required to support its Diversity, Equity and Inclusion programs. Further, in response to questions from the Board, NS Power acknowledged that it has not evaluated whether it is more economic to provide these services internally versus a third party or the shared services model it now has with its parent Emera. In the circumstances, the Board finds that the requested $3.4 million increase in 2026 (and $200,000 more in 2027) is not warranted.

[102] Based on the foregoing, the Board denies NS Power's proposed OM&G costs related to customer engagement, communications and human resource functions in the following amounts in the associated categories, with the reductions to be applied in each test year:

- Reliability Implementation (Energy Delivery) - $2,000,000;
- Communications and Public Affairs (Corporate Groups) - $2,000,000;
- Grid Modernization and Customer Integration (Customer Experience and Innovation) - $2,000,000; and
- Corporate Human Resources (Corporate Groups) - $2,000,000.

[103] The Board directs that the above $8,000,000 per test year reduction is to be reflected in a compliance filing. Further, the Board directs that these reductions are to be applied in addition to the OM&G reductions agreed to by NS Power in the settlement agreement. The Board notes that its directed reduction of OM&G costs in this decision does not deny NS Power's recovery of costs it has incurred. Rather, the effect of the Board's finding is to set the OM&G cost envelope that the utility is expected to operate within. The OM&G cost amount approved in this decision is what the Board has determined are reasonable costs for NS Power in 2026 and 2027.

[104] The Department of Energy submitted that the Board should order an independent savings review for NS Power under s. 34A of the *Public Utilities Act*, which would be conducted by a third party. The New Democratic Party and Liberal Party caucuses asked the Board to ensure that the costs requested by the utility are reasonable. They all highlighted affordability, as did most of the letters of comment received by the

Board. While the Board seriously considered the Department of Energy's request, it has decided, for reasons that follow, that such a review should not occur at this time.

[105] First, this general rate application has served as a thorough review of NS Power's operations. In terms of the Board's process, several expert consultants were engaged by Board Counsel to review different aspects of the application. This included Doane Grant Thornton, which conducted a thorough review of the OM&G costs, including a review of the methodology and assumptions used in the forecast of these costs. The Board also had the benefit of reviewing the benchmarking study prepared by NS Power's consultant, ScottMadden, which confirmed that the utility's OM&G costs compare favourably to its peer group and it "is in the first quartile for most metrics despite low usage per customer compared to peers". In one instance where the benchmark did not meet its peers (i.e., the human resource function), the Board has ordered a reduction in costs. Second, the application was preceded by lengthy negotiations between the utility and most of its customer groups, which resulted in a settlement agreement. Finally, the Board observes that different parts of NS Power's operations are reviewed on a regular basis, including the FAM audit every two years and the utility's annual performance standards report. In addition, there is a 5-year review of the performance metrics currently underway. There is also a separate review underway of NS Power's $1.3 billion 5-Year Reliability Plan. Also, since the last general rate application, the Board initiated a comprehensive inquiry under s. 30(5) of the *Public Utilities Act* into the extent, condition and value of the utility's property and assets. An independent study was conducted by Board Counsel consultant EA Technologies, who reviewed among other matters, the

utility's asset management practices. Accordingly, while the Board does not rule out a future savings review, it has decided not to order one at this time.

[106] Another issue raised at the hearing was the issue of executive compensation. While this is a matter relating to OM&G costs, it is dealt with separately in the next section of this decision.

[107] NS Power has forecast OM&G costs of $8.9 million at Trenton Unit 5 and Lingan Unit 2 during the test period due to a change in the retirement assumptions for these coal units and increased hours of operation. Given a number of issues related to these coal units, this item is also canvassed separately in this decision.

3.3.2 Executive Compensation

[108] The *Public Utilities Act* prohibits NS Power from recovering bonuses and incentives paid to an executive employee. Other remuneration may only be recovered as prescribed by regulation:

> **64B (8)** Nova Scotia Power Incorporated shall not recover from any rate, charge or fee approved by the Energy Board
>
> (a) any bonus or incentive compensation; or
>
> (b) any other remuneration, except remuneration that is prescribed by the regulations,
>
> paid to an executive employee of Nova Scotia Power Incorporated as identified in an approved report or determined by the Energy Board.

[109] The *Nova Scotia Power Incorporated Regulations,* NS Reg 231/2012, enacted on December 21, 2012, allow for the recovery of remuneration paid to executives as follows:

> **Salary and compensation recoverable from rates, charges or fees**
> **3** For the purpose of subsection 64B(8) of the Act, Nova Scotia Power Incorporated may recover the following remuneration from its rates, charges or fees approved by the Board:

> (a) for the Chief Executive Officer, no more than a salary equaling a 110% compa-ratio as provided for in the pay plan and no more than an additional 13% of the amount of that salary representing other benefits and compensation;
>
> (b) for each executive other than the Chief Executive Officer, no more than a salary equaling a 100% compa-ratio as provided for in the pay plan and no more than an additional 13% of the amount of that salary representing other benefits and compensation.

[110] The "pay plan" referenced in s. 3 of the regulations is the "Senior Officials Pay Plan approved by the Governor in Council by Order in Council 2007-85…as amended from time to time".

[111] By Order in Council 2023-138, dated May 9, 2023, the Governor in Council revoked the Senior Officials Pay Plan approved by Order in Council 2007-85 and approved a new Senior Officials Pay Plan. The new Senior Officials Pay Plan is materially different than the former plan.

[112] The former plan included two pay scales; one specifically designated for Associate Deputy Ministers and the other specifically designated for Deputy Ministers. Both scales on the former pay plan ranged from compa-ratios of 80% to 110%.

[113] The new Senior Officials Pay Plan includes five pay scales, all of which range from compa-ratios of 80% to 100%. None of these pay scales are specifically designated as applying to Associate Deputy Ministers, Deputy Ministers or a new class of Executive Deputy Ministers that was created around the same time that the pay plan was changed.

[114] In applying the *Nova Scotia Power Incorporated Regulations* to the new pay plan to determine the amount of executive remuneration it could recover through the rates that it charges to its customers, NS Power decided that the amount payable to executives other than the chief executive officer under s. 3(b) was the maximum amount payable

under the pay plan. NS Power calculated the amount recoverable for remuneration to its Chief Executive Officer as 10% more than the maximum amount payable under the new pay plan.

3.3.2.1 Findings

[115] Although the *Nova Scotia Power Incorporated Regulations* have not been amended and continue to refer to a repealed Order in Council, the *Interpretation Act* says the regulations continue to apply with reference to the replacement provisions relating to the same subject matter or to the repealed enactment as far as is necessary to give them effect:

> **Repeal and substitution by amendment or revision**
> **24 (1)** Where an enactment is repealed and other provisions are substituted by way of amendment, revision or consolidation,
>
> (b) a reference, in an unrepealed enactment to the repealed enactment, shall, as regards a subsequent transaction, matter or thing, be read as a reference to the provisions of the substituted enactment relating to the same subject-matter as the repealed enactment, but where there are no provisions in the substituted enactment relating to the same subject-matter, the repealed enactment shall be read as unrepealed as far as is necessary to maintain or give effect to the unrepealed enactment.

[116] The difficulty in this case is that, although the replaced provisions relate to the same subject matter, the pay plan is different enough that the regulations cannot be directly applied. At the same time, the pay scales in the former pay plan were also subject to periodic updates and, since the pay plan has been repealed, there have been no updates to the old pay scales. The guiding language in the *Interpretation Act* seeks to maintain or give effect to the unrepealed enactment.

[117] Under the former pay plan, NS Power was entitled to recover remuneration paid to its Chief Executive Officer at the maximum pay available to Deputy Ministers. As mentioned, NS Power's application of the new pay plan would allow the recovery of an

amount exceeding the maximum pay available to Deputy Ministers. As such, it is inconsistent with the previous intent. The maximum salary set out in the new pay plan is 100% of the SO5 scale. The Board finds that NS Power may recover this amount for remuneration paid to its Chief Executive Officer.

[118] Pending any amendments to the *Nova Scotia Power Incorporated Regulations*, the Board considers it appropriate to maintain the 10% differential between the remuneration allowed to be recovered for the Chief Executive Officer and other executive officers. The Board finds that NS Power may recover an amount equal to 90% of the SO5 scale for its other executive employees. NS Power is directed to make these changes in a compliance filing.

3.4 Depreciation

[119] Depreciation, in public utility regulation, is the loss in service value of an asset not restored by current maintenance, incurred in connection with the consumption or prospective retirement of the asset. As used in accounting, it is a method of distributing fixed capital costs over a period of time by allocating annual amounts to expense. Depreciation expense is an estimate of the consumption of the economic value of an asset over its expected service life. Assets with an expected service life greater than one year are typically capitalized and depreciated over their expected lives.

[120] Determination of an appropriate approach to depreciation requires significant judgement to be exercised by an expert in the selection of a depreciation procedure, method, and technique. To calculate depreciation expense, at least one procedure, one method, and one technique must be selected:

- Procedures are employed to systematically allocate an asset or assets into subgroups.

- The depreciation method determines how the depreciation expense will be allocated over the life of the asset. The simplest and most common example is straight-line depreciation, which provides for an even charge each year.
- Finally, a technique is selected to determine the specific asset life to be used in the depreciation formula. The two techniques most frequently employed by depreciation experts are the whole life and remaining life techniques. The whole life technique calculates depreciation expense over the entire life of the asset from inception to retirement. The remaining life technique calculates depreciation expense over the expected remaining life. Generally speaking, both techniques should arrive at the same level of depreciation expense, all else being equal.

[121] As it relates to regulation of depreciation, s. 38 of the *PUA* states:

> **Annual depreciation**
> **38** **(1)** Every public utility shall make provision for proper and adequate annual depreciation of its property and assets used and useful in furnishing, rendering or supplying each type or kind of service, and shall in respect thereof keep necessary and proper accounts.
>
> **(2)** Such annual depreciation shall be calculated by the straight line method or by such other method as the Board may from time to time prescribe.
>
> **(3)** Every public utility shall report to the Board the annual rates of depreciation from time to time applied to the several classes of property in such public utility.
>
> **(4)** The Board may ascertain and determine what are proper and adequate annual rates of depreciation of the several classes of property in any public utility, and such public utility shall thereupon and thereafter conform its depreciation account to the rates so ascertained and determined.
>
> **(5)** The Board may revise such rates of depreciation from time to time as it deems necessary or expedient.

Further, Sections 40 and 41 of the *PUA* state:

> **Regulations respecting depreciation**
> **40** The Board may also prescribe rules, regulations and forms of accounts regarding depreciation which a public utility is required to observe, carry into effect and follow.

Rates of utility to include allowance for depreciation
41 In fixing rates, tolls and charges to be paid to a public utility for any service, the Board shall include proper allowances for depreciation.

[122] NS Power owns significant assets, referred to as Plant, which were placed into service at different times. Due to the size and scope of the company's asset base, NS Power tracks its assets in pools at the mass property or location level. This methodology is standard in the electric utility industry, as tracking a significant number of assets on an individual asset basis is not practical and is cost prohibitive. NS Power's asset pools are depreciated over a period that approximates their estimated remaining useful lifespan. A fraction of each asset pool's original cost is treated as a depreciation expense each year until the asset investment and expected removal costs are fully recovered. Per the *PUA*, NS Power is permitted to recover its prudently incurred costs, which include depreciation costs over the estimated useful life of the assets. Depreciation expenses are included in customer rates, and the cost of the assets are thereby recovered from customers over the expected useful life of the assets.

[123] Depreciation expense for NS Power is comprised of both a depreciation and net salvage component. Depreciation recovers the original cost of any investment added into the utility's rate base, such recovery occurring over the expected useful life of the assets. Net salvage recovers the expected future costs to salvage and remove those assets, including any salvage proceeds, such recovery also occurring over the expected useful life of the assets.

[124] In its 2023-2024 general rate application, NS Power noted that a depreciation study would typically precede or coincide with a GRA process. However, prior to the 2023-2024 GRA, NS Power did not complete a depreciation study. NS Power stated the reason for this was the uncertainty surrounding the timing of retirement of the

coal plants having such a material impact on depreciation rates. As such, the company's depreciation rates had not been updated by way of a depreciation study since 2011 when intervenors and NS Power entered into a black box settlement agreement which was approved by the Board at that time. The black box agreement set depreciation rates to achieve an overall desired result of mitigating rate pressures without specifying the exact underlying means used to calculate the rates.

[125] As a result, in its *2023-2024 GRA* Decision, the Board directed NS Power to complete a depreciation study prior to filing its next GRA. NS Power complied with this directive by filing a new depreciation study as Appendix 8A [Exhibit N-7] in the current GRA. The depreciation study was completed by NS Power's consultant, Gannett Fleming.

[126] For most of NS Power's Plant accounts, the Gannett Fleming depreciation study, and the related proposed NS Power depreciation rates, are based on using the Equal Life Group (ELG) procedure, the straight-line method and the remaining life technique. For certain General Plant accounts, the proposed annual and accrued depreciation amounts are based on amortization accounting, which is discussed later in this decision.

[127] To meet federal and provincial decarbonization legislation, NS Power expects it will have to retire some of its existing coal-fired generating assets and associated marine unloading and fuel delivery facilities by 2030. However, NS Power has not yet fully recovered its investment in these assets, nor has it fully recovered the costs it will incur to decommission these facilities. While NS Power could seek Board approval to accelerate the recovery of depreciation expenses and decommissioning costs to match the remaining useful lives of the assets, doing so would cause a substantial increase in

rates. Therefore, to recover these energy transition costs in a more affordable manner, as part of its 2023-2024 GRA, NS Power proposed to transfer them to a regulatory asset, which is called a Decarbonization Deferral Account (DDA). To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.

[128] In a settlement reached between NS Power and representatives of all its major customer classes, the parties agreed in principle to a DDA that was narrower in scope than originally proposed by NS Power in its 2023-2024 GRA. As part of this agreement, NS Power was to develop policies and procedures for this DDA through a consultative process after the general rate application. The Board agreed with this approach in its *2023-2024 GRA* Decision and approved the DDA in principle.

[129] In Matter M11220, NS Power filed a DDA Manual, which set out the policies and procedures it proposed to follow to account for the unrecovered net book value (NBV) of assets and unrecovered decommissioning costs transferred to the DDA for future recovery. In that matter, NS Power sought formal Board approval of the DDA, as outlined in its DDA Manual. In its decision for the matter (2024 NSUARB 67), the Board approved the DDA with modifications. As part of the current GRA proceeding, NS Power said it intends to securitize the net book value of the assets within the scope of the DDA. This issue is addressed in a subsequent section of this decision.

[130] In the DDA matter (M11220), the Board did not direct NS Power to accelerate depreciation of coal generation assets currently in-service or to accelerate

amortization of any of the retired assets that will be transferred to the DDA. Instead, the Board directed NS Power to continue using existing depreciation rates for these assets until its next GRA proceeding when a new depreciation study would be filed. In effect, the Board's decision approved the future transfer of costs to the DDA, but the amortization of those costs remained to be determined. Therefore, in the interim there would have been no change to the revenue required from customers upon transferring costs to the DDA.

[131] Further, in Matter M11220, NS Power noted if its next depreciation study were to include the company's thermal assets, it would effectively require the acceleration of depreciation of those assets in a manner sufficient to recover the unrecovered costs over the expected remaining useful lives. NS Power believed that the accelerated depreciation expense required to recover these costs over this period would introduce significant rate increases for customers in the near term. The company also noted that it was continuing to seek funding from the federal government for some of its decarbonization costs. As such, increasing the depreciation expense to recover the costs over the expected remaining useful lives of the assets would not allow for consideration of any federal funding that may be received. NS Power, therefore, proposed that the thermal assets to be transferred to the DDA be excluded from the company's next depreciation study. All other assets not included in the scope of the DDA would be considered within the company's upcoming depreciation study.

[132] The Board agreed with NS Power's proposed depreciation study approach in Matter M11220 (DDA Manual). However, given the relatively small undepreciated balances of the Trenton 5, International Coal Pier, and Steam General Plant assets, the Board noted potential merit in accelerating depreciation of these assets so that they are

fully depreciated upon retirement. Therefore, while not directing accelerated depreciation of those particular assets at that time, the Board directed NS Power to include these assets in its next depreciation study.

[133] In the current GRA, NS Power has included all assets within its updated depreciation study for information purposes. However, consistent with the Board's finding in Matter M11220, NS Power did not update the depreciation rates associated with the assets within the scope of the DDA. The assets include Point Aconi, Trenton (including units 5 and 6 and common Plant), the Point Tupper Marine Terminal, Sydney International Coal Pier, and Steam General Assets. These assets are all intended to be retired before 2030 and, as such, are within the scope of the DDA. As noted previously, and as addressed in a later section of this decision, NS Power intends to securitize these assets. NS Power's remaining thermal assets, including Lingan, Point Tupper, Tufts Cove and Port Hawkesbury Biomass, are currently envisioned to provide service beyond 2030. They have, therefore, been included in NS Power's updated depreciation study complete with updated depreciation rates.

[134] The proposed depreciation rates in the updated depreciation study would result in NS Power having an annual depreciation expense of $385.2 million when applied to depreciable Plant balances as of December 31, 2023. The depreciation rates developed from NS Power's updated depreciation study, with consideration of the settlement agreement, are provided per asset account in Appendix "A" of the settlement agreement. The depreciation rates resulting from consideration of the settlement agreement produce an annual NS Power depreciation expense of $365.7 million when applied to depreciable Plant balances as of December 31, 2023. A summary table of

depreciation rates and expense resulting from the settlement agreement is presented in Figure 8-1 of the GRA, and reproduced as follows:

Function	GBV- Studied Plant (December 31, 2023) ($)	Accrual Rate	Total Accrual Amount ($)
Steam Production	2,616,967,386	6.47	169,219,037
Hydro Production	614,021,913	2.08	12,801,477
Solar	1,582,854	3.89	61,606
Other Production	492,589,726	4.50	22,182,232
Transmission	1,254,616,801	2.70	33,825,592
Distribution	2,137,686,386	3.45	73,717,352
General	740,996,013	7.27	53,887,702
Total	**7,858,461,079**	**4.65**	**365,694,997**

[Exhibit N-3, pp. 40-41]

[135] The figures in the table above include annual accruals calculated for all thermal assets, including those within the scope of the DDA. However, NS Power is not proposing to increase the depreciation rates for the assets included within the scope of the DDA, as the company intends to securitize those assets. This is summarized in the following table:

Function	GBV- Studied Plant (December 31, 2023) ($)	Accrual Rate	Total Accrual Amount ($)
Steam Production	2,616,967,386	2.62	68,461,258
Hydro Production	614,021,913	2.08	12,801,477
Solar	1,582,854	3.89	61,606
Other Production	492,589,726	4.50	22,182,232
Transmission	1,254,616,801	2.70	33,825,592
Distribution	2,137,686,386	3.45	73,717,352
General	740,996,013	7.27	53,887,702
Total	**7,858,461,079**	**3.37**	**264,937,219**

[Exhibit N-3, p. 41]

[136] Applying the proposed depreciation rates in the preceding Table to forecast monthly balances of depreciable Plant throughout the test period results in a forecast depreciation and accretion expense of $282.4 million in 2026 and $300.8 million in 2027.

If securitization of the assets included within the scope of the DDA had not been assumed by NS Power in its application, the depreciation and accretion expense to be paid by ratepayers would have increased annually by $26.6 million, resulting in totals of $309.0 million in 2026 and $327.4 million in 2027.

[137] In 2026, the depreciation and accretion expense is forecast to increase by $2.5 million over the 2024 GRA Compliance Filing. In 2027, the depreciation and accretion expense is forecast to increase by $18.4 million from the 2026 forecast amount. These increases result from updated depreciation rates and capital additions to Plant in service, as filed in the approved Annual Capital Expenditure Plans (ACE) and other capital expenditures approved by the Board. NS Power's average NBV was $4.456 million in the 2024 GRA Compliance forecast. In the updated test period forecast, the NBV has increased to $4.895 million in 2026 and $5.186 million in 2027.

[138] Dustin Madsen of Emrydia Consulting Corporation was engaged by Board Counsel to provide expert analysis, recommendations and testimony about NS Power's depreciation practices, including reviewing and assessing Gannett Fleming's depreciation study and proposed depreciation rates.

3.4.1 Settlement Agreement Reduction in Depreciation and Accretion Expense

[139] As noted above, the depreciation rates from the settlement agreement, result in annual NS Power depreciation expense being approximately $19.5 million lower than that calculated by the Gannett Fleming study, when applied to depreciable Plant balances as of December 31, 2023. This reduction results from changes to a) some of the estimated net salvage costs and rates in the Gannett Fleming study and b) some of the estimated asset service lives in the Gannett Fleming study. The Board must determine

whether these changes and the related reduction in depreciation and accretion expense are appropriate.

3.4.1.1 Net Salvage Costs

[140] Depreciation expense for NS Power includes both a depreciation and net salvage component. Net salvage recovers the expected future costs to salvage and remove/decommission assets, including any salvage proceeds. Gannett Fleming's depreciation study uses the Traditional Method for recovery of net salvage costs. This method of recovering net salvage costs embeds the recovery of net salvage costs over the life of the assets based on the approved depreciation parameters. The net salvage parameter in this case is expressed as either a positive or negative percentage based on the original cost of the asset.

[141] In his evidence, Mr. Madsen stated that the Traditional Method is the most technically correct and reasonable method of recovering net salvage costs from customers. He noted that linking the recovery of the cost to the depreciation of the assets ensures that the costs to salvage those assets are recovered over the lives of the same assets. Thus, it similarly ensures that the customers who benefit from the currently installed assets pay to remove those assets.

3.4.1.1.1 Production Plant

[142] As it relates to its generation assets, NS Power's depreciation study requires it to estimate the future cost of decommissioning its generation sites, as depreciation rates are generally set to recover the unrecovered decommissioning costs over the estimated remaining useful lives of the assets. In its current depreciation study, NS Power's net salvage estimates for production Plant reflect estimated

decommissioning costs associated with each generating station, including its hydro systems, based on site-specific decommissioning studies for each location.

[143] For Steam and Other Production Plant, the decommissioning studies were conducted by Stantec, Inc., an international engineering consulting firm. For Hydro Production Plant, the decommissioning studies were conducted by Hatch Ltd., a global, multidisciplinary management and consulting engineering company; Boreas Heritage Consulting Inc. reviewed archaeological costs; and J.B. Yates Engineering Limited reviewed partial decommissioning costs. The Hatch and Boreas studies were filed in this Matter in Exhibit N-7, while the Yates report was filed as Undertaking U-10.

[144] Generally, the collection of net salvage values in rates is based on current dollars at the time of the depreciation study and then inflated forward to the future years in which the costs are forecast to occur. However, per the GRA settlement agreement, decommissioning cost estimates for all production Plant have been calculated in 2024 dollars only (i.e., inflation to the forecast years of decommissioning has been removed). The settlement agreement also removes contingency costs from all production Plant decommissioning cost estimates. These settlement agreement changes result in NS Power’s proposed production Plant depreciation rates being lower than those calculated in the Gannett Fleming depreciation study.

[145] For NS Power’s Hydro Plant, the hydro decommissioning studies provided decommissioning cost estimates for full and partial decommissioning. A summary of these costs was presented in Exhibit N-7, Appendix 8E. Gannett Fleming’s depreciation study and NS Power’s proposed depreciation rates have been set using hydro decommissioning estimates based on the partial decommissioning scenario. Estimated

costs for partial decommissioning include removal and site remediation of buildings and structures, turbines, generators and auxiliaries, electrical services, and common services. The partial decommissioning estimated costs exclude costs for removal of structures required for water management, such as dams, spillways and gates.

[146] NS Power estimated the future cost to partially decommission the Wreck Cove, Mersey and Tusket hydro systems as $27 million, $228 million and $293 million, respectively, for a total of $548 million. However, given the magnitude of these costs and the broad policy, societal, and environmental considerations and factors that would need to be considered to decommission such sites, NS Power believes that removing these costs from customer rates, at this time, is a reasonable approach to balancing cost recovery and rate pressure for customers. As such, Gannett Fleming's depreciation study and NS Power's proposed depreciation rates further exclude any decommissioning costs for the Wreck Cove, Mersey and Tusket hydro systems. NS Power is only proposing to do so to the extent that it does not prejudice its ability to recover such costs in the future should they be prudently incurred.

[147] Finally, as per the GRA settlement agreement, archaeological reconnaissance costs have been removed from NS Power's hydro Plant partial decommissioning cost estimates. This settlement agreement change results in NS Power's proposed hydro Plant depreciation rates being further lowered from those calculated in the Gannett Fleming depreciation study.

3.4.1.1.2 Transmission, Distribution and General Plant

[148] Gannett Fleming's net salvage estimates for transmission, distribution and general Plant accounts were based in part on historical data compiled for the years 1993 through 2023. The net salvage estimates by account are expressed as a percent of the

original cost of Plant retired. Further, the historical net salvage data for the years 1976 through 1992 were available only in total for each of the transmission, distribution and general Plant functions. Therefore, though not considered as the statistical basis for the net salvage estimates, the data provided Gannett Fleming with some probative value.

[149] Specifically for NS Power's transmission and distribution Plant, the net salvage estimates were developed based primarily on Gannett Fleming's judgement, which considered a number of factors. The primary factors included an analysis of historical data; the net salvage characteristics of other electric utility properties; a knowledge of management's plans and operating policies; and net salvage estimates from previous studies of NS Power and other electric companies.

[150] The GRA settlement agreement made the following changes to Gannett Fleming's recommended net salvage rates:

- Reduced the Net Salvage Rate for Account 354.00 - Transmission Towers and Fixtures from 40% to 20%,
- Reducing the Net Salvage Rate for Account 355.00 - Transmission Poles and Fixtures from 60% to 20%, and
- Reducing the Net Salvage Rate for Account 365.00 - Distribution Overhead Conductors and Devices from 30% to 26%.

These settlement agreement changes result in NS Power's proposed depreciation rates for the related accounts being lower from those calculated in the Gannett Fleming depreciation study.

3.4.1.2 Estimated Average Asset Service Lives

[151] Key elements influencing the determination of depreciation expense are average asset service lives and survivor curves. Survivor curves (also referred to as Iowa curves) are a series of curves that have been developed to provide a statistical fit to the various lives of assets assessed in a depreciation study. These curves are broadly accepted and tested in North America and have been consistently accepted by regulators for determining reasonable depreciation expense. A survivor curve illustrates over time the percentage of the assets that are expected to continue to be in service. The selection of a specific survivor curve is informed by a depreciation expert's judgement regarding the visual and mathematical fit to a set of data points, peer data and discussions with utility company management and operations staff.

[152] In Gannett Fleming's depreciation study, the average asset service lives were estimated based on compiling historical data for the Plant accounts, analyzing this data through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group based on interpretations of the historical data analyses and the probable future.

[153] Gannett Fleming's service life estimates were based on informed judgement which considered a number of factors. The primary factors included statistical analyses of data; current company policies and outlook as determined during field reviews of the property and other conversations with management; and the survivor curve estimates from previous studies and other electric companies.

[154] The GRA settlement agreement made the following changes to Gannett Fleming's estimated average asset service lives:

- Increasing the estimated service life of Account 353 – Transmission Station Equipment from Survivor Curve 45-R2.5 to Survivor Curve 48-R2.5, which represents a service life increase of three years, and
- Increasing the estimated service life of Account 390.10 – General Plant Structures and Improvements from Survivor Curve 42-R2.5 to Survivor Curve 43-R3, which represents a service life increase of one year.

[155] These settlement agreement changes result in NS Power's proposed depreciation rates for the related accounts being lower than those calculated in the Gannett Fleming depreciation study.

[156] In his evidence, Mr. Madsen took issue with the recommended survivor curve for Account 353. As an alternative, he recommended a 50-R2.5 survivor curve for this account. This is discussed in more detail in section 3.4.3 of this decision. Mr. Madsen also recommended no change from the 42-R2.5 survivor curve for Account 390.10.

3.4.1.3 Findings

3.4.1.3.1 Exclusion of Wreck Cove, Mersey and Tusket Hydro System Decommissioning Costs from Proposed Depreciation Rates

[157] NS Power believes that removing the Wreck Cove, Mersey and Tusket hydro system decommissioning costs from customer rates, at this time, is a reasonable approach to balancing cost recovery and rate pressure for customers. The utility further emphasized that decommissioning these systems would entail extraordinary environmental, cultural, commercial, and social impacts, including large-scale habitat disruption, exposure of extensive shorelines, risks to hundreds of archaeological sites, loss of waterfront property and associated economic value, and potential impacts on potable water supplies. In addition, Wreck Cove plays a critical role in system reliability,

providing peak capacity, operating reserves, black start capability, and support for integrating renewable generation, making decommissioning particularly unlikely in the foreseeable future.

[158] Mr. Madsen identified a concern related to NS Power's proposed exclusion of these hydro system decommissioning costs from proposed depreciation rates. Specifically, he stated that under the proposal, future customers may be required to either pay a disproportionate amount of the costs to salvage the assets while they are still in use, or customers that no longer benefit from those assets will be required to pay for those assets. In effect, the proposal presents an intergenerational equity concern.

[159] This notwithstanding, Mr. Madsen supported NS Power's proposal to exclude these decommissioning costs from the proposed depreciation rates. In coming to this determination, he stated:

> … it is important to remember that the collection of net salvage in rates is based on a forward-looking estimate of the cost to salvage the installed assets. That estimate is often based on historical costs to salvage assets, inflated forward to the future years the costs will be incurred. The issue in this case as noted by NS Power in its Application, is that there is significant uncertainty whether the costs will actually be incurred. Indeed, having reviewed the detailed salvage studies and the policy, societal, and environmental reasons for why full salvage of the installed assets would not be in the public interest, I agree that the likelihood that the assets will be fully salvaged is low. [Emphasis added]
>
> [Exhibit N-34, pp. 111-112]

[160] In its response to NSEB IR-85, NS Power stated that it shared the intergenerational equity concern related to removing Wreck Cove, Mersey and Tusket hydro system decommissioning costs from proposed depreciation rates. However, until there is greater certainty about whether these costs will occur, the company believes the proposed approach to remove them from revenue requirement is a measured and responsible approach that helps to ensure rates are just and reasonable.

[161] Per NS Power's *2025 10-Year System Outlook Report* (Matter M12386), the Board notes that Wreck Cove is NS Power's largest hydro system. It has the ability to quickly provide 212 MW of peak capacity from two operating units and average annual generation of 300 GWh (soon to increase to 315 GWh). This represents approximately 8% of NS Power's forecast 2035 system peak, and roughly 3% of NS Power's forecast 2035 net system requirements. As NS Power noted, Wreck Cove also plays a critical role in providing required operating reserves, black start capability, and support for integrating renewable generation. In this context, the Board agrees with NS Power and Mr. Madsen that Wreck Cove is likely to be maintained indefinitely. Therefore, for the purposes of the current GRA, the Board finds that it is appropriate to exclude Wreck Cove decommissioning costs from the proposed depreciation rates.

[162] The Mersey Hydro System has a capacity of 42.5 MW, and an annual contribution of approximately 220 GWh toward NS Power's renewable energy targets. As noted in NS Power's 2026 ACE Plan, NS Power's 2020 Integrated Resource Plan (IRP) analysis compared the cost of rebuilding Mersey versus decommissioning it and replacing its energy and capacity contributions with alternative resources. Across all scenarios, redeveloping Mersey was more economic than decommissioning. The 2023 Evergreen IRP process reaffirmed these findings. The 2025/2026 IRP will provide an updated framework for evaluating the Mersey system, incorporating refreshed assumptions on load growth, emissions targets, resource costs and system integration. No final decisions on decommissioning or redevelopment of the Mersey system will be made until direction is received from the 2025/2026 IRP. With this in mind, the Board finds that it is appropriate to exclude Mersey decommissioning costs from the proposed depreciation rates for the

purposes of the current GRA. This can be reconsidered for NS Power's next depreciation study, should the 2025/26 IRP determine that decommissioning of Mersey is the preferred option.

[163] The Tusket system has a total capacity of 2.7 MW, and annual generation of approximately 12,000 MWh. This system is small compared to Mersey, and very small compared to Wreck Cove. As such, it may be questionable whether future refurbishment of this system is favourable compared to decommissioning and replacement with other less expensive renewable generation. However, the Board is aware that in the near term, NS Power intends to file an updated capital approval application for the Tusket Main Dam refurbishment. At that time, the decision to proceed with refurbishment or decommissioning will be tested by the Board. In the interim, for the purposes of the current GRA, the Board finds that it is appropriate to exclude Tusket decommissioning costs from the proposed depreciation rates.

[164] As noted previously, NS Power is only proposing to exclude decommissioning costs for the Wreck Cove, Mersey and Tusket hydro systems from customer rates to the extent that it does not prejudice its ability to recover such costs in the future should they be prudently incurred. The Board approves the exclusion of these costs for the 2026 and 2027 test years; however, its decision is limited to those years. How NS Power proceeds after the test years may be subject to further review.

[165] The above notwithstanding, the Board takes note of Mr. Madsen's evidence where he states NS Power's change in approach to recovering net salvage costs for these assets warrants that the company undertake an effort to fully reconcile all net salvage and actual salvage costs that have been recovered and paid for by customers. He

indicated that this information is important as NS Power will continue to seek to recover certain salvage costs for these assets and it is critical for parties to understand how much has been collected to date for the final (or terminal) salvage of the assets. He therefore recommended that NS Power provide a reconciliation showing the annual collection of interim and final net salvage in rates since the date the assets were installed. He also recommended that this same information be presented for actual interim salvage costs that have been incurred each year for each of the hydro assets where NS Power has proposed to cease collection of the final net salvage costs for the assets.

[166] During the hearing, NS Power was asked if it could provide this information. In response, Craig Flemming, Senior Director of Finance for NS Power, indicated that the utility has only been collecting the data required to facilitate the reconciliations recommended by Mr. Madsen since 2009. As such, he stated that the company could provide the information recommended by Mr. Madsen from 2009 onwards. The Board agrees with Mr. Madsen's recommendations and directs NS Power to provide this information from 2009 onwards in its next depreciation study filed with the Board.

3.4.1.3.2 Adjustments to Net Salvage Rates

[167] Mr. Madsen completed a detailed review of the net salvage rates proposed in Appendix "A" of the settlement agreement. Based on this review, Mr. Madsen did not recommend any changes to the proposed net salvage rates. Mr. Madsen stated that there were two primary reasons he reached this conclusion. First, he noted that while some of the proposed net salvage rates may be over or understated, there does not appear to be a clear directional bias in the proposed rates. In effect, he believes that the proposed net salvage rates are within a range of reasonably expected results.

[168] Second, as will be discussed in following sections of this decision, Mr. Madsen has recommended that NS Power adopt the Average Life Group (ALG) depreciation procedure, and that the company make changes to the estimated service lives for several of its asset accounts. If these recommended changes were to be directed by the Board, Mr. Madsen stated that they would result in a gradual and moderate, but not inconsequential, reduction of depreciation expense for NS Power. As such, he recommended that the Board allow the "dust to settle" from those proposed changes and then potentially reassess the proposed net salvage rates as part of NS Power's next depreciation study.

[169] For the most part, the Board agrees with Mr. Madsen's conclusion that the proposed settlement agreement net salvage rates are within a range of reasonably expected results. The Board's agreement applies to all Plant accounts for which settlement agreement adjustments were not made to Gannett Fleming's estimated net salvage rates, and to the three transmission and distribution Plant accounts to which net salvage rates were adjusted in the settlement agreement. The Board finds the proposed net salvage rates for those Plant accounts to be acceptable. However, for the reasons that follow, the Board has some concerns about the settlement agreement net salvage rate adjustments for Power Production Plant accounts.

[170] The settlement agreement removes archaeological reconnaissance costs from hydro system decommissioning estimates. Based on NS Power's response to NSEB IR-85, this results in a significant reduction in the related decommissioning cost estimates (when Mersey, Tusket and Wreck Cove are excluded) compared to the estimates upon which Gannett Fleming based its study. The Boreas archaeology report included in

Exhibit N-7 states that in developing archaeological cost estimates associated with decommissioning NS Power's hydro systems, it assumed archaeological reconnaissance would be undertaken for all systems "to identify and delineate real areas exhibiting high archaeological potential, to confirm the results of the background research and archaeological potential modelling, and to document any archaeological resources identified during the background study and/or encountered during the visual assessment, as per existing standards and best practice". In the event that an area was considered to exhibit low archaeological potential, archaeological monitoring could be recommended for the purpose of obtaining additional information and/or to confirm the results of the assessment.

[171] In the case of hydro system partial decommissioning, where removal of structures required for water management is not required, perhaps the related archaeological potential is likely low. If so, an assumption that archaeological reconnaissance costs would not be required might make some sense. However, beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide justification for such an assumption. Further, Gannett Fleming certainly included archaeological reconnaissance costs in its study to estimate appropriate depreciation rates. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these costs in the related decommissioning cost estimates.

[172] As it relates to the settlement agreement adjustment to remove contingency costs from generation decommissioning cost estimates, the Board refers to NS Power's 2018 Hydro Asset Study (HAS) (filed in NS Power's 2019 ACE Plan proceeding, Matter

M08984). The 2018 HAS is the information upon which Hatch relied upon to update its hydro system decommissioning cost estimates in the current GRA. On page 73 of Appendix B of the 2018 HAS, Hatch states “Contingencies are included in the estimates to provide for costs which cannot be specifically identified at the time of estimate preparation, but which can be foreseen with varying degrees of probability throughout the life of the project – i.e., contingencies are costs that are expected to be incurred”. Based on this statement alone, the Board sees no valid reason why contingency costs should be removed from generation decommissioning cost estimates.

[173] In addition, the Board notes that the thermal Plant, gas turbine Plant, wind production Plant and marine terminal and associated infrastructure decommissioning cost estimates included in the Gannett Fleming depreciation study were developed to an Association for the Advancement of Cost Engineering (AACE) Class 4 level. This Class level aligns with a level of project definition between 1% and 15%. As such, the related decommissioning costs estimates include a contingency allowance of 20% for wind production Plant and 25% for the others. Similarly, the hydro system partial decommissioning cost estimates included in the Gannett Fleming depreciation study were developed to a Class 5 level (per the Yates report filed as Undertaking U-10). This level estimate is typically based on a 0% to 2% level of project definition. The document upon which those cost estimates were developed does not identify the amount of contingency included in the estimates.

[174] Beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide support to exclude costs of such magnitude from generation Plant decommissioning cost estimates. Further, Gannett Fleming

certainly included contingency costs in its study to estimate appropriate depreciation rates. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these costs in the related decommissioning cost estimates.

[175] The settlement agreement also reflects forecast decommissioning costs for all generation Plant in 2024 dollars (i.e., it removes the effect of inflation to forecast years of decommissioning). In his evidence, Mr. Madsen notes that the collection of net salvage in rates is based on a forward-looking estimate of the cost to salvage the installed assets. That estimate is typically based on historical costs to salvage assets, inflated forward to the future years the costs will be incurred. As stated on page IV-3 of Gannett Fleming's depreciation study, this is, in fact, the methodology employed by Gannett Fleming in the current GRA. This suggests that Gannett Fleming, as NS Power's depreciation expert, believes it is appropriate to include these inflation costs in the related decommissioning cost estimates. Further, beyond the settlement agreement itself, there is nothing in the current evidentiary record before the Board to provide support to exclude inflation costs beyond 2024 from generation Plant decommissioning cost estimates.

[176] The Board also has other concerns about the settlement agreement adjustments made to net salvage rates for NS Power's production Plant assets. First, as identified in Mr. Madsen's evidence, NS Power currently has a significant reserve deficiency in its production Plant asset accounts. A reserve deficiency exists when the book accumulated depreciation reserve balance is below the calculated accumulated depreciation reserve balance. The book accumulated depreciation reserve balance reflects the amount of depreciation already collected in rates from customers, while the calculated accumulated depreciation reserve balance is the amount that NS Power

should have recovered in rates based on the applied depreciation and net salvage parameters.

[177] As identified by Mr. Madsen, NS Power has a $572,266,492 depreciation reserve deficiency in its production Plant accounts. This suggests that depreciation rates for production Plant assets have already been too low in the past. This difference will eventually need to be recovered from future customers, putting further upward pressure on rates in later years and potentially leading to intergenerational inequity. This is a concern.

[178] The Board is also concerned about the hydro system decommissioning cost estimates included in the depreciation study. As noted previously in this decision, Gannett Fleming's depreciation study and NS Power's proposed depreciation rates have been set using hydro decommissioning cost estimates based on partial decommissioning rather than full decommissioning. NS Power believes this approach is measured and responsible and helps to ensure rates are just and reasonable until there is greater certainty as to whether there is a realistic possibility that decommissioning of the assets, whether full or partial, will actually occur. The Board does not necessarily disagree with this premise. However, even under this approach, the Board is concerned about the accuracy of the hydro system partial decommissioning cost estimates upon which the depreciation study relied.

[179] NS Power stated in response to NSEB IR-85 that its proposed approach represents the lowest estimate of partial decommissioning costs, as it does not include any work on the civil aspects of the hydro systems, which tend to drive most of the decommissioning costs. This is concerning to the Board for two reasons. First, as the

“lowest estimates”, the partial decommissioning costs included in the depreciation study represent the minimum that current customers will pay for the related net salvage values. If partial decommissioning of any of NS Power’s hydro facilities is eventually undertaken, it is very likely that these “minimum” decommissioning costs will increase. If this occurs, the increased costs will be pushed on future ratepayers, resulting in intergenerational inequity and perhaps future ratepayers paying decommissioning costs for assets they may have never used.

[180] Second, the Board notes that the partial decommissioning cost in the Yates report for the Tusket hydro system was approximately $1.9 million. The Yates report is the document upon which NS Power relied to develop its hydro system partial decommissioning cost estimates for inclusion in its depreciation study. However, because of work currently being undertaken on the Tusket hydro system, NS Power developed a more detailed and updated partial decommissioning cost estimate for Tusket. This updated estimate is roughly $127.5 million, which is significantly higher than the estimate from the Yates report. This was discussed further during the hearing:

> **Q.** (Murphy) …There's a big gap in the difference between -- let's just talk about the partial decommissioning costs. There is a big gap in the partial decommissioning costs for Tusket that Nova Scotia Power has developed versus the partial decommissioning costs that the [Yates] Report developed.
>
> I can call up the page if you'd like from the [Yates] Report to show Tusket, but it's a big gap. Do you agree?
>
> **A.** (MacIntosh) Yes, sir. And I can elaborate on why that is.
>
> **Q.** Well, I — just let me ask my question first and then ——
>
> **A.** (MacIntosh) Sure.
>
> **Q.** —— you'll see where it goes.
>
> Given that there's a big gap in Tusket between the decommissioning costs that Nova Scotia Power says it's advanced further than all the other costs, how can the Board have any confidence that those other decommissioning costs that are based on the [Yates] Report are appropriate or accurate enough to include in depreciation rates?

> **A.** (MacIntosh) Yes, it's a good point, Mr. Murphy. We did respond to this in IR-85, Part B that's in 27, Board IR, it's that same IR we had up, but we did recognize that the partial decommissioning costs that were included would be the minimum. So in the terms of Tusket, the scope of work for partial decommissioning was a different scope of work than we would have included in the scope of work for the partial decommissioning estimates of the other sites.
>
> So in terms of Tusket, the Tusket partial decommissioning estimate includes civil works, so includes work with water retaining structures, dispatches associated. The partial decommissioning estimates that we've submitted for the GRA purposes have a much minimum — a smaller scope of work.
>
> So your point is that, yes, it is smaller based on the scope of work that we did include.
>
> **Q.** So it'd be fair to say that the partial decommissioning costs for these other smaller assets would probably be a lot higher.
>
> **A.** (MacIntosh) If there was the requirement to expand the scope of work beyond the generator and the turbine and the runner. So if you could just decommission the site and the powerhouse without having to expand the footprint in the civil structures, then it could be reasonable. But if there was a requirement to expand the scope like Tusket, then obviously the investment would be higher.
>
> [Transcript, January 7, 2026, pp. 299-302]

[181] The Board understands the position expressed by NS Power during this exchange. However, given the experience at Tusket, the Board takes no comfort that other hydro systems will not encounter similar issues as Tusket under a decommissioning scenario. In that event, partial decommissioning costs for other hydro systems would be much higher than the costs currently included in NS Power's depreciation study. Again, the increased costs would be pushed on future ratepayers, resulting in intergenerational inequity and perhaps future ratepayers paying decommissioning costs for assets they may never have used.

[182] Another issue of concern to the Board relates to the aftermath of a partial decommissioning scenario. In the partial decommissioning approach put forward by NS Power, structures required for water management, such as dams, spillways and gates, would remain in place while the related hydro system would no longer generate power. These structures would continue to incur sustaining capital upgrade costs and continued

maintenance costs to ensure they remain safe. However, the assets themselves would no longer be considered “used and useful” from a ratepayer perspective. This raises the issue of who would be responsible for the on-going costs for assets no longer used and useful – ratepayers, NS Power shareholders or others who may benefit from maintaining this infrastructure? This was discussed during the hearing:

> **Q.** (Murphy) Would it be fair to say in the partial decommissioning scenario that there would be ongoing O&M costs and capital sustaining costs associated with any of the assets that are not decommissioned, particularly the dams, spillways, water retaining structures?
>
> **A.** (Williams) Yes, even if there wasn't any generation coming from those sites, Nova Scotia Power, if they owned those assets were still required to maintain the safe operation of those assets and there would be an OM&G costs associated with it.
>
> **Q.** And ongoing sustaining capital costs as well.
>
> **A.** (Williams) Correct.
>
> **Q.** And would you agree that once those assets are partially decommissioned they are no longer used and useful?
>
> **A.** (Williams) Yes, I think generally speaking, sir, we would agree with that, and I think that gets to the point of where we're going with some of these hydro discussions, that there needs to be a broader discussion of how these are handled in the future, and if they are to be decommissioned whose responsibility ultimately that would be both as in the decommissioning phase of them, but also after that in maintaining them.
>
> So I would agree that there’s a — an inconsistency, perhaps, with traditional or normal utility practice if those were to be partially decommissioned and retained as assets of the utility.
>
> **Q.** Right. If they were no longer used and useful and there was any further costs, ongoing O&M costs, capital sustaining costs as a no longer used and useful asset, any of those costs would typically be the responsibility of Nova Scotia Power and shareholders. Correct?
>
> **A.** (Williams) And that's why I say I think traditionally our normal course, but I think there would need to be a recognition that those assets are not the same as -- and this is the discussion I think mainly with some of the larger assets, where if those structures were to be retained whose responsibility ought those to be. It's not the same as a generation asset in the middle of a field where you just reclaim it and it becomes brownfield and you can walk away from it, or sell the land, it's different than that. I think there would need to be a broader discussion of how those assets were handled.
>
> **Q.** So you're suggesting that perhaps ratepayers should be on the hook for some costs associated with assets that they get absolutely no benefit from.
>
> **A.** (Williams) So I wouldn't put it like that, sir, but that probably doesn't surprise you. I think in that scenario there would be a benefit to ratepayers, which is we would be doing

> something that, you know, otherwise if we fully decommissioned it, the partial decommissioning would be a lower cost to customers. So there would be a benefit to customers, but not in the sense of it's providing a service to customers, but the benefit would be there.
>
> And I think when I say, you know, a broader discussion, I think it's a broader discussion within the province of how those would be handled if we were in a position where we were partially decommissioning assets, and to your point, which is a good point, no longer producing electricity or providing a traditional utility function, but there would be a benefit.
>
> [Transcript, January 7, 2026, pp. 305-308]

[183] Finally, the Board understands NS Power's rationale for including partial rather than full hydro system decommissioning costs in its depreciation study. Whether full decommissioning is even possible or feasible at some of NS Power's hydro systems is uncertain. Nonetheless, there is no certainty that partial decommissioning for some systems will prove to be the preferred choice over full decommissioning. In Undertaking U-11, NS Power provided a copy of its depreciation calculations under the assumption that full decommissioning of hydro systems would be required. The Undertaking reveals that under a full decommissioning scenario for all hydro systems excluding Mersey, Tusket and Wreck Cove, depreciation rates would be approximately $65 million higher than those in the settlement agreement.

[184] In the Board's opinion, the settlement agreement adjustments to production Plant net salvage rates appear simply as a means to reduce the effect of depreciation on revenue requirement in the short term, which by implication is at the expense of future customers. The self-interest of some parties to the agreement in deferring costs to future customers is understandable, but it does create intergenerational inequity concerns.

[185] As identified in NS Power's response to NSEB IR-87, the net effect of settlement agreement adjustments to NS Power production Plant net salvage rates results in a revenue requirement reduction of $10.6 million in 2026 and $11.7 million in

2027. If the Board were not to approve these adjustments, it would result in an average rate increase of roughly 0.5% to the rates filed in the settlement agreement. This would be an unfortunate impact, but the Board believes it could address intergenerational concerns.

[186] The Board notes that implementation of other depreciation related issues it is addressing in this decision could more than offset this increase. However, all of this must be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its funds from operations: debt credit metrics even further. This could increase the risk of having credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[187] Further, at this point there remains considerable uncertainty related to current decommissioning cost estimates for these assets. This is particularly true for NS Power's hydro assets, where it remains uncertain whether these assets will eventually undergo partial or full decommissioning, or even be decommissioned at all. As noted above, the Board has directed NS Power to address this issue before its next GRA. Given this uncertainty, the potential impact, if any, of assumed production Plant net salvage rates on future ratepayers is unclear. In this circumstance, the Board accepts the proposed settlement agreement adjustments to net salvage rates for NS Power's production plant accounts. Therefore, for the purposes of the current GRA, the Board also

finds that the proposed settlement agreement changes to the net salvage rates and decommissioning costs are appropriate.

[188] This notwithstanding, as NS Power rightly noted in its closing submissions, there currently remains no settled policy or a multi-stakeholder framework for determining whether, when, or how full or partial decommissioning of hydro facilities should occur, nor who would ultimately bear responsibility. NS Power further stated:

> … NS Power views the present proceeding as a necessary first step in advancing the conversation of the future of hydro in the province and the Company acknowledged its responsibility to initiate a broader, structured discussion involving regulators, government, and other relevant stakeholders. At the same time, the Company was clear that neither the outcome nor the timeline of that process is within its sole control. Further, in the Nova Scotia Independent Energy System Operator-led Integrated Resource Plan (IRP), NS Power's existing hydroelectric units will be evaluated based on historical hydrology, operational and environmental constraints, physical limitations, and their energy and capacity contributions which will help inform this important discussion.
>
> In these circumstances, NS Power submits that the prudent course is to proceed on the basis proposed in this Application, while establishing a forward process, including appropriate Board oversight and reporting, to ensure that this important and complex issue impacting all Nova Scotians is addressed in an orderly, transparent, and coordinated manner.
>
> [NS Power Closing Submissions, pp. 53-54]

[189] The Board agrees with NS Power's proposed approach to address this issue. If this broader interested party engagement demonstrates decommissioning of hydro assets is a potential path or option, then the relevant costs can be included in the revenue requirement to be approved in NS Power's next general rate application. The Board directs NS Power to undertake this interested party engagement process, with an ideal target completion date in advance of NS Power's next GRA. During this process, the Board directs NS Power to file regular update reports with the Board every six months, beginning October 1, 2026.

3.4.1.3.3 Adjustments to Estimated Asset Average Service Lives

[190] In his evidence, Mr. Madsen proposed a number of changes to Gannett Fleming's recommended estimated asset average service lives. This is discussed in more detail in section 3.4.3 of this decision. For the reasons described in that section, the Board does not approve Mr. Madsen's proposed service life adjustments. This notwithstanding, the Board notes that the proposed settlement agreement change for Account 353 (Transmission Station Equipment) moves the estimated average asset service life for that account closer to that recommended by Mr. Madsen. The Board also notes that although Mr. Madsen recommended no change to the average asset service life for Account 390.10 (General Plant Structures and Improvements), he did state that peer data supports a life extension to some degree. The Board observes that the proposed settlement agreement change for this account does, in fact, extend the service life slightly.

[191] Considering the above, for the purposes of the current GRA, the Board finds that the proposed settlement agreement changes to the average service lives for NS Power's asset Account 353 and Account 390.10 are appropriate.

3.4.2 Calculation of Depreciation Expense (ELG vs. ALG)

[192] As noted previously, NS Power's updated depreciation study has used the Equal Life Group procedure to calculate proposed depreciation rates. NS Power has used the ELG procedure for the past 32 years, and Gannett Fleming has recommended its continued use. The ELG procedure calculates depreciation of individual assets or subgroups of assets within the same account that share the same or similar expected service life. The procedure relies on estimating retirement dispersion patterns and applying Iowa curves to model when assets are expected to retire, with depreciation rates

reflecting those expected retirement patterns. Under ELG, assets that are expected to retire sooner are depreciated more quickly, while longer-lived assets are depreciated more slowly.

[193] An alternative to the ELG procedure is the ALG procedure (also known as the Average Service Life procedure). ALG is a procedure that calculates depreciation using a single average service life for all assets within an account or asset group, rather than assigning different lives to individual assets or subgroups. Depreciation for the asset group is calculated using the straight-line method over the estimated average service life. The estimated average service life is typically derived from a combination of engineering judgement, historical experience, and the use of accepted Iowa survivor curves. Using ALG, each asset in the group is treated as contributing equally, on average, to the overall consumption of service value.

[194] Regardless of the depreciation procedure selected, the purpose of the exercise is to depreciate the same amount of investment over the expected life of an asset. While the amount charged in any one period may vary by virtue of the procedure selected, the total amount of depreciation recovered over the full life of the asset will not vary regardless of which procedure is used.

[195] Gannett Fleming's depreciation study states that the ELG procedure provides a better match of depreciation expense and loss in service value than the ALG procedure. In Gannett Fleming's opinion, ELG seeks to align depreciation expense more closely with the forecast retirement pattern of assets as a means of trying to match cost recovery with estimated asset consumption. In comparison, Gannett Fleming notes that a characteristic of the ALG procedure is that the cost of Plant retired prior to average life

is not fully recouped at the time of retirement, whereas the cost of Plant retired after average life is more than fully recouped. However, over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

[196] In his evidence, Mr. Madsen acknowledged that both ELG and ALG are acceptable and appropriate procedures to determine depreciation expense. However, he argued that ALG provides for a more gradual, moderate and equitable recovery of depreciation. He believes this is important, as it allows for some moderation of potential changes in the depreciation recovered over the life of the assets, particularly as lives are lengthening. Mr. Madsen believes this “lengthening” is becoming common, particularly for transmission and distribution assets, where utilities are replacing significantly older assets with much newer assets that often have much longer service lives.

[197] Mr. Madsen contends that ELG front-loads depreciation expense and is highly sensitive to changes in asset lives and retirement assumptions. He stated that a common argument against ELG, which he agrees with, is that it ignores that the benefits of most electric utility assets with regular maintenance do not decline considerably in later years as the ELG procedure suggests. As asset lives lengthen over time, Mr. Madsen argued that ELG will over-recover depreciation early, requiring later corrections. He stated that this can create intergenerational inequity, where current customers pay more than their fair share of depreciation costs while future customers pay less.

[198] Mr. Madsen's evidence describes what he believes to be the pros and cons of the ALG and ELG procedures. The Board has summarized this evidence as follows:

Procedure	Pros	Cons
Average Life Group (ALG)	**Simplicity**: Simple to apply and easy to understand.	**Lower early-period cash flows**: Depreciation expense is lower in earlier years compared to ELG, with higher depreciation occurring notionally in later years.
	Less potential volatility: Year-to-year changes in retirement data are less likely to materially affect depreciation expense unless they indicate a change in average service life.	**Accuracy:** Because ALG is less sensitive to survivor curve selection, incremental refinements to depreciation estimates are not as easily implemented.
Equal Life Group (ELG)	**Accuracy**: • Can appear more precise where asset lives are known and do not change. • May provide for more refined depreciation expense and increased accuracy, thereby allowing more variation in depreciation expense than charged under ALG.	**Greater sensitivity and variability**: Results are more heavily influenced by retirement data, which increases the risk that depreciation estimates deviate from actual retirement experience.
	Improved cashflow: Accelerates depreciation expense, improving near-term cash flow metrics and reducing reliance on near-term debt and equity financing.	**Complexity**: ELG is a complex procedure which can continue to be difficult for some parties to understand if they are unfamiliar with depreciation procedures, the derivation of Iowa curves, and the importance of retirement data.
		Potential incentive effects: Accelerated recovery may alter utility incentives, including the timing of capital replacement decisions.

[199] Mr. Madsen does not accept that NS Power's use of the ELG procedure inherently provides a better match between depreciation expense and loss in service value than the ALG procedure. Therefore, Mr. Madsen has recommended that NS Power

move to using the ALG procedure for all assets. He is supportive, however, of NS Power continuing to use the remaining life technique. Mr. Madsen contends that ALG is preferred to ELG because it better protects against over-collection, reduces volatility, and avoids unfair cost shifting between customer generations. In response to Emrydia IR-27, NS Power provided the following table depicting the change in 2026 and 2027 depreciation rates if it used the ALG procedure rather than ELG:

Depreciation and Accretion Expense

($ Millions)	Per GRA Settlement Agreement		Per Depreciation Rates calculated under ALG	
	2026	2027	2026	2027
Steam	48.0	49.9	48.7	50.6
Gas Turbine	9.9	10.6	8.9	9.6
Wind Turbine	13.3	13.3	13.3	13.3
Hydro	16.6	17.3	17.9	19.1
Solar	0.1	0.1	0.1	0.1
Transmission	47.7	52.1	46.7	51.1
Distribution	85.4	89.6	64.6	67.8
General Property	61.5	67.9	59.0	65.0
Total	**282.4**	**300.8**	**259.1**	**276.5**

[Exhibit N-31, Response to IR-27]

[200] During the hearing, however, Mr. Flemming confirmed that the above table does not provide a true “apples to apples” comparison. Specifically, he noted that the ALG rates do not reflect the depreciation related adjustments made in the settlement agreement. These adjustments would further increase the difference between the two methodologies by approximately $20 million in each of 2026 and 2027. As such, including the settlement agreement adjustments, Mr. Flemming noted the ALG rates would be approximately $40 to $45 million lower than those under the ELG. The rates for both procedures also assume the securitization of the assets within the scope of the DDA will proceed.

[201] During the hearing, Mr. Flemming indicated that a $20 million reduction in annual depreciation expense would equate to a one-time pre-tax decrease of roughly 1% in average rates.

3.4.2.1 Findings

[202] John Wiedmayer, of Gannett Fleming, and Mr. Madsen agree that ELG and ALG are both acceptable and appropriate procedures to determine depreciation expense. They also agree that both procedures require the use of significant judgement by depreciation experts. In addition, they have no dispute that although the timing of depreciation recovery varies, the total amount of depreciation recovered over the full life of an asset will be the same regardless of which procedure is used.

[203] Mr. Wiedmayer and Mr. Madsen also agree that the majority of North American electric utilities use the ALG procedure. However, both also noted that ELG is an accepted procedure by a number of utility regulators. Mr. Madsen stated that the ALG procedure is much more common in the United States. He also referenced several recent cases where requests to convert from the ALG to ELG have been denied. These include Manitoba, Ontario, New York, Mississippi, as well as other jurisdictions. Mr. Wiedmayer stated that ALG has a longer acceptance primarily due to the fact that it offered a simpler means to complete depreciation related calculations. However, with the advent of today's modern computers, ELG calculations have become easier to complete, resulting in more use of the procedure. He also noted that ELG is currently used in Alberta and Newfoundland. His evidence also indicated that ALG is used by Maritime Electric in Prince Edward Island.

[204] For this GRA, NS Power submitted that it has appropriately applied the ELG procedure using the straight-line method, as it has done previously for over 30 years. The

company believes ELG is superior to ALG as its use has and continues to lower NS Power's rate base and thus, financing costs at a more accelerated pace, and the data used reflects real retirement data experienced by the company. In its closing submissions, NS Power has framed the argument over which procedure is most appropriate as follows:

> Overall, the difference between the witnesses is not whether judgment is required, but whether a calculation procedure that explicitly incorporates utility-specific retirement experience by asset age is preferable, on balance, to one that relies on averages, and further the degree to which the resulting impact on rate base ought to be a consideration in choosing the appropriate calculation procedure.
>
> [NS Power Closing Submissions, p. 19]

The Board will first address the issues raised in NS Power's framing. The Board will then address intergenerational equity, which it believes is also an important issue in assessing ALG vs. ELG.

[205] As it relates to a procedure that uses utility-specific retirement experience, in his hearing testimony Mr. Wiedmayer stated that his depreciation analysis relied on NS Power's actual retirement and aged data wherever reliable records exist. He identified this period as beginning approximately in 2009, when NS Power started recording age-at-retirement information. He explained that retirements from that time forward include both vintage year and retirement year and, therefore, constitute true aged data that is used directly to inform survivor curve selection and service life estimates. For earlier years and older vintages where fully aged data records do not exist, he testified that standard "simulated aging" techniques were used to supplement the record. He characterized this as a common and unavoidable feature of long-lived utility Plant.

[206] Mr. Wiedmayer emphasized that simulation techniques are designed to reasonably approximate asset age distributions and retirement patterns when direct data are unavailable. In addition, he noted that simulated data do not displace actual NS Power

aged or retirement data where it exists but instead fill unavoidable gaps in the historical record. He asserted that the combined use of observed and simulated data is consistent with accepted depreciation practice and sufficient to support the application of the ELG procedure.

[207] In his testimony, Mr. Madsen acknowledged that the use of simulated data is preferable to relying solely on unaged data, and he cited the National Association of Regulatory Utility Commissioners (NARUC) Manual to confirm that statistical aging techniques are widely accepted in regulatory practice. However, he also emphasized that simulated data is inherently an approximation, depends heavily on assumptions about initial age distributions and survivor curve shapes, and may smooth or predetermine results in ways that mask true retirement behavior. Mr. Madsen's core concern was not that Gannett Fleming's use of simulated data is improper, but that placing significant weight on that simulated data, particularly combined with the ELG procedure, increases the risk of error.

[208] While acknowledging that ELG is often described as aligning depreciation more closely with retirement patterns, Mr. Madsen argued that this claim depends on the reliability of retirement data. Specifically, he contends that when retirement ages are simulated rather than observed, as is the case for much of NS Power's Plant data, ELG's greater sensitivity to this data can create an appearance of precision that is not grounded in actual service value loss. Mr. Madsen testified that in such circumstances, ALG's smoother allocation of depreciation may provide an equally reasonable and, in his view, more prudent approximation of service value consumption. This is because it avoids over-weighting of assumptions embedded in simulated data and because ALG is less sensitive

to the shape and timing of assumed retirement curves. In effect, Mr. Madsen does not accept “better matching” as an advantage of ELG. Instead, he framed it as a conditional claim that weakens when based on simulated plant data rather than long-standing observed experience.

[209] Considering the above, the Board does not believe that Mr. Madsen’s is suggesting that ALG offers a theoretically superior mathematical calculation of depreciation expense vs ELG. Instead, he argues that in the absence of a solid foundation of actual observed aged asset data, the ELG procedure exacerbates the potential error in calculating depreciation expense when simulated aged data is relied upon. This was discussed further in the hearing:

> **BY MEMBER MURPHY: …**can you tell me why the ALG procedure doesn’t exacerbate the potential errors associated with using simulated age data in the same way that the -- that you claim the ELG procedure does?
>
> **A.** (MADSEN) Certainly. So again, if the simulated age data does not accurately reflect the actual retirement pattern of those assets -- and they wouldn’t because the simulated data is a guess, is a best guess. And again, going back to the example we just walked through, it -- the ELG procedure’s going to be based off of those specific datapoints that are simulated.
>
> If those datapoints are incorrect, the ELG procedure is going [to] accelerate depreciation based on the assumption that those datapoints are correct, and that is where the error comes in. Whereas the Average Life Group, again, does not depreciate based on that curve; it depreciates on the assumption that there will be an average amount of depreciation taken in each year.
>
> And that’s why when there’s a variation from year to year in those datapoints, the Average Life Group procedure tends not to overemphasize or put undue reliance on that variation, particularly if there is a risk that the age data that you’re relying upon in this case, the simulated age data, might be incorrect.
>
> I know during the hearing, Mr. Murphy, you looked at some examples in other cases and other jurisdictions. I filed some depreciation studies. And I think the big question that comes to mind is, when you look at the experience in other jurisdictions, why is Nova Scotia Power based on its simulated data seeing significantly lower lives than all the other utilities, at least than I have been reviewing, and across many accounts.
>
> And you need to ask yourself, and I’ve asked myself the same question, is there any underlying force of retirement in Nova Scotia Power that is so great that makes it just tough to do business in Nova Scotia for an electric utility, greater forces of retirement that are all negative rather than some that are positive. I can’t come up with any, and that leads

> me to believe that the simulated retirement data that the company's relying upon which is informing the ELG estimates is potentially causing this exacerbated error.
>
> [Transcript, January 12, 2026, pp. 1142-1145]

[210] In this exchange, Mr. Madsen refers to how NS Power's estimated average asset service lives for many accounts, based on its simulated data, are much lower than other peer utilities. This is discussed in more detail in section 3.4.3 of this decision. Nevertheless, a summary of the analysis completed by Mr. Madsen shows NS Power's applied for average service lives are generally lower than those used in New Brunswick, Prince Edward Island and Newfoundland, jurisdictions that are generally subject to similar climate and operating conditions as Nova Scotia.

[211] In his testimony, Mr. Wiedmayer outlined a number of reasons why a peer utility can have survivor characteristics and average service lives that are different than NS Power's. These include differences in capitalization policies, differences in maintenance practices, and differences in the type of structures that are in specific asset accounts. The Board understands these differences but still finds Mr. Madsen's evidence persuasive. Specifically, the Board remains concerned that NS Power's lack of a solid underpinning of true aged data, and related use of simulated data in combination with ELG, is perhaps leading NS Power to arrive at certain conclusions that would not be supported if actual true aged data were present. In particular, the simulated data may be skewing calculations to result in shorter estimated asset service lives, particularly when compared to NS Power's peers. If this is occurring, the use of lower service lives alongside the use of the ELG procedure will result in more aggressive depreciation estimates. In turn, this can lead to intergenerational equity concerns and the need to update depreciation rates more frequently.

[212] NS Power has also submitted that when choosing an appropriate depreciation procedure, the impact on rate base should be a consideration. In their hearing testimony, both Mr. Wiedmayer and Mr. Madsen addressed the interaction between depreciation and return on rate base.

[213] Mr. Wiedmayer testified that while ELG produces higher annual depreciation expense and revenue requirements than ALG in earlier periods, it also reduces rate base more quickly than ALG. Over time this results in lower return on rate base in later periods and a crossover point when depreciation and return on rate base are considered together. For periods beyond this crossover point, the annual revenue requirement under ELG becomes lower than under ALG. In Undertaking U-12 [Exhibit 59(i)], Mr. Wiedmayer filed a copy of an Excel model that he prepared to provide an example demonstrating this crossover point concept between ELG and ALG. The model was created using company-specific (UGI Utilities, Inc.) data. UGI Utilities, Inc. is a combined electric/gas utility with operations in Pennsylvania, Maryland and West Virginia.

[214] Mr. Madsen did not dispute the underlying mechanics described by Mr. Wiedmayer. Under questioning from NS Power counsel, he acknowledged that changes in depreciation expense necessarily affect rate base and related return, and that lower depreciation increases rate base and the return component of revenue requirement. He further acknowledged that collection of lower depreciation expense under ALG would also increase debt costs to finance the rate base differential. Mr. Madsen also confirmed that the analysis presented in his evidence regarding ALG vs. ELG only considered the impact on depreciation expense (i.e., it did not consider the impact on rate base and financing costs). As Mr. Madsen noted, the sole purpose of his testimony is to provide a

recommendation to the Board that "gets depreciation right", recognizing there are going to be other impacts regardless of which depreciation procedure is selected.

[215] Nevertheless, under questioning from the Board, Mr. Madsen provided the following commentary on his analysis of Mr. Wiedmayer's ALG vs. ELG crossover model filed in Exhibit 59(i):

> **MADSEN:** … The more important issues are the fact that the analysis is not based on Nova Scotia Power evidence. When I looked at the more detailed spreadsheet and the USA accounts that were informing the spreadsheet the main USA accounts are 376.1, 376.3, and I could name them, there's six accounts, they're all gas utility accounts. They make up roughly 84 percent of the total asset base, and those are services, gas mains, and things of that sort. They're not electric utility assets akin to what Nova Scotia Power operates. So it's like comparing apples to oranges. And I couldn't, based on my review, actually identify any accounts in this analysis that were electric utility accounts like a tower conductor or even production plant.
>
> The example also assumes a return of 8 percent. A return of 8 percent is not reflective of Nova Scotia Power's weighted average cost of capital, which is somewhere just above 6 percent. A higher return in this analysis is going to dramatically -- quite dramatically overstate the revenue requirement related to this difference that you're seeing in the difference on rate base.
>
> The starting point of the analysis again is for utilities gross plant in service that is not Nova Scotia Power's. If I were to update that starting point to be Nova Scotia Power's gross plant in service of I think roughly eight point something billion dollars and then used the growth rate that I've seen for Nova Scotia Power over the last three years, which has been averaging roughly 3 percent since close to 2024, the rate of growth in that cost increases quite significantly. That's another issue.
>
> The other -- the analysis also ignores income tax sometimes, which can, in several ways, cause the ALG procedure to look like it is creating more revenue than it actually is. Depreciation, when included in revenue, is a taxable item, and the ELG procedure has a higher level of depreciation expense.
>
> I apologize. There's a number of issues. The other issue is the exhibit includes a very, very low composite depreciation rate, somewhere in the range of about 2 percent. While I appreciate that might reflect the gas utility assets that were being studied by Gannett Fleming in this limited example, the applied-for depreciation rate for Nova Scotia Power is somewhere closer to 3.37 percent on a composite basis. So quite a lot higher than 2 percent. When you use that rate, as well as the actual applied-for or recalculated average life group rate, it again materially alters the results of this analysis by changing the amount of depreciation expense calculated.
>
> And I'm almost done.
>
> The composite remaining life is also incorrect in this analysis based on what is the composite remaining life for Nova Scotia Power. So fundamentally the analysis is not a Nova Scotia Power focused analysis and is providing a result that makes -- that is, in my mind, misleading.

> The final point that I would make before I kind of conclude is that the analysis is out over to 2050. Whenever I do an analysis that extends beyond two, to three, to four or five years I do a net present value calculation. So if you look at it on a -- and ignoring the net present value with future cash flows it suggests that based on the two scenarios the ALG procedure will recover $20.3 million more in revenues. Ignoring all of the issues that I just outlined, $20.3 million more revenues than the ELG procedure. But on a net present value basis, using Nova Scotia Power's weighted average cost of capital it is actually unfavourable to the equal life group procedure to the amount of $83.5 million. So it swings by about $100 million the other way. And again if you're looking out into the future at the future impacts that customers are going to pay then you need to analyze that scenario on a net present value basis.
>
> Changing the various variables -- and again my big caveat would be I did not do one of these analysis for the reasons I stated in questioning earlier. It is very difficult to present an analysis like this that is going to be perfectly accurate and reflect the future. If you have -- if you hold several assumptions though true, if you assume a growth rate of 2 percent for Nova Scotia Power, if you assume a weighted average cost of capital of about 6.15 percent, around that range, which reflects the applied-for average cost of capital, and if you assume the growth rate -- or sorry, the depreciation rate in this analysis and change the variables to reflect what Nova Scotia Power actually has invested, there is no crossover point between the ALG and ELG procedures in the next -- between now and 2050. There's not.
>
> If you increase that growth rate to three percent, which again is more closely reflecting the Nova Scotia growth rate in recent years, there will not be a crossover point for a very long time. I don't know when, but it won't be -- certainly well beyond 2050. [Emphasis added]
>
> [Transcript, January 12, 2026, pp. 1171-1176]

[216] In essence, Mr. Madsen does not dispute that over the long-term the total amount of revenue requirement that is collected under ALG will be higher than the total amount of revenue requirement that is collected under ELG, due to increased financing costs. What he does dispute, however, is the timing of when the crossover point happens, as well as the magnitude and relevance of the difference on a net present value (NPV) basis.

[217] The Board recognizes that Mr. Madsen did not complete a formal NPV analysis of Mr. Wiedmayer's ALG vs. ELG crossover model. Nonetheless, the Board finds his related hearing testimony to be convincing. First, even with the model's shortcomings as they relate to the lack of relevant NS Power specifics, the Board notes that the additional $20.3 million collected under ALG would represent only 0.15% of total revenue

collected over the model's 25-year period. So even if the Board were to accept the model as a valid example representing the impact of ALG vs. ELG on NS Power (which it does not), the Board would find this difference immaterial.

[218] The Board agrees with Mr. Wiedmayer that there is a crossover point between ALG and ELG after which the annual revenue requirement under ELG becomes lower than under ALG. However, the Board also agrees with Mr. Madsen that as NS Power continues to grow its rate base (which it certainly intends to do at least over the current GRA test period), depreciation expense will increase to a greater extent than the associated increase in return on rate base. As such, as long as NS Power's rate base continues to grow, the crossover point between ALG and ELG will occur further into the future. The Board does not generally set rates based on long-term convergence of illustrative models. Instead, the Board sets rates on the revenue requirements that customers face in the periods immediately ahead over the test period. Nevertheless, on an NPV basis, the shifting of the crossover point more into the future will further favour the ALG procedure by having a lower NPV of revenue requirements than ELG.

[219] Another issue that the Board considers important when deciding whether it is best to use ELG or ALG is the related impact of each on intergenerational equity. Generally, the selection of a reasonable depreciation expense is heavily dependent on an assessment of intergenerational equities between generations of customers to try and ensure, as best as possible, that the customers who use the assets pay for the assets.

[220] Mr. Wiedmayer addressed intergenerational equity in the context of matching depreciation expense to the pattern of service value consumption reflected in observed retirement dispersion. He acknowledged that ELG and ALG produce different

timing profiles in earlier and later periods. However, he stated that the ELG procedure is designed to allocate depreciation in a manner consistent with the statistical pattern of retirements within a life group, and that doing so promotes equity by aligning cost recovery with the period over which assets provide service. As such, he does not characterize ELG as shifting costs unfairly to current customers. Instead, he noted that ELG distributes depreciation consistent with retirement behavior and accepted depreciation practice, which he views as supporting appropriate cost allocation across customer generations.

[221] Mr. Madsen believes that ELG front-loads depreciation expense relative to ALG, resulting in higher depreciation rates in earlier periods and lower rates in later periods. His primary intergenerational equity concern, therefore, is that it accelerates cost recovery, meaning current customers pay more than they should and future customers pay less. This concern mainly stems from his assertion that ELG's earlier-period expense recognition does not appropriately reflect NS Power's actual consumption of asset service value, which for a number of asset accounts is not based on true aged data. He also noted that as asset lives lengthen over time, which he stated is generally occurring in the electric utility industry, ELG will over-recover depreciation early, creating similar intergenerational equity concerns. Considering the context of the ALG/ELG crossover point, Mr. Madsen also expressed concern that customers paying higher rates in the early years under ELG may not be the same customers who benefit after the crossover. Overall, he argued that the ALG procedure is less aggressive on the front end and provides a more stable depreciation recovery pattern, thereby lessening the risk of intergenerational inequity.

[222] During the hearing, the NS Power depreciation panel raised a further point related to potential intergenerational equity concerns under the ALG procedure. Specifically, the panel noted that under ALG, ratepayers may end up paying for assets that are no longer used and useful. Mr. Madsen acknowledged that this premise could be true, but that it could also occur under ELG when the amount of depreciation expensed does not perfectly reflect the actual consumption of assets over time. He then walked through an example of how this could happen, referencing Figure 17 in his evidence [Exhibit N-34]. Mr. Madsen noted that the distinguishing features between ALG and ELG are that ELG accelerates depreciation in the early years compared to ALG, and then at the other end potentially draws it out for a longer period, although at a much smaller rate.

[223] Based on the discussion above, the Board finds that the ALG procedure produces a more gradual and stable pattern of depreciation expense and related revenue requirement. This, in turn, reduces the risk of intergenerational cost shifting compared to the use of ELG. The Board finds that this is particularly relevant in circumstances where asset service lives are extending over time. The Board believes this is a trend that is occurring in the electric utility industry given technological advances in assets themselves, as well as improving asset management measures undertaken by utilities. Indeed, in recent ACE Plan proceedings, NS Power has touted its asset management plans, procedures and mechanism, the use of which often result in the lives of assets being extended to the benefit of customers.

[224] Overall, the Board believes that the most appropriate depreciation procedure should set asset lives (and related depreciation expense) that best reflect the expected loss of service value of NS Power’s assets over time while minimizing

intergenerational equity risks. The Board also recognizes, however, that no single depreciation procedure will be perfect, and no single procedure can ensure that forecast depreciation expense will be perfectly representative of actual depreciation expense. Further, consistent with the evidence in this proceeding, the Board notes that the advantages of one procedure correspond to the disadvantages of the other. The appropriate choice of depreciation procedure must also, therefore, balance these competing considerations. This effort to achieve an appropriate balance of interests can also be characterized as a matter between present and future customers.

[225] In this context, in assessing the choice between ALG and ELG for NS Power, the Board finds Mr. Madsen's evidence and testimony persuasive. Mr. Madsen acknowledged that both methods are accepted depreciation procedures and recover the same total depreciation over the full-service life of the utility's assets. However, he also identified material differences in timing, sensitivity, and risk between the procedures. He explained that ALG is less sensitive to short-term fluctuations in retirement assumptions and simulated plant data, while the use of ELG for NS Power places greater weight on such data. He also noted the intergenerational equity risks associated with ELG accelerated recovery in earlier periods. Mr. Wiedmayer characterized these effects as neutral timing differences that can be addressed through ongoing depreciation studies.

[226] The Board does not necessarily disagree with Mr. Wiedmayer. However, based on the evidentiary record before it, the Board gives more weight to Mr. Madsen's position that greater sensitivity and front-loaded recovery under ELG increases uncertainty and volatility for NS Power customers, particularly where long-term, true aged plant data is not yet available for a number of NS Power accounts. In these

circumstances, the Board considers ALG to be an approach that better balances accuracy, gradualism, rate stability, depreciation vs return on rate base interactions, and intergenerational equity fairness. Notwithstanding this, the Board is not making a finding that ELG is inappropriate.

[227] The change to the ALG procedure recommended by Mr. Madsen would result in lower rate increases for NS Power ratepayers over the 2026/2027 test period. If all other things remain per the settlement agreement, the change would result in a one-time pre-tax decrease of roughly 1% in average rates. However, the reduction in related depreciation expense resulting from any change to ALG must also be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its FFO:Debt credit metrics even further. This could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[228] Therefore, for the purposes of the current GRA, the Board will not direct NS Power to adjust its depreciation procedure from ELG to ALG. Nevertheless, as noted previously, based on the evidence in the current proceeding, the Board is persuaded that the ALG procedure likely offers a more appropriate means for NS Power to determine depreciation expense. The Board believes this needs to be further considered.

[229] To give some historical context, in April 2003, NS Power filed a depreciation study with the NSUARB that recommended an increase in annual depreciation expense.

A consultation process followed, which culminated in the development of a settlement agreement that was unanimously supported by the intervenors in that proceeding. The settlement agreement on future depreciation rates was adopted as a “black box” settlement. In that type of agreement, parties settled on an amount without fully agreeing to the way the amount was derived. The settlement agreement was approved by the NSUARB in its Decision dated November 21, 2003. Similarly, in November 2010, NS Power filed an updated depreciation study with the NSUARB and requested approval of new depreciation rates. The parties to that proceeding once again reached a “black box” settlement agreement that the NSUARB approved in May 2011.

[230] In both proceedings, the settlement agreements were reached in due course after a full evidentiary record was filed with the Board. Those records included information requests filed by parties, evidence filed by Board Counsel consultants, and, in the 2010 depreciation proceeding, evidence filed by experts retained by intervenors. Specifically in the 2010 depreciation proceeding, the issue of ALG vs. ELG was raised by Board Counsel consultants and the expert hired by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited. Both these experts recommended that NS Power move to using the ALG procedure. However, given the nature of the “black box” settlement agreements in those matters, and the Board’s subsequent approvals, the Board did not opine on the use of ALG vs. ELG in those proceedings.

[231] In the current proceeding, NS Power submitted that it has appropriately applied the ELG procedure for over 30 years. However, as Mr. Wiedmayer acknowledged during the hearing, there is a correlation between NS Power using ELG over this period and the lack of depreciation studies that have been filed by NS Power over the same

timeframe. Further, given the nature of the current GRA settlement agreement approach, the Board is unaware of the extent to which ALG vs. ELG was discussed, or even considered, by the parties to the agreement.

[232] The current GRA is the first time the ALG vs. ELG issue has been put before the Board since the 2010 depreciation study. In addition, the Board's approval of the "black box" settlement agreement in that proceeding did not result in a specific Board finding on whether ALG or ELG was the most appropriate depreciation procedure for NS Power to use moving forward. Nor did the Board's approval of the 2003 depreciation study "black box" settlement agreement result in such a finding. Further, as it relates to NS Power's assets and their related depreciation expense, a lot has changed since 2003. These include such items as legislative changes requiring certain assets to be retired by 2030, technological advancements to improve/extend asset lives, climate change and an evolving NS Power generation asset mix.

[233] Given this background, the Board believes that further testing of ALG vs. ELG, to confirm which methodology is most appropriate for use by NS Power, needs to be addressed as part of the company's next depreciation study. NS Power agreed to this in its reply submissions. Generally, the Board would expect NS Power to file a new depreciation study every five years. However, in this case, the Board believes that waiting five additional years to further examine the use of ALG vs. ELG is too long. As such, the Board directs NS Power to file an updated depreciation study with its next general rate application. The Board believes this earlier study is further warranted by the changing make-up of NS Power's generation assets, as well as its plans to construct significant new transmission assets in the near future. The timing will align more closely with

completion of the IESO Nova Scotia's currently underway IRP. It will also allow NS Power to build up several more years of true aged asset data.

[234] Within the next depreciation study, the Board fully expects that the use of ALG will be more closely examined and assessed in detail by NS Power. As part of its ALG vs. ELG assessment, the Board expects NS Power to address issues including, but not limited to:

- The interaction between depreciation expense and return on rate base;
- The extent to which actual true aged data has been used;
- A NS Power specific ALG vs. ELG cross-over point analysis;
- Comparison to other peer utility data, particularly related to actual age data, the retirement patterns experienced by those utilities, recommended asset service lives, and a description of what forces of retirement those utilities have that are consistent with those of NS Power;
- Identification of specific factors in Nova Scotia that differ from other peer utilities that would lead to a higher rate of retirement or greater forces of retirement;
- The book accumulated depreciation reserve balance and calculated accumulated reserve balance under both the ALG and ELG procedure;
- An evaluation of whether a change to the ALG procedure would violate the principles of gradualism and moderation, and whether a "phasing-in" of ALG would be appropriate; and
- The proposed depreciation by asset account under both ELG and ALG procedures.

3.4.3 Asset Average Service Lives

[235] Section 3.4.1.2 of this decision describes Gannett Fleming's approach to estimating average asset group service lives in its depreciation study. Mr. Madsen described a similar approach in his evidence:

> Both the ALG and ELG procedures rely on the selection of an Iowa curve based on several factors, including but not limited to:
>
> - Visual and mathematical fit of the observed retirement data to the selected survivor curves.
> - Peer data on the average service lives and survivor curves used in other jurisdictions.
> - Discussions with management and operational personnel to understand the life characteristics of the assets and other relevant operating, technical and maintenance details that may impact the lives of the assets.
>
> [Exhibit N-34, p. 59]

[236] As described by Mr. Madsen, when determining a visual fit to a specific Iowa curve, asset account retirement data is reviewed against an Iowa curve to assess how that data fits against the curve relative to alternatives. Visual fitting helps narrow curve types but must consider whether the underlying retirement data is limited or not representative of broader retirement data. Mr. Madsen stated that this is why mathematical curve fitting is also important. Mathematical fitting measures differences between observed retirement data points and the selected Iowa curve to help determine a best fit curve.

[237] Mr. Madsen also stated that peer analysis and comparison is especially important for NS Power, because its data relies heavily on simulated plant data, while peer utilities typically provide actual aged data across similar assets, allowing for a broader and more reliable comparison. As such, he opined that mathematical curve fitting for NS Power should be given less weight, since its reported simulated retirement data

may not reflect true historical patterns, especially where proposed asset lives differ significantly from peers. Finally, Mr. Madsen noted that discussions with company management and operational staff are essential to understand asset life characteristics and to assess whether historical retirement patterns are likely to change in the future.

[238] Mr. Madsen completed a review of Gannett Fleming's recommended asset average service lives for each of NS Power's Plant accounts. For transmission, distribution and general Plant accounts, Mr. Madsen generally followed the process described above. While he did not conduct discussions with NS Power personnel, he did review notes of discussions between company management and Gannett Fleming to help inform his analysis.

[239] Mr. Madsen's peer analysis compared NS Power's proposed average asset service lives to those of the peers used in Gannett Fleming's depreciation study. He also provided a second peer analysis by comparing NS Power's proposed average asset service lives to those noted in recent depreciation studies for NB Power, Maritime Electric (Prince Edward Island), and Newfoundland Power. Except for five Plant accounts, Mr. Madsen's analysis shows that NS Power has applied for average service lives lower than the Gannett Fleming peer average. Similarly, his analysis shows NS Power's proposed average service lives are generally lower than those used in New Brunswick, Prince Edward Island and Newfoundland. Mr. Madsen noted that when lower lives are considered alongside the ELG procedure, the combined result is more aggressive depreciation estimates and lives than are utilized by NS Power's peers.

[240] Based on his curve fitting, peer analysis and management notes review, Mr. Madsen recommended adjustments to the average asset service life and Iowa curve for

several NS Power transmission and distribution Plant accounts. These recommendations are summarized in Table 8 of Mr. Madsen's evidence as follows:

Account Number	Account Name	Investment at Dec 31, 2023	Emrydia Recommended Life Estimate	Emrydia Recommended Curve Estimate
TRANMISSION ASSETS				
353	STATION EQUIPMENT	586,908,962	50	R2.5
354	TOWERS AND FIXTURES	111,028,870	No Change	No Change
355	POLES AND FIXTURES	268,176,042	50	R2.5
356	OVERHEAD CONDUCTORS AND DEVICES	178,454,463	52	R3
DISTRIBUTION ASSETS				
364	POLES, TOWERS AND FIXTURES	646,990,061	45	R1.5
365	OVERHEAD CONDUCTORS AND DEVICES	329,509,672	45	R2
367	UNDERGROUND CONDUCTORS AND DEVICES	75,012,364	No Change	No Change
368	LINE TRANSFORMERS	555,455,934	36	R1
GENERAL PLANT ASSETS				
390.1	STRUCTURES AND IMPROVEMENTS	184,609,960	No Change	No Change

[Exhibit N-34, p. 73]

[241] For NS Power's production Plant accounts, Mr. Madsen conducted a slightly different review process, as NS Power's IRP served as the formative document related to production Plant service lives. For this review, Mr. Madsen reviewed the detailed assumptions and Iowa curves proposed by Gannett Fleming, reviewed the IRP and related materials to confirm the life span dates align with the most recent planning information, and reviewed the information obtained by Gannett Fleming from management to support its decisions.

[242] Based on his review, Mr. Madsen did have some concerns about the proposed retirement dates for some of NS Power's production Plant. Nevertheless, he did not recommend any changes to the proposed service lives. In reaching this conclusion, he was mindful of the other depreciation related changes he recommended. He also noted the risks associated with NS Power's forward-looking generation forecast, including the use of small modular reactors, significant reliance on wind and batteries, and other considerations. As such, he suggested that a wait and see approach through

to the next depreciation study and the next IRP would be a more pragmatic approach to addressing production Plant service lives.

3.4.3.1 Findings

[243] In Undertaking U-8, NS Power provided calculations showing the dollar effect of implementing the changes recommended in Table 8 of Mr. Madsen's evidence. NS Power performed the analysis using both the ALG and ELG depreciation procedures. The ALG calculations show a reduction in depreciation expenses (as compared to NS Power's GRA filing) of $25.7 million and $27.3 million in 2026 and 2027, respectively. The ELG calculations show a reduction of $6.1 million in 2026 and $6.5 million in 2027.

[244] The ALG calculations show a significant decrease in depreciation expense if Mr. Madsen's average service life recommendations are approved in combination with NS Power switching to the ALG depreciation procedure. These reductions would result in lower average rate increases for NS Power customers over the 2026 and 2027 test period (although they would be offset partially by the related increase in return on rate base). However, the ALG calculations are moot at this point, given the Board's findings elsewhere in this decision that it will not require NS Power to switch to ALG for the 2026/2027 test period.

[245] The ELG calculations also show a decrease in depreciation expense if Mr. Madsen's average service life recommendations are approved. These reductions too would result in lower average rate increases for NS Power customers over the 2026 and 2027 test period (although they would also be offset partially by the related increase in return on rate base). The issue for the Board to decide is whether Mr. Madsen's recommendations are warranted.

[246] During the hearing, Mr. Wiedmayer was questioned about the average service life changes recommended by Mr. Madsen:

> **MEMBER MURPHY:** This is my last question. It's related to asset service lives and retirement dates. And in Mr. Madsen's evidence he referenced a number of your curves, I suppose, and how they fit with the data, the actual retirement data. And there was one in particular where it was related to transmission poles and fixtures, and Mr. Madsen had recommended a 50-R2.5 curve, and you have a 45-R1.5. And when you look at the curve -- I could call it up. When you look at the curve Mr. Madsen suggests that beyond year 30.5 the data doesn't fit very well, and that's part of the reason I think why he's suggesting a different curve. I can call the curve up if you want. But it does look like ---
>
> **A.** (Wiedmayer) Yes, I would like to see that, because that is a good example of one that I think we should look at.
>
> **Q.** Okay. It's -- Jeff, it's Exhibit N-34, PDF page 83.
>
> **MEMBER MURPHY:** And Mr. Madsen made the same comment, Mr. Wiedmayer, this particular curve is just for transmission poles and fixtures, but he also made similar comments related to some of the other asset groups where the curves that you suggested don't fit that well.
>
> In this particular case when I look at the curve it does look to me that it's not a great fit after year 30 or so. So my question was, you know, in this particular case, why do you think that 45-R1.5 is better than the one that Mr. Madsen suggested?
>
> **A.** (Wiedmayer) Okay. Yeah, so here's a really good example, in the sense that the historical data is represented by those squares, black squares on the chart. So Nova Scotia's historical retirement experience indicates, when I look at this chart -- I know not everybody in the room is a depreciation expert, but what it indicates to me that the 45-year average service life indicated by that smooth black line is above or to the right of the black squares. So really the best fit IOWA types or R curve for this account probably is more like a 41- or a 42-year average service life from a historical basis.
>
> So I had in the previous study recommended a 47-year average service life. However, Nova Scotia with, I think, tropical storms becoming more and more prevalent and some other reasons for earlier retirements, your actual retirement experience is indicating shorter lives than what I have proposed. Mr. Madsen's 50-year average service life would be even further above and to the right of my 45-R-1.5. So Mr. Madsen's 50-year recommendation is based, I would suspect, purely on industry data and judgment and not based on the company's actual retirement experience, which is a shorter life -- an even shorter life than what I've recommended.
>
> **Q.** So in your opinion I guess, from what I'm hearing, the curves that are recommended by -- in this particular case anyway, the curve recommended by Mr. Madsen would be even a worse fit to that actual data; correct?
>
> **A.** (Wiedmayer) Correct. That's exactly correct, yes.
>
> [Transcript, January 7, 2026, pp. 323-326]

[247] Mr. Madsen responded to the points raised in this exchange during his own hearing testimony:

> **BY MEMBER MURPHY: …**this is the curve that I walked through with Mr. Wiedmayer the other day, and this is for account 355. And Nova Scotia Power is recommending using the Iowa 45-R1.5 curve, and I think you were recommending the — I think it was the R50.
>
> …
>
> **A.** (Madsen) Fifty (50)-R2.5.
>
> **Q.** That's right, yeah. And when I asked Mr. Wiedmayer about this, he indicated that [if] the Iowa 50-R2.5 curve was used here, it would be further to the right than the curve you suggested, or the curve that Nova Scotia Power suggested, and that would seem to indicate that the curve you recommended is a worse fit to that, I guess, simulated data, those squares, than Gannett Fleming had recommended. I'm just wondering if you have any comment on that.
>
> **A.** (Madsen) Yes. So he is correct. The curve that I recommend would have a worse fit to the retirement data. Again, this is simulated retirement data. And it would not represent the actual retirement data that would be present for Nova Scotia Power had it had that historical information.
>
> I think if it's — it may not be helpful, but if you look at some of the other reports, Mr. Murphy, that I filed, for example Newfoundland Power, and the similar data for this account where there is actual aged data, not simulated age data, you see that there is a very different trend in the aged data relative to what is shown here on a simulated basis.
>
> And that is why when I recommended the curve that I did, I recommended a curve with a longer life, which does not fit this aged data as well, because I can't devise a reason why Nova Scotia Power would have retirements for account 355, which is poles and fixtures, which would suggest a life of 40 to 41 years, and I think that's what Mr. Wiedmayer confirmed as well. And when I modelled it, I figure — I noted that best-fit curve would be similar along a 41-R1 curve to that data.
>
> A 41-year life for this account would be well below the range of peers, well below what I have seen in other jurisdictions. And if I were to simply rely on the simulated data, again keeping my simulated data, and run a conclusion, the conclusion that that is the best curve to select, then I think that would result in a recommendation that is incorrect, and that's why I did not recommend it.
>
> **Q.** Okay. The other curves you recommended for the other accounts, if I look at them all in general, they would all tend to fall to the right of the curves that Gannett Fleming had recommended. So I guess if I was to ask you the same question about all those other accounts I would get the same answer; correct?
>
> **A.** (Madsen) Same answer, sir. Maybe it would be helpful if we had before us actual retirement data, and I describe this is in my report. If this curve that we were looking at was actual retirement data, I'd probably be asking myself why Gannett Fleming did not recommend a 41-R1 curve, and I would probably start with recommending a 41-R1 curve because that would best reflect the actual retirement data for Nova Scotia Power. We're not looking at actual retirement data, which is why I need to assign the weight to the simulated data that I can, and in my opinion, I would not assign significant weight.

> Now again, if the simulated data was showing that — the best guess was showing that for this account Nova Scotia Power was dead set right in the middle of its — the recommended peer range, say somewhere around 50 years, and management's notes suggested that that was consistent with their expectations of the life of the asset, I would likely be again recommending that the simulated data provided more weight because it is consistent with the other data that I have reviewed. In this case, it's just so inconsistent it's hard to assign significant weight to it. [Emphasis added]
>
> [Transcript, January 12, 2026, pp. 1153-1157]

[248] There are two primary arguments that Mr. Madsen is making for his recommended changes to NS Power's average asset service lives. First, he argues that NS Power's use of simulated aged data would not represent actual NS Power retirement data if the company had that historical information. And second, he asserts that the average service lives put forward by NS Power are materially lower and inexplicably different than its peer utilities, particularly other Atlantic Canadian utilities.

[249] Throughout his hearing testimony, Mr. Wiedmayer discussed his use of peer utility comparisons as more of a reasonableness check. He uses such comparisons to make sure his estimates for average asset service lives are within the bounds used by other utilities. He noted, however, that he does not use these comparisons as a substitute for a company's actual historical asset retirement experience. If a reasonableness check shows significant differences between his recommended service lives and the bounds of other peer utilities, he would then review the material once again with utility staff to determine the reasons why and if adjustments are required. He also noted that each electric utility has its own unique survivor characteristics due to a variety of reasons, including differences in capitalization policies, differences in maintenance practices, and differences in the type of structures that are in specific asset accounts.

[250] During hearing questioning from Board Counsel, Mr. Wiedmayer also took issue with Mr. Madsen's argument about NS Power's use of simulated aged data. Mr.

Wiedmayer pointed out that he did, in fact, use actual data for NS Power, but that the retirements were not aged. Specifically, he used actual data about when assets were installed but did not know when the related retirements occurred. Then, based on the addition and retirement pattern, simulation was used to place a reasonable age on the retirements that did occur.

[251] In general, the Board agrees with NS Power in its closing submissions that calculation of depreciation rates requires professional judgement and experts can have differing opinions on the appropriate survivor curves and service lives. The Board also finds that Mr. Wiedmayer's arguments about the use of simulated data and checks against peer utilities are reasonable. However, the Board finds Mr. Madsen's evidence to be more compelling, particularly as it relates to many of NS Power's average asset service lives being much lower than those of its Atlantic Canadian peer utilities. Therefore, for the purposes of the current GRA, the Board finds that the average asset services lives recommended by Mr. Madsen for the accounts noted in Table 8 of Mr. Madsen's evidence are more reasonable than those put forward by NS Power. Nonetheless, for the reasons that follow, the Board will not direct NS Power to make the related changes to its GRA.

[252] The average service life changes recommended by Mr. Madsen would result in slightly lower average rate increases for NS Power ratepayers over the 2026/2027 test period. However, the reduction in related depreciation expense must also be considered in the context of the status of NS Power's intended securitization of assets within the scope of the DDA. With securitization remaining uncertain, as explained later in this decision, a change in NS Power's proposed depreciation expense from what is proposed in the application would affect its FFO:Debt credit metrics even further. This

could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[253] Therefore, the Board accepts the average asset services lives as presented by NS Power in the settlement agreement. As such, for the purposes of the current GRA, the Board will not direct NS Power to adjust the average service lives of the accounts recommended by Mr. Madsen.

[254] This notwithstanding, Mr. Madsen made some other recommendations related to those accounts. These recommendations include:

- Account 354 – Towers and Fixtures: NS Power should track the nature of additions to this account going forward, and to the extent practicable, break out the historical cost of new towers within the account. This information should be provided as part of NS Power's next depreciation study.
- Account 356 – Overhead Conductors and Devices: NS Power should better study the physical lives of the assets in this account and describe in detail the types of assets installed by type, quantity, and estimated age. NS Power should also segregate its overhead conductor in Account 356 into the conductor that is strung on higher dollar value steel towers with longer lives and provide NS Power's estimate of the service lives of that conductor with explanations. This information should be provided as part of NS Power's next depreciation study.
- Account 367 – Underground Conductors and Devices: In its next depreciation study, NS Power should explain the proposed life and why that life is appropriate considering NS Power's facts and circumstances.

- Account 390.10 – Structures and Improvements: For each major structure in this account, NS Power should disclose the expected useful lives of the assets, the date the asset was acquired or constructed, and identify when NS Power expects to retire each asset. This data will provide further information to better understand the likely average service life of these assets. This information should be provided as part of NS Power's next depreciation study.

The Board believes that these recommendations would be useful moving forward. Therefore, the Board directs NS Power to address each of these recommendations in its next depreciation study filed with the Board.

[255] Mr. Madsen also recommended that the Board direct NS Power to provide at minimum the following information in support of both production Plant and mass property as part of its next depreciation study, rather than wait for that information to be requested through the information request process:

- Detailed management notes for each account;
- All analysis and studies performed by management for each asset to confirm the expected life;
- All updated IRP documents;
- A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and
- The peer analysis relied upon by the company in an Excel file.

The Board agrees with Mr. Madsen's recommendations. Further, during the hearing, NS Power witnesses agreed that providing this information would be reasonable. Therefore,

the Board directs NS Power to include this information in its next depreciation study filed with the Board.

3.4.4 Amortization Accounting for General Plant Assets

[256] NS Power has proposed the use of amortization accounting for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Amortization accounting is typically employed for accounts with a smaller investment balance relative to larger accounts, and where there are numerous assets without distinguishable life characteristics, such as laptops.

[257] In amortization accounting, the cost of an asset is allocated over a decided time frame, typically a period consistent with its expected service life. The asset is retired and removed from the accounting books once it has been fully amortized, regardless of whether it is rendering service.

[258] The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in the NS Power depreciation study are based on Gannett Fleming's judgement, which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

[259] NS Power has proposed the use of amortization accounting for the following General Plant accounts:

- Account 391.10 Furniture and Equipment (20-year amortization period),

- Account 391.31 Computer Equipment – Hardware (5-year amortization period),
- Account 391.32 Computer Software (10-year amortization period),
- Account 394.00 Shop Equipment (20-year amortization period), and
- Account 398.00 Miscellaneous Equipment (20-year amortization period).

[260] In response to NSEB IR-83, NS Power stated that many electric utilities in North America have received regulatory approval to adopt amortization accounting for these groups within general plant. Examples include Newfoundland Power, BC Hydro, Centra Gas Alberta Inc., UGI Utilities Inc. – Electric Division, and West Penn Power Co. The United States Federal Energy Regulatory Commission (FERC) through its Accounting Release 15 has also accepted the use of amortization accounting for these groups. Mr. Madsen also noted that the use of amortization accounting for such accounts is common for utilities.

[261] Amortization accounting for these General Plant accounts would require NS Power to retire vintaged asset balances that are assumed to be fully depreciated as determined in the depreciation study. The lower depreciation as a result of these retirements would be offset by a reserve imbalance amortization charge. A reserve imbalance is caused by Plant and reserve activity that is different than what depreciation models forecasted. It is calculated as the difference between the book reserve and the theoretical reserve for an asset. The theoretical reserve is the amount that should have been collected based on the age of the asset and the selected amortization related to these five General Plant accounts. The theoretical reserve is used as a benchmark to assess the adequacy of the NS Power's book reserve. Any difference between the two is trued up prospectively over a reasonable amortization period. Per Gannett Fleming's

recommendation, NS Power intends to amortize the reserve imbalance over a 5-year period using whole life amortization rates.

3.4.4.1 Findings

[262] In its GRA, NS Power stated that the estimated impact of adopting amortization accounting would result in annual incremental depreciation expense of $600,000 over the test years. This is primarily related to the implementation of shorter amortization periods for some assets.

[263] The Board notes that the asset groups NS Power has proposed be subject to amortization accounting consist of numerous units of property, often of modest original individual cost, particularly when compared with units in other asset groups. Property of this type tends to have a relatively short useful life. Over time, as the reserve imbalance is trued-up, the use of amortization accounting for these accounts should result in much less accounting effort to track these numerous, low unit-cost assets. This will result in lower administrative overhead costs without any material reduction in accounting accuracy. As such, the Board agrees with NS Power that the proposed amortization accounting for these accounts is a cost-effective way to manage cost recovery.

[264] The Board, therefore, approves the use of amortization accounting for the five General Plant accounts as proposed.

3.4.5 Submissions of the Nova Scotia Department of Energy

[265] The Department of Energy presented the following on page 6 its closing submissions:

> 30. The copy of the Gannet Fleming depreciation study as of December 31, 2023, does not contain any reference to the words “stranded,” “useful life,” “government” or “legislation,” which suggests that none of these factors were considered in determining appropriate depreciation. In fact, the following is an excerpt from a summary of the year in service, probable retirement year and life span for each power production facility taken from the Report:

A summary of the year in service, probable retirement year and life span for each power production facility follows:

Depreciable Group	Nameplate Capacity Rating, MW	Year in Service	Probable Retirement Year	Life Span
Steam Production Plant				
Lingan Units 1	150.5	1980	2049	69
Lingan Units 2	150.5	1981	2029	48
Lingan Units 3-4	150.5	1984	2049	65
Point Aconi	165.0	1994	2029	35
Point Tupper	150.0	1973	2048	75
Trenton 5	150.0	1970	2029	59
Trenton 6	160.0	1992	2029	37
Tufts Cove 1	100.0	1966	2049	83
Tufts Cove 2	100.0	1973	2049	76
Tufts Cove 3	150.0	1977	2049	72
Tufts Cove 6	50.0	2011	2049	38

31. The Department asks that the Board review the “Probable Retirement Year” column whilst considering existing legislation and government policy.

[266] The Board has reviewed the “Probable Retirement Year” column and finds it is acceptable and consistent with retirement dates noted in the company’s most recent 10-Year System Outlook Report. In particular, Lingan 1, 3 and 4 are currently scheduled to be converted from coal-fired to heavy fuel oil fired in 2029. Similarly, Point Tupper is scheduled to be converted from coal-fired to natural gas-fired in 2029. As such, these facilities will meet existing legislation mandating that NS Power be off coal by 2030.

[267] The Department of Energy also submitted that NS Power’s failure to diligently file updated depreciation studies may have resulted in excessive returns to the utility. The Department of Energy contends that had NS Power prepared timely, updated depreciation studies, NS Power’s overall allowable returns would likely have been reduced, resulting in lower rates for ratepayers. The Board notes that the Department of Energy’s contention would only be true if the updated depreciation studies resulted in higher depreciation rates. Further, if that was the case, this does not necessarily mean that lower overall rates would result for ratepayers. As explained previously in this

decision, higher depreciation rates result in higher rates for ratepayers which are offset by some degree by lower return on rate base.

3.4.6 Depreciation – Summary

[268] For the purposes of the current GRA, the Board finds it appropriate to exclude decommissioning costs for the Wreck Cove, Mersey, and Tusket hydro systems from proposed depreciation rates for the 2026 and 2027 test years. The Board directs NS Power to provide, in its next depreciation study, a reconciliation (from 2009 onward) of annual interim and final net salvage collections and actual salvage costs for these hydro assets.

[269] For the purposes of the current GRA, the Board accepts the inclusion of partial decommissioning costs of NS Power's other hydro Plant assets in depreciation rates for the test years. Nonetheless, the Board agrees with NS Power that no settled policy or multi-stakeholder framework currently exists to determine whether, when, or how partial or full decommissioning costs for hydro Plant should be included in depreciation rates. Similarly, no such policy or framework currently exists to identify who should bear on-going costs associated with partially decommissioned hydro assets that are no longer used and useful. As such, the Board directs NS Power to initiate a structured engagement process involving regulators, government, and other relevant parties to address this issue, with an ideal target completion in advance of NS Power's next GRA. During this process, the Board directs NS Power to file regular update reports with the Board once every six months, beginning October 1, 2026.

[270] The Board finds that the majority of the proposed net salvage rates in the settlement agreement fall within a reasonable range. The Board, therefore, approves the net salvage rates for Plant accounts not subject to settlement agreement adjustments

and for the three transmission and distribution Plant accounts which are subject to settlement agreement adjustments.

[271] The Board has intergenerational equity concerns though with the settlement agreement adjustments affecting production Plant net salvage rates, which recovers the expected future costs to salvage and remove/decommission these assets, including any salvage proceeds. Generally, the Board would be inclined to not approve these adjustments even though this would result in a slight increase in average customer rates in the current GRA. However, at this point there remains considerable uncertainty related to current decommissioning cost estimates for these assets. This is particularly true for NS Power's hydro assets, where it remains uncertain whether these assets will eventually undergo partial or full decommissioning, or even be decommissioned at all. As noted above, the Board has directed NS Power to address this issue before its next GRA. Given this uncertainty, the potential impact, if any, of assumed production Plant net salvage rates on future ratepayers is unclear. In this circumstance, the Board accepts the proposed settlement agreement adjustments to net salvage rates for NS Power's production plant accounts. Therefore, for the purposes of the current GRA, the Board also approves the settlement agreement adjustments to net salvage rates for NS Power's production plant accounts.

[272] The Board also finds that the use of the ALG depreciation procedure likely represents a more reasonable, equitable and prudent depreciation framework than continued use of ELG by NS Power. The Board further finds that the average asset services lives recommended by Mr. Madsen for the accounts noted in Table 8 of his evidence are more reasonable than those put forward by NS Power. Generally, the Board

would be inclined to direct these changes, which would result in a decrease in average customer rates in the current GRA.

[273] If the Board were to direct NS Power to change to the ALG depreciation procedure and to adopt the asset service life changes recommended by Mr. Madsen, NS Power's depreciation rates in the GRA test period would be reduced by roughly $45 million. This would equate to a one-time pre-tax decrease in average customer rates of approximately 2%. However, downward adjustments to NS Power's depreciation expense included in revenue requirement would have the effect of decreasing the company's cash flow. It would also reduce recovery of capital investment thereby increasing debt. These factors would negatively impact NS Power's FFO:Debt credit metrics.

[274] In Undertaking U-7, NS Power provided estimates of forecast FFO:Debt credit metrics under both the ALG and ELG depreciation procedures with and without the settlement agreement adjustments, and under the assumption that securitization of the assets within the scope of the DDA proceeds. These estimates show that under the ELG methodology with the settlement agreement adjustments, the FFO:Debt metric will be 12.1% to 12.3% in 2026 and 12.7% to 12.8% in 2027. Under ALG with the settlement agreement adjustments, the metric estimates range from 10.9% to 11.1% in 2026 and 11.4% to 11.5% in 2027. So, if the Board were to direct NS Power to use the ALG procedure, NS Power's FFO:Debt credit metric would be reduced by roughly 1.2%. Again, this is under the assumption that securitization of the assets within the scope of the DDA proceeds.

[275] In response to NSEB IR-122, NS Power indicated that if its GRA application is approved by the Board and if securitization of the assets within the scope of the DDA does not proceed, its FFO:Debt credit metric would be 10.7% in 2026 and 11.1% to 11.2% in 2027. Therefore, if the Board directs NS Power to use the ALG depreciation procedure, and securitization of the assets within the scope of the DDA does not procced, the company's credit metric would fall below 10% in both 2026 and 2027. If the Board were to further direct NS Power to make the asset service life adjustments recommended by Mr. Madsen, these metrics would degrade further but only nominally.

[276] As Pelino Colaiacovo of Morrison Park noted is his testimony, credit metrics at this level would be problematic. This could increase the risk of having the credit rating agencies lower NS Power's credit rating to "junk" status. As noted in Morrison Park's evidence, this would have serious long-term cost consequences resulting in higher costs for ratepayers.

[277] The service life and ALG changes the Board has considered would result in lower rates for customers over the test period. Nevertheless, in the Board's opinion, the increased credit rating risk related to these changes coupled with the uncertainty of securitization of the assets within the scope of the DDA not proceeding (as indicated in the Department of Energy's closing submissions), would more than offset the benefit of the depreciation related changes considered by the Board. As noted by Morrison Park:

> A downgrade of NSPI's credit rating would have serious long-term consequences, as the company would no longer be investment grade. All new issuances of debt would be significantly more expensive than was historically the case. Immediate consequences would likely include lack of access to the commercial paper market, and the breaching of covenants in project agreements with partners like the CIB. These consequences go beyond the monetary in nature.
>
> [Exhibit N-36, p. 26]

[278] Therefore, for the purposes of the current GRA, the Board will not direct NS Power to use the ALG depreciation procedure for the current GRA. This notwithstanding, the Board directs NS Power to file an updated depreciation study with its next general rate application. The Board expects that this depreciation study will address, but not be limited to, the following issues:

- Depreciation expense and rate base interaction;
- Extent of true aged data use;
- A NS Power specific ALG vs. ELG crossover analysis;
- Peer utility comparisons;
- Analysis of forces of retirement unique to Nova Scotia;
- Accumulated depreciation reserve deficiency impacts under both methods;
- Whether a phased-in transition to ALG would be appropriate; and
- Proposed depreciation rates by asset accounts under both ELG and ALG procedures.

[279] Moreover, for the purposes of the current GRA, the Board approves the asset service lives presented in NS Power's application, including the settlement agreement adjustments made to service lives for Accounts 353 and 390.10. The Board directs NS Power to address Mr. Madsen's recommendations related to asset Accounts 354, 356, 367 and 390.10 in its next depreciation study filed with the Board, NS Power is also directed to provide the following information in its next depreciation study filed with the Board:

- Detailed management notes for each account;
- All analysis and studies performed by management for each asset to confirm the expected life;
- All updated IRP documents;

- A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and
- The peer analysis relied upon by the company in an Excel file.

[280] The Board approves the use of amortization accounting for the following five General Plant accounts:

- Account 391.10 Furniture and Equipment (20-year amortization period);
- Account 391.31 Computer Equipment – Hardware (5-year amortization period);
- Account 391.32 Computer Software (10-year amortization period);
- Account 394.00 Shop Equipment (20-year amortization period); and
- Account 398.00 Miscellaneous Equipment (20-year amortization period).

3.5 Regulatory Deferrals

3.5.1 Securitization Deferral

3.5.1.1 Background

[281] Securitization was described by NS Power as the “centrepiece” of its general rate application and the settlement agreement. The practical impact of securitization in this matter is that it would result in ratepayers paying a lower financing rate on retiring certain utility coal plant and related assets as required under federal and provincial decarbonization policies. In its application, NS Power estimated that securitization could save customers about $90 million over the 2026 and 2027 period.

[282] Securitization is a complex commercial transaction which removes assets from a utility’s balance sheet and restructures the assets into debt, which is then refinanced in a bond issuance or other type of securities offered to investors in the debt markets. The purpose of securitization is to obtain the highest possible credit rating so

that the bond issuance can attract a materially lower interest rate than the return on rate base otherwise paid to the utility by ratepayers on those assets. Since the utility should be able to reduce the financing costs for the securitized assets, ratepayers will be able to pay lower financing costs over the term of the amortization period. After the securitization, the utility's shareholders no longer earn a return on the assets. Further, since the debt associated with the assets has been removed from the balance sheet, the securitization results in improved credit metrics for the utility.

[283] There are a few steps to implement a securitization. First, there must be legislation in effect authorizing a securitization process for the assets, including the issuance of a financing order by the regulator and the creation of a charge or pledge that will provide bondholders an irrevocable right to receive the bond principal and interest from ratepayers to retire the securitized debt. This is important so that the debt can attract the highest possible credit rating to obtain the lowest interest rates.

[284] Second, the regulator must issue a financing order authorizing the securitization to proceed on the identified assets. The financing order typically confirms the irrevocable nature of the charge to be paid by ratepayers. The order may also direct a true-up mechanism to adjust the charge to ensure the coverage of the principal and interest if energy sales vary from forecast. As noted in prior matters, complex commercial transactions involving the corporate structure of the utility may also be required to implement the securitization and isolate the securitized debt for the benefit of bondholders, usually through a special purpose entity. In the case of NS Power, this involves dealing with corporate items such as trust indenture and debt covenant-related

issues, together with the assessment of credit rating agency treatment and income tax treatment of the amounts to be securitized (see 2024 NSUARB 67, M11220, para. 105).

[285] NS Power intends to request approval of the securitization of $704 million of the unrecovered net book value of thermal assets within the scope of the Decarbonization Deferral Account ($500 million in 2025 and $204 million in 2026). However, since legislation has yet to be enacted in Nova Scotia to authorize securitization, NS Power requested the Board's approval of a "securitization deferral" in the event securitization was delayed and could not be completed by January 1, 2026. For this deferral, the depreciation expense and financing costs of these assets intended to be securitized on January 1, 2026, would be deferred at WACC on an interim basis until securitization is in place. The intent is to add the deferred depreciation and financing costs to the amount to be securitized. The issue to be addressed in this application is whether this deferral account should be approved. NS Power will seek Board approval of the securitization in a subsequent application, should it proceed.

[286] Securitization by utilities is more prevalent in the United States. The present case may be the first example of this mechanism being proposed by an investor-owned regulated utility in Canada. A form of securitization was applied in Ontario a few years ago for Ontario Power Generation, a Crown-owned utility.

[287] A successful securitization should reduce costs for ratepayers. For example, instead of paying NS Power's weighted average cost of capital on a deferral account (which is currently set at 6.65% for 2025), ratepayers would potentially pay a lower interest rate on a bond issuance authorized under a financing order. NS Power estimated the interest rate that could be achieved in a bond issuance at about 5%, based

on market conditions forecast in November 2025 (see Morrison Park IR-7). The result of the above is that NS Power would no longer earn a return on the securitized assets.

[288] Securitization has been raised over the past several years in proceedings involving NS Power, with the Board and intervenors urging NS Power to investigate this option as a means to mitigate rate impacts on ratepayers. A similar mechanism was used to address a significant FAM balance owed by ratepayers, and more recently in matters leading to the present application about the costs associated with the retirement of coal plants. As noted by counsel for the Municipal Electric Utilities of Nova Scotia (MEUs), NS Power appeared reluctant to pursue securitization until recently:

> It is worth noting that NS Power was initially opposed to securitization. In a May 3, 2022 response to questions in its 2022-2024 General Rate Application ("GRA"), NS Power stated: "…there are other factors which make securitization not the preferred approach for NS Power at this time."
>
> The Settlement Agreement in the 2022-2024 GRA included an agreement in principle to the DDA to recover undepreciated thermal asset NBV and unrecovered decommissioning costs. Although the Board's decision in the 2022-2024 GRA identified several items to be addressed in the subsequent filing, including potential use of securitization, NS Power's June 30, 2023 application for the DDA in Matter M11220 proposed deferring any investigation of securitization. Intervenors noted NS Power reiterated securitization was not its preferred mechanism and did not conduct any form of economic analysis to assess the cost or benefit of securitization compared to financing at NS Power's Weighted Average Cost of Capital ("WACC").
>
> At para. 111 of its April 10, 2024 decision approving the DDA in that matter, the Board agreed that NS Power was non-responsive on the issue of securitization and endorsed the intervenor comments. The Board directed a meaningful investigation of the potential use of securitization with a report due no later than April 30, 2025.
>
> [MEUs Closing Submission, January 30, 2026, p. 4]

[289] As is the case in other jurisdictions, securitization must be authorized by legislation before it can be implemented. In its final report in February 2024, the Nova Scotia Clean Electricity Solutions Task Force recommended that new legislative provisions allow the Board to have "a complete suite of tools to ensure lowest cost for utility customers in dealing with the financial consequences of the early retirement of

NSPI's coal fired facilities" (p. 46), referring to securitization, among other mechanisms. The Province accepted this recommendation and amended the *Public Utilities Act* in April 2024 to introduce a provision allowing the Board to issue a financing order authorizing a securitization: *Energy Reform (2024) Act*, SNS 2024, c 2, s 72:

> **35G (1)** The Energy Board and the Regulatory Board may approve, deny or modify an application for a financing order.
>
> **(2)** The Governor in Council may make regulations respecting all aspects of financing orders, including defining financing orders and when they may be used.
>
> **(3)** The exercise by the Governor in Council of the authority contained in subsection (2) is a regulation within the meaning of the Regulations Act.

[290] However, to date, s. 35G has not been proclaimed and no regulations have been enacted to implement the securitization process.

3.5.1.2 Present Application

[291] In this application, NS Power indicated its future intent to ask for the securitization of $704 million of the unrecovered net book value of thermal assets within the scope of the DDA ($500 million in 2025 and $204 million in 2026). At the time of its application in September 2025, it submitted that securitization would save ratepayers $90 million in the 2026-2027 test period. Later, in response to an IR from Morrison Park in November 2025, NS Power updated its forecast and the savings at that time were estimated at about $85 million over the 2026-2027 test period.

[292] However, the current application does not ask for Board approval of securitization. In its September 2025 general rate application, NS Power stated that if the securitization could not be completed by January 1, 2026, it requested the Board, in the interim, approve a "securitization deferral" to defer at WACC the depreciation expense and financing costs of the unrecovered net book value of the thermal plant assets within

the scope of the DDA, until securitization can move forward. The assets sought to be securitized would be the thermal assets related to Point Aconi, Trenton, the Point Tupper Marine Terminal, the Sydney International Coal Pier, and steam general assets. NS Power also proposes to add the deferred depreciation and financing costs accrued in the deferral account to the securitization amount. It said at the January 2026 hearing that the Province had not yet proclaimed the legislation to allow the securitization to proceed and confirmed its request for the securitization deferral.

[293] NS Power also noted in its application that it had to address some preliminary corporate items in advance of the securitization:

> … No Canadian investor-owned utility has undertaken a securitization similar to those undertaken by United States investor-owned utilities. As such, it is anticipated that a NS Power securitization will require identifying a finance structure to resolve a variety of issues including, but not limited to, credit rating, trust indenture and tax considerations. Subject to successful credit rating agency processes and the issuance of enabling regulations, NS Power intends to apply to the NSEB for approval for the securitization of approximately $700 million of DDA assets over the GRA period.
>
> [Exhibit N-3, p. 52]

[294] The settlement agreement contemplated NS Power applying to the Board for the proposed securitization, stating that “NS Power will make best efforts to finalize and apply prior to January 1, 2026, for approval of its proposed securitization of assets, cost-of-service treatment and the Securitization Rider”. It was also agreed among the parties that they could take any position they choose about such an application. Given that the parties agreed to NS Power applying for the securitization and reiterated that support in their closing submissions, the Board infers that the customer representatives reserved the opportunity to comment on cost-of-service issues, the form or operation of the rate recovery rider, etc. However, the requested securitization deferral itself was not canvassed in the settlement agreement, as NS Power acknowledged to the Small

Business Advocate in cross-examination (Transcript, January 7, 2026, p. 209, lines 11-13).

[295] Morrison Park reviewed the general rate application in the context of the company's credit rating issues and the proposed securitization. With respect to the latter, Morrison Park confirmed that securitization would help the utility in improving its credit metrics. Specifically, Morrison Park stated that in the absence of both securitization and its requested rate increase, NS Power would be unable to meet its credit metrics thresholds and its credit rating would be seriously jeopardized. Morrison Park noted that NS Power had suffered a credit rating downgrade in November 2022 to BBB-, which is the lowest investment grade status and just one level above “junk bond” status. Morrison Park cautioned that the Board needs to be mindful of the risk of the utility dropping to “junk bond” status. It said a further downgrade would have “potentially significant consequences”, noting the importance of NS Power maintaining a minimum target of 10% FFO:Debt, that being a key credit metric monitored by credit rating agencies.

[296] Morrison Park noted that matters impacting NS Power’s credit ratings can result in higher borrowing costs. It described the circumstances which occurred in late 2022:

> In November of 2022, NSPI’s rating was downgraded by two notches by S&P, to BBB-, a rating which it continues to have today. As reported by NSPI in the application, this places NSPI in the bottom 10% of utilities in North America. The vast majority of utilities have credit ratings of BBB+ or higher.
>
> In the November 21, 2022 Research Update in which S&P reported on the downgrade of NSPI’s rating, the primary cause of the ratings action was described as the enactment by the province of Nova Scotia of Bill 212, which would override the authority of the then-NSUARB, and limit the increase in electricity rates by fiat. This was described by S&P as a “political intervention” in the independence of the regulator, and caused the downgrading of the business risk profile of the utility to “strong” from “excellent”. Many other factors were addressed, but the overriding issue of government policy was clear. At the same time, because of the expectation that financial results at NSPI would deteriorate based on the legislation, S&P reduced its Financial Risk rating by one category to “aggressive”. The combination of these two changes results, based on the table in Figure 2 above, in a

> standalone credit rating of BB+, and the company would have lost its investment grade status. However, as a subsidiary of Emera, NSPI was accorded the benefit of a one notch advantage, and thus was reduced only to BBB-, instead of BB+.
>
> As of S&P's most recent report, in January of 2025, the rating of BBB- was affirmed, and a specific mention was made relating to the financial risk metric FFO:Debt, such that "We could lower our ratings on NSPI over the next 12-24 months if: Financial measures deteriorated, with FFO to debt consistently below 10%, or We lowered our rating on parent Emera." It is perhaps worth emphasizing the term "consistently below 10%", in the quote above.
>
> [Exhibit N-36, pp. 12-13]

[297] Morrison Park explained the consequences of a downgrade of NS Power's credit rating. It listed several circumstances that could lead to an additional $25 million or more in costs per year for ratepayers [see Exhibit N-36, pp. 24-25]:

- NS Power is forecasting a $250 million bond issuance in 2027. Based on Government of Canada 30-year bond rates at the time of Morrison Park's report, and recent yield spreads on the company's bonds, the consultant estimated the bond interest rate to be under 5%. If the utility suffered a downgrade, the interest rate it could achieve on the bond issuance would be at least 2% higher. The additional cost for ratepayers would be about $5 million per year.
- Similar increases would apply to additional bond issuances, if there is a downgrade, noting it may take years to improve a credit rating following a downgrade. Morrison Park stated that NS Power will have to refinance about $800 million of maturing bonds over the next 10 years, with similar increased interest costs to that described above.
- The same would apply to NS Power's debt financing for its Reliability Plan, which NS Power has forecast at $1.3 billion over five years.
- As outlined in NS Power's response to Morrison Park IR-6, a downgrade from an investment grade rating could result in a default and penalties to the beneficial

financing arrangements received from the Government of Canada for recently approved large projects to support renewables on the grid and improve reliability. It could cause a 3% increase in the interest rate on NS Power's Battery Energy Storage Project and an increase in the return paid to the Canada Infrastructure Bank from 1.15% to 9.00% on the Wasoqonatl Transmission project for the NS/NB Reliability Intertie.

[298] However, Morrison Park also noted that bond markets do indeed react favourably to positive developments affecting NS Power, which it demonstrated in its report by examining the movement in yield spreads as between corporate bonds and government bonds in NS Power's instance relative to Hydro One in Ontario. It noted that bond markets appear to react more contemporaneously with positive developments than credit rating agencies. It referred to a few developments to address NS Power's FAM balance that occurred after the credit rating downgrade in late 2022, including the Government of Nova Scotia's purchase of $117 million of FAM receivables in February 2024 and the Government of Canada providing its $500 million Federal Loan Guarantee in late 2024 to address the remaining FAM balance. Morrison Park noted that NS Power's bond yield spreads decreased (i.e., improved) after these developments:

> … the NSPI bond yields do decline from the January 2023 peak depicted in the charts, despite the fact that no improvements in credit ratings were announced throughout this period. [Emphasis in original] The various announcements about FAM arrangements with government no doubt contributed to the decline in NSPI yield spreads, as did the normalization of regulatory affairs, but in general that decline was gradual.
>
> …
>
> All of these observations suggest that the bond market reacts to events as they occur, and processes all available information, despite the lack of changes in credit ratings, or insights by credit rating agencies. <u>It is also clear that the concrete steps to solve problems at NSPI – such as the securitization of the stranded FAM balances – was rewarded by the markets with lower yields on NSPI bonds.</u> [Emphasis added]
>
> [Exhibit N-36, p. 18]

[299] Morrison Park confirmed that securitization should reduce the business risk faced by NS Power, which could improve its credit metrics and its resulting credit rating. While it noted that a positive result in both the securitization and the proposed rate increases could provide more relief than what is required to ensure NS Power does not suffer a credit downgrade, the reverse is not true:

> Given the magnitude of the impacts of each of the two initiatives separately, should NSPI's rate requests be rejected and its securitization plan not bear fruit, then it would be a certainty that the 10% FFO:Debt target would be missed in both [test] years.
>
> [Exhibit N-36, p. 23]

[300] Further, as noted above, Morrison Park indicated that NS Power must refinance about $800 million of long-term debt over the next 10 years. Morrison Park stated that interest rates are now historically low compared to the rates on existing 10, 20 or 30 year bonds coming due over the next few years. Thus, all else being equal, NS Power should be in a position to refinance maturing debt with lower cost debt. This would represent lower costs for this debt than what is currently embedded in rates.

[301] In his evidence, Mr. Madsen of Emrydia said he had no issues with NS Power's proposed securitization, but recommended the Board conduct a full review of the final securitization in a future process, including the recovery period of all costs. He noted that securitization is used to:

> … allow for lower cost recovery of costs incurred by a utility that if included in base rates would cause rate shock or negatively impact the financial integrity of the utility.
>
> The main benefit of securitization is that it provides for recovery of the costs based on low-cost debt financing, which is generally available as the cost recovery is either guaranteed or highly certain, and over a finite period of time. Absent denying recovery of the costs in rates, which has its own implications, securitization poses the lowest general cost to customers.
>
> [Exhibit N-34, p. 117]

[302] Given Morrison Park's evidence that a downgrade to NS Power's credit rating could lead to an additional $25 million or more in interest costs per year, it appears

that securitization, if allowed to proceed, could provide comfort about the utility's credit rating and potentially be a contributing factor to reduced costs for ratepayers over the long term. As noted above, bond markets have reacted favourably to positive developments impacting NS Power.

[303] NS Power had not applied for securitization as the end of 2025 approached. On December 22, 2025, NS Power wrote to the Board requesting a securitization deferral pending the legislation being proclaimed and regulations enacted:

> As stated in response to NSEB IR-89(a-c), while NS Power believes it will be able to proceed with a securitization application as soon as enabling regulations are in place, it now anticipates that securitization will be in place, at the earliest, by the end of Q1 2026. As such, and consistent with the stated intent set out in the GRA, NS Power is requesting Board approval to defer the depreciation expense and financing costs of the subject assets at WACC on an interim basis until such time as securitization is in place. As confirmed in response to NSEB IR-89(d), NS Power is proposing to add the deferred costs to the balance being securitized. NS Power anticipates that any assessment of the amount of deferred costs to be added to the securitized balance would be assessed by the Board as part of the application to approve securitization.
>
> NS Power has discussed this request with customer representatives, but they have not provided their confirmed positions on the matter.

[304] NS Power was unable to report any progress on this issue at the hearing in January 2026. It confirmed in questioning from the Board that it had not received the intervenors' views about the proposed deferral, subject to what position they would take at the hearing. Further, at the hearing, the utility's estimated timeline for completion of the securitization was extended to Q2 2026, possibly Q3 2026, depending on the enactment of the regulations. However, the NS Power panel testified that it continued to engage with the provincial government to pursue this process:

> **Q.** And I know there's been discussion through the Application other documents with respect to NSPI kind of waiting for the Regulations with respect to the securitization. What is the current status of the Regulations?
>
> **A.** (Williams) The Regulations are with government, effectively. So Regulations obviously need to be put into effect from the provincial government, and so we're waiting for that to occur.

Q. Do you have any idea of how long that might take?

A. (Williams) I don't have any specifics on that, and that's why I was kind of trying to give a general timeline in terms of front half of this year to make the application, have it determined and have securitization in place.

Nova Scotia Power certainly has made efforts and will continue to make all efforts to ensure that as soon as we're able to move forward with that application we would do so without any delay.

Q. And just to be clear, do the Regulations have to be in place and enacted prior to your making the application?

A. (Williams) Yes, I believe so. The relevant provision of the PUA, which would also need to be enacted and would -- is very broad and very general and just provides for the issuance of Regulations, and the Regulations would provide the basis for that application.

[Transcript, January 7, 2026, pp. 210-212]

[305] In questioning by PHP counsel, NS Power confirmed that a six-month delay in proceeding with the securitization (i.e., by July 1, 2026, instead of January 1, 2026), would reduce the savings for NS Power and ratepayers realized over the two-year test period by one quarter (i.e., $22.5 million in reduced savings).

[306] NS Power also confirmed that it had completed its preliminary steps to proceed with the securitization once the regulations are enacted by the Province. It stated that once s. 35G is proclaimed, the regulations are enacted, and the Board issues its financing order, the securitization could be completed in short order, on a timeline similar to what had transpired in the FLG2 debt issuance process conducted in December 2024 to refund $500 million of the FAM balance to ratepayers (Transcript, January 9, 2026, pp. 904-905).

[307] At the very close of the hearing on January 13, 2026, NS Power indicated it had received information that could impact the timing of the securitization. The company indicated it would write to the Board immediately following the hearing to report on these

new facts, based on a message agreed to by the interveners present who had signed the settlement agreement. On January 14, 2026, NS Power wrote as follows:

> In order to ensure the public record of matter M12451 is as complete as possible, NS Power writes to confirm that, as communicated during the confidential portion of the M12451 hearing on January 13, 2026, the exact timeline of securitization remains uncertain, but that NS Power continues to believe in its eventuality and that it is in the best interests of customers. [Emphasis added]
>
> [Exhibit N-65]

[308] In closing submissions, the Department of Energy indicated that the Province is not currently inclined to allow the securitization to proceed due to concerns about the value of coal plant assets that would be securitized, submitting that this amount should be reduced (as canvassed elsewhere in this decision). The Province described its position as follows:

> 92. For initiatives that demonstrably protect ratepayers, the Department is all in. However, there remains considerable uncertainty regarding the appropriate value of coal assets that would form the basis of any securitization initiative. Without a clear and comprehensive understanding of these assets' appropriate value, it would be irresponsible to lock in a price that commits ratepayers to funding them into the future and for the Province to be financially exposed to risk through NS Power's request for the province to backstop the securitization loan.
>
> …
>
> 94. The Province will not implement regulations creating a situation, securitization or otherwise, that could result in financial harm to ratepayers or fail to demonstrate clear ratepayer benefits. It could be that under certain circumstances some form of securitization makes sense. This conclusion has not been reached with respect to NS Power's proposition and as such the Province does not accept it. Until it is proven to save ratepayers money, it is a nonstarter.
>
> 95. The Department has worked with NS Power to try to develop an approach that would benefit ratepayers but to date has been unable to do so.
>
> 96. To this end, the Department also has significant concerns with assumptions NS Power made about the Province's position with respect to securitization. Specifically, the Consensus Agreement seems to suggest that NS Power and consumer representatives shared an understanding that securitization of Decarbonization Deferral Account liabilities was imminent. In fact, there has never been any firm commitment from the Province that it will change regulations to permit securitization.
>
> [Department of Energy Closing Submissions, p. 15]

[309] However, in their closing submissions, NS Power and the customer representatives continued to support securitization and highlighted the savings that would accrue to ratepayers from the securitization. NS Power noted that the Province had taken initial steps to provide a process for securitization through the enactment of s. 35G of the *Public Utilities Act* and had outlined its support of this process in a letter to the utility dated May 6, 2025, from Karen M. Gatien, Deputy Minister of Energy, who stated:

> In order to reduce electricity costs for Nova Scotians, I am writing to confirm that the Department of Energy is committed to continuing its engagement with Nova Scotia Power and other relevant stakeholders to develop an approach that would allow for the Nova Scotia Energy Board to issue a financing order. A financing order is used in section 35G of the *Public Utilities Act*, in order to facilitate the securitization of electric utility costs.
>
> Any such approach would not come at a cost to the Government of Nova Scotia. It is my hope that this work can be successfully completed within the year.
>
> [Exhibit N-7, Appendix 8F, PDF p. 650]

[310] Further, NS Power noted that the DDA approved during the 2023-2024 GRA proceeding (M10431) was identified as an initial step in the treatment of retired thermal assets, including as a preliminary step to securitization. It stated the "purpose of the DDA was to avoid the need to accelerate the recovery of the remaining costs of the coal assets and the resulting substantial increase in rates that would occur if a conventional depreciation study update was undertaken". Christine Runge, of Power Advisory LLC, a consulting firm engaged by the Province in that matter, recognized that the DDA could potentially be the best option for recovery of costs associated with the early retirement of thermal generation assets. Nevertheless, she stated that it should not be approved unless more information is provided before assets are transferred to the DDA, including proposed amortization periods and rate impacts (see *NS Power 2023-2024 GRA* Decision, pp. 113-114). The Board sees this as consistent with a process that would

ultimately implement securitization, which would have to come to the Board in a separate process for approval.

[311] In the interim, most of the customer representatives supported the securitization deferral but did not agree with NS Power that the deferral should be made effective retroactive to January 1, 2026. In their view, the securitization deferral should only take effect when new rates are implemented. Otherwise, these intervenors argued that this would amount to double recovery because, as the Small Business Advocate submitted, depreciation expense and financing costs for these assets are already embedded in NS Power's existing rates. The MEUs stated that the deferral should only take effect when any costs related to these assets are not included in rates, after new rates come into effect. MEUs' counsel suggested this would be "consistent with the intent of the settlement agreement and the GRA as filed, which contemplated new rates taking effect consistent with the start date of any potential deferral on account of a delay in securitization". Finally, the Industrial Group submitted that retroactive application of the deferral would offend a well-recognized ratemaking principle that deferrals should only apply prospectively.

[312] In its reply submissions, NS Power submitted that the intervenors' concerns about "overcollection or double recovery are unwarranted":

> • First, the current rates are based on a revenue requirement developed in a prior test year using forecasts that predate these circumstances. Attempting to retroactively attribute specific current costs to that framework would be artificial and unreliable;
>
> • Second, rates were capped in 2023 and 2024, with the result that the Company's full revenue requirement was not funded and therefore these costs have not been recovered;
>
> • Third, in recent years the Company has consistently earned below its allowed return on equity, further confirming that incremental costs of this nature are not being absorbed through existing rates;

> • Fourth, the Company is already bearing significant unrecovered costs in the period between January 1 and the issuance of the Board's decision in this proceeding – a period that coincides with peak winter sales and system stress. That burden should not be compounded by requiring the Company to absorb additional costs associated with an initiative that has broad stakeholder support, is plainly in customers' long-term interest, and whose timing is largely outside the Company's control; and
>
> • Fifth, the presence of the earnings cap requiring that anything recovered over 9.25 percent is returned to customers through the FAM provides a safeguard in the, highly unlikely, scenario where earnings reached that level as a result of a January 1, 2026 deferral effective date.
>
> [NS Power Reply Submissions, February 6, 2026, pp. 34-35]

[313] Mr. Madsen also had concerns about NS Power's proposal to defer the depreciation expenses and financing costs at WACC if the securitization is delayed:

> While I do not oppose the securitization proposal, I do oppose NS Power's proposal to defer depreciation and financing costs on the assets at its WACC if the securitization is delayed. NS Power has not adequately demonstrated why the delay occurred. Additionally, it is in the interest of all parties, including customers and NS Power, that the details of the securitization are finalized quickly to ensure rate certainty for customers. Allowing for recovery of WACC on unrecovered costs provides a weak incentive for NS Power to ensure the process is completed in a timely manner.
>
> Additionally, I note that the period of delay appears to be a matter of months. It is customary for return on such amounts to be approved by a regulator where there is a substantial delay that is outside the control of the utility. The context of this delay is one that is not substantial. The delay is also not clearly outside the control of the utility.
>
> Accordingly, I support simple deferral of any amounts related to depreciation and financing costs to the extent the securitization is delayed. Simple deferral of only the specific dollar amounts, after review of all supporting calculations for those amounts is appropriate for the above reasons. …
>
> [Exhibit N-34, p. 120]

3.5.1.2.1 Findings

[314] The approval of the potential securitization is not before the Board in this application. The sole issue in the present matter is whether the Board should approve the securitization deferral. NS Power asked for this deferral in case the securitization is delayed such that it cannot occur, "in whole or in part", by January 1, 2026. NS Power proposed that the depreciation expense and financing costs of the unrecovered net book value of the thermal assets within the scope of the DDA be deferred at WACC on an interim basis. It is now known that the securitization did not occur by January 1, 2026.

Securitization cannot currently proceed in Nova Scotia because the enabling statutory provision has not been proclaimed and regulations to implement this mechanism have not been enacted by the Province.

[315] Given the Department of Energy's submissions, the Board shares the Consumer Advocate's view that, at least at this point, "the achievement of securitization appears to be very much in question". Clearly, the Consumer Advocate is correct when he observed that the "regulatory amendments necessary to facilitate securitization will not happen without the support of the Province". Nevertheless, in their closing submissions, all the customer representatives expressed their support for the eventual securitization of the subject thermal assets:

> • Finally, the MEUs would also like to take the opportunity provided by the closing submissions to reiterate their support for NS Power's efforts to securitize approximately $700 million of assets in the Decarbonization Deferral Account ("DDA") over the GRA period. Securitization is an approach that lowers costs for customers … (MEUs, p. 4);
>
> • …the securitization of the DDA assets would result in a significant savings for current NSPI ratepayers, … While approving securitization is not before the Board today, it is important that the Board give it the appropriate consideration as the assumptions regarding securitization, and its benefits to rate payers, form an important part of the GRA. Should securitization not proceed during the test period, there could be significant financial impacts for NSPI ratepayers, which cannot be avoided. (Small Business Advocate, p. 7);
>
> • A key feature of the GRA and the Settlement Agreement is the securitization of the thermal assets of the Utility, which it values at approximately $700 million dollars. Securitization would remove the net book value of these assets from Nova Scotia Power's rate base and significantly reduce its revenue requirement for the test years. (Consumer Advocate, p. 9);
>
> • The use of securitization to achieve cost savings was a critical component of the Consensus Agreement from the ratepayer perspective. … NS Power should continue its efforts to pursue securitization. (PHP, p. 8);
>
> • … The Industrial Group has consistently supported securitization of NSPI's thermal assets, now contained within the Decarbonization Deferral Account ("**DDA**"). The evidence filed to date confirms that this proposed treatment will yield substantial savings for ratepayers: currently estimated at approximately $85 million over 2026–2027, … In the GRA negotiation process, securitization received unanimous support from customer representatives as the preferred solution for financing the DDA assets. … Not only have customer representatives viewed securitization favourably, but recent credit rating reports from S&P and DBRS Morningstar, also highlight the value of securitization mechanisms more broadly. (Industrial Group, pp. 10-11).

[316] These intervenors do not oppose the proposed securitization deferral, except in one important respect. As noted above, the intervenors do not agree that the deferral be effective retroactive to January 1, 2026.

[317] The Board accepts the evidence of NS Power, Morrison Park, Emrydia and the submissions of the customer representatives that securitization, if allowed to proceed, could benefit ratepayers by lowering financing costs related to the retirement of thermal assets. Past examples that were similar to securitization clearly showed that the result is lower costs for ratepayers. Such processes include the Government of Nova Scotia's purchase of $117 million of FAM receivables in February 2024. This transaction acted to lower NS Power's borrowing costs and avoid rate shock for customers.

[318] In turn, Morrison Park noted that positive developments affecting NS Power had a favourable impact on the utility's relative borrowing costs going forward, as measured by a reduction in NS Power's bond yield spreads compared to government bonds. Morrison Park indicated that bond markets react favourably to positive developments, typically lowering NS Power's financial and business risks. Morrison Park highlighted that "concrete steps to solve problems at NSPI – such as the securitization of the stranded FAM balances – was rewarded by the markets with lower yields on NSPI bonds".

[319] NS Power has been in a precarious financial situation since its credit rating was downgraded to BBB- in late 2022. Morrison Park confirmed that a further downgrade of NS Power's credit rating "would have serious long-term consequences, as the company would no longer be investment grade. All new issuances of debt would be significantly more expensive than was historically the case". It said this could lead to an

additional $25 million or more in interest costs per year, due to increased interest rates on new debt and on refinanced debt on maturing long-term bonds. There would also be increased rates due to defaults and penalties to the beneficial financing arrangements received from the Government of Canada for recently approved large projects to support renewables on the grid and improve reliability, such as a 3% increase on NS Power's Battery Energy Storage Project and an increase in the return paid to the Canada Infrastructure Bank from 1.15% to 9.00% on the Wasoqonatl Transmission project for the NS/NB Reliability Intertie.

[320] The Board places significant weight on Morrison Park's evidence. Mr. Colaiacovo, Managing Director at Morrison Park, was qualified as an expert to provide opinion evidence about utility financing. Morrison Park is a Canadian independent investment bank which provides advisory services for mergers, acquisitions and capital raising, and provides expert witness testimony before courts and regulators. About 40% of its work is in the energy and utilities sector. He explained the practical impact of a potential credit ratings downgrade on the borrowing costs incurred by NS Power, which are ultimately borne by ratepayers. He confirmed that prior steps taken to address issues, such as the securitization of NS Power's FAM balance, was "rewarded by the markets with lower yields on NSPI bonds".

[321] It was confirmed at the hearing that a six-month delay in securitization to July 1, 2026, would reduce the estimated $90 million savings for NS Power and its customers by about one-quarter (i.e., by $22.5 million). However, if securitization does ultimately proceed, savings could still be realized for the remaining part of the two-year test period and beyond.

[322] As noted above, the approval of the potential securitization is not before the Board in this application. Whether securitization ultimately proceeds is a policy matter for the Province to decide.

[323] NS Power requested the deferral account in case the Province delayed or was not prepared to proclaim s. 35G of the *Public Utilities Act* and enact regulations to allow the securitization to proceed. However, in its closing submissions, the Department of Energy stated that “it could be that under certain circumstances some form of securitization makes sense”. While the Province has shown support for this mechanism in the past by enacting s. 35G in 2024, and by providing a letter of support from Deputy Minister Gatien in May 2025, the Province is not prepared to allow the securitization to proceed at the present time. As canvassed elsewhere in this decision, this position is based on the valuation of the coal plant assets NS Power seeks to securitize.

[324] The only securitization related issue in this application is whether the Board should approve the securitization deferral. The Board finds that it should. The depreciation expenses and financing costs proposed to be deferred relate to assets covered by the scope of the DDA that will continue to be used and useful in the test years. These are costs that would normally have been included in NS Power’s proposed revenue requirements for the test years but, anticipating that the net book value of these assets would be removed from rate base through securitization, NS Power did not include them. While NS Power may have been overly optimistic in doing so, its decision was intended to secure an early benefit for customers from securitization in this general rate application and there is no basis to disallow the recovery of these costs for that reason.

[325] NS Power continues to be optimistic that securitization will occur at some point. However, the Board is concerned about the continuing accrual of these decommissioning and financing costs in a deferral account when they should be included in present rates. This cannot continue indefinitely. To encourage NS Power to deal with this issue on a timely basis, NS Power will only be permitted to earn WACC on this deferral during the test period. After that, subject to a further or other order of the Board, NS Power may only earn at its weighted average cost of debt and must seek leave of the Board, in advance, to continue to accrue amounts to this deferral account after December 31, 2027.

[326] Accordingly, the Board approves the securitization deferral for the thermal assets within the scope of the DDA, including the depreciation expense and financing costs related to these assets. However, the Board finds that the deferral account must only take effect when the new rates are implemented. The Board agrees that it would offend accepted ratemaking principles to retroactively apply the deferral. It would amount to double recovery to the extent that costs related to these assets are already embedded in existing rates.

[327] The Board accepts PHP's description of the problem and why it must deny NS Power's request to retroactively apply the deferral:

> Effectively, NS Power is asking to recover costs associated with to-be securitized assets differently than other similar generation assets simply because NS Power has proposed to securitize them, and did not have new rates in place before the assumed securitization period. If permitted, this would provide NS Power with the opportunity to defer and recover costs for the to-be securitized assets in advance of the Board's approval of new general rates for similar assets.
>
> The timing of securitization is not the issue. Consider what would happen in the event securitization never occurs. If NS Power's proposal is approved, it could apply for recovery of the depreciation and financing costs associated with those assets starting from January 1, 2026, even though the Board's approval for new rates associated with the 2026 test year revenue requirement did not occur until sometime later in 2026. This would result

> in customers paying more than if securitization was never put forward as a concept in the first place.
>
> In support of its proposal, NS Power attempted to argue that the costs of the assets are not necessarily included in existing rates because of the way rates were capped. But it is NS Power that is in control of the timing of its rate applications. There is no dispute that these same assets were included in the revenue requirements NS Power proposed as part of the 2022-2024 GRA that led to the establishment of existing rates. To the extent that existing rates are not sufficient to meet NS Power's revenue requirements, it remains NS Power's obligation to bring forward GRAs in a timely manner.
>
> [PHP Closing Submissions, January 30, 2026, pp. 7-8]

[328] It is up to NS Power to effectively manage its regulatory calendar. It only filed its GRA in late September 2025, practically ensuring that the matter would not be concluded before year-end. Given what is now known about the Province's position on securitization, NS Power's expectations about completing the securitization by year-end of 2025 were no doubt unrealistic. Notwithstanding its misplaced belief, if NS Power wished the deferral to be effective January 1, 2026, it should have pursued that issue diligently to ensure that it would not offend the well-recognized principle against retroactive ratemaking, as described elsewhere in this decision. The carriage of that issue was within NS Power's control if it wanted the matter resolved before year-end. Failing that, the deferral, once approved, can only become effective when new rates are set by the Board.

[329] There is also an issue about the return to be applied to the balance of the securitization deferral account. The Board notes the concerns expressed by Emrydia but finds that WACC can be applied during the test years as set out above.

3.5.1.3 EIFEL Deferral

[330] NS Power has requested the ability to create a regulatory deferral to allow it to recover an incremental tax expense if an exemption is not enacted by the

Government of Canada with respect to a tax provision entitled the “excessive interest and financing expenses limitation” (EIFEL).

[331] The EIFEL provision was enacted in Bill C-59, effective January 1, 2024. However, in August 2025, the federal government released an update to the EIFEL rules which included an exemption for regulated utilities. The Government repeated its intention in the Fall of 2025 to implement the exemption. To date it has not been enacted.

[332] NS Power elected to remove this potential expense from its forecast revenue requirement because it believes there is a “high potential” that the exemption will be granted. If not granted, it has requested the EIFEL deferral. The parties to the settlement agreement agreed to defer the incremental tax expense of about $7.5 million over the 2026-2027 test period if the exemption is not allowed.

[333] Doane Grant Thornton confirmed at the hearing that the state of the exemption remained uncertain. It stated that it is not uncommon for uncertainty over such new tax rules to continue over an extended period, including over successive fiscal periods. In the absence of the deferral, Doane Grant Thornton stated it would be appropriate for the expense to be included in the forecast revenue requirement. It agreed that the EIFEL deferral was reasonable.

3.5.1.3.1 Findings

[334] Based on the evidence of NS Power and Doane Grant Thornton, the Board finds it appropriate to approve the EIFEL deferral.

3.5.1.4 PHP Deferral

[335] PHP currently takes service from NS Power under the Extra Large Industrial Active Demand Control (ELIADC) tariff, which is a Below-the-Line (BTL) tariff. The cost-

of-service study supporting this general rate application assumed that PHP would take service under a new Above-the-Line (ATL) tariff on January 1, 2026.

[336] However, that did not occur. On March 31, 2025, NS Power applied to extend the ELIADC tariff for its third term, effective January 1, 2026, until December 31, 2026, inclusive. The Board approved the extension by decision letter dated September 22, 2025 (M12184) but ordered amendments to the tariff and further reporting. Further, in keeping with NS Power's statement that its objective was to apply for a successor tariff in 2025, to be available to PHP in 2026, prior to the PHP Goose Harbour Lake Wind Farm being commissioned, the Board directed NS Power to apply for the successor tariff by December 31, 2025.

[337] NS Power applied for the successor tariff on December 29, 2025 (M12661), requesting approval of the Extra Large Industrial Dispatchable (ELID) Tariff, an ATL tariff. It noted that the intention is that PHP will subscribe to this tariff on, or before, January 1, 2027, as the ELIADC tariff expires at the end of 2026.

[338] As noted above, NS Power's GRA was based on PHP being treated as an ATL customer in the 2026-2027 cost-of-service study. NS Power said it expected the provision of ADC (i.e., Active Demand Control) service to be proposed as a rider to the new ATL tariff and that any approved payments to PHP for ADC services were expected to be recovered from ATL customers. Other proposed features of PHP's ATL treatment included an interruptible credit (equal to the Large Industrial Interruptible Rider (LIIR) credit) and the value of priority interruption service provided, if any (modeled as a 10% premium to the LIIR credit).

[339] NS Power's GRA requested a PHP Deferral to track any revenue differences between the assumptions in the GRA cost-of-service study treating PHP as an ATL customer and the eventual ELID tariff, in the form ultimately approved by the Board. The GRA adopted a clause in the settlement agreement that the PHP Deferral account would apply in the following scenarios:

- the Board's decision on the PHP tariff or ADC rider differs from the ATL GRA tariff assumptions;
- the tariff is not available for PHP to take service under it as of January 1, 2026; or
- PHP decides the outcome of the ADC and tariff processes is not satisfactory.

[340] In response to Undertaking U-2, NS Power estimated that $18.2 million would accrue in the PHP Deferral account if PHP remains as a BTL customer for the entirety of 2026, and there would also be a $5.7 million fuel balance captured under the FAM. NS Power also assumed the PHP load in 2026 was the same as that assumed in the GRA. The Industrial Group noted that these amounts did not account for delays in PHP's Goose Harbour Wind Project.

[341] While the PHP Deferral contemplated in the settlement agreement was agreed to by the customer representatives, it is clear from the questioning at the hearing that there may be uncertainty about parts of the scope of the deferral account as between NS Power and some of the customer representatives. The settlement agreement contained a clause that the parties were free to take any position they wished during the Board's review of the PHP successor tariff.

[342] In his closing submissions, the Consumer Advocate noted that, as an ATL customer, PHP will assume significant costs that would otherwise be allocated to other

customer classes. Further, he noted that if PHP considers that the new tariff is not satisfactory, or that the Board does not approve the proposed ATL tariff, PHP could remain a BTL customer under the ELIADC tariff for all of 2026, which would impose additional costs on the other rate classes. The Consumer Advocate stated that there already appear to be areas of disagreement between NS Power and PHP about the proposed tariff. The GRA and the settlement agreement contemplates PHP's firm, plus interruptible load, at a forecast of 65 MW, while PHP takes the view that "the three coincident peak demand determinants applicable to PHP should be set at the firm demand level of 8-MW" (p. 6 of the M12661 application). The Consumer Advocate noted that these "unanswered questions bear directly on the terms of the Settlement Agreement and the resulting GRA".

[343] The Industrial Group noted that the terms about the treatment of PHP in the settlement agreement were "intentionally drafted" and are the lengthiest section of the agreement. It submitted that the PHP Deferral account was "intended to capture only specific variances ordered by the Board" and the only issue in this proceeding "is the proper scope and parameters of the PHP Deferral Account" as reflected in the three above scenarios set out in the settlement agreement. It said that there was no proposed PHP successor tariff at the time the settlement agreement was negotiated, so that the GRA's cost-of-service study made various assumptions about:

> … certain load and demand characteristics of PHP under an ATL rate. The COS embeds fuel cost savings and PHP's contribution to fixed costs but does not quantify the value of "active demand control" ("ADC") which was contemplated to be negotiated between PHP and NSPI.
>
> [Industrial Group Closing Submissions, January 30, 2026, p. 8]

[344] The Industrial Group noted that the settlement agreement was signed on August 29, 2025, but that NS Power did not file its application for a successor tariff until

December 29, 2025, despite assuming that the GRA's cost-of-service study was forecast based on receiving Board approval for the successor tariff in time for it to be implemented by year-end. Given that NS Power and PHP controlled the timing of the successor tariff application, the Industrial Group stated that it reserved the right to argue whether the costs sought to be transferred to the deferral account met a prudency test. Further, it noted that in the ELID application (M12661), NS Power appears to ask for "expanded risk mitigation parameters beyond these agreed terms [of the settlement agreement]", noting that the utility uses language such as "including but not limited to..." in referring to variances to be included in the deferral account.

[345] The Industrial Group also referred to NS Power's testimony, which it said appeared to potentially expand the scope of the deferral account:

> **Q.** (Rudderham) I guess I'm trying to clarify what exactly NSPI is looking for approval from the Board for this deferral account because there needs to be some predictability here as to what's going to be deferred and recovered at a later time versus what is not going to be deferred and recovered from other customers. So can you clarify that?
>
> **A.** (Williams) Yeah. Well, I'm trying to. And I understand the frustration, but I think the reality is that we need to ensure we're not closing the door to something that we just may not be seeing or foreseeing as a result of this tariff application.
>
> I do think we have put forward appropriately worded, appropriately stringent criteria as to what would be applicable or what would be eligible for the deferral. And it goes back to -- when I say principles, it's really those three bullets from the settlement -- or three bullets from the General Rate Application that are based on the Settlement Agreement and then we've expanded on those, expanded on those here in the PHP application to try to give a bit more clarity as to what those items could potentially be. [Emphasis added]
>
> [Transcript, January 8, 2026, pp. 591-592]

[346] The Industrial Group requests that the Board confirm the "defined and limited scope of any deferral account" as described in the settlement agreement and the GRA, asserting that the PHP Deferral should not cover "any and all variables" relating to "whether and when" PHP takes service as an ATL customer. It also asks the Board to confirm that the scope of the deferral account does not include "risks associated with

delays in the Goose Harbour Wind Farm or non-fuel cost changes arising from shifts in PHP's load".

[347] In its report, Bates White concluded that, given the uncertainty surrounding PHP's tariff mechanism for the test period, NS Power's PHP treatment in the GRA was reasonable. It stated:

> … NSPI recognizes the uncertainty regarding PHP's tariff for the GRA period, as well as the nature of any load shifting credits PHP may earn under that tariff. NSPI necessarily needs to make assumptions regarding PHP's tariff arrangements in order to complete its cost of service study and GRA Application, and it has done so. Treatment of PHP in the GRA Application also appears consistent with the terms of the Settlement Agreement, which included treatment of PHP details as a key term.
>
> NSPI's assumptions appear reasonable for purposes of the GRA Application, though as NSPI notes, the actual tariff and ADC credits may differ substantially from what NSPI assumes in the GRA.
>
> [Exhibit N-35, p. 29]

[348] However, Bates White also suggested that it would be beneficial for NS Power to confirm "that its PHP Deferral will account for treatment of the Goose Harbour Lake wind project, should the tariff provisions under which PHP ultimately takes service (and receives credits for load shifting) incorporates services, costs, or revenues from the Goose Harbour Lake wind project". While this was confirmed by NS Power on questioning by Board Counsel, the Board observes that the Industrial Group appears to oppose the possibility of this deferral. The Industrial Group said this was not explicitly agreed to by customer representatives and its inclusion in the scope of the PHP Deferral was a departure from the terms of the settlement agreement.

3.5.1.4.1 Findings

[349] NS Power requests a PHP Deferral account to track any variances in revenue between that which would occur based on the assumptions in the GRA cost-of-service study treating PHP as an ATL customer versus that which results from the eventual ELID tariff, in the form ultimately approved by the Board. This deferral account

was expressly contemplated in the settlement agreement, which also set out various assumptions incorporated into the GRA's cost-of-service study about PHP taking service under an ATL rate.

[350] The eventual balance of the proposed deferral account is material. According to NS Power's response to Undertaking U-2, $18.2 million would accrue in the deferral account if PHP remains as a BTL customer for the entirety of 2026, and there would also be a $5.7 million fuel balance captured under the FAM.

[351] While the deferral account was addressed in the settlement agreement, the scope of the account is somewhat uncertain, at least based on the Industrial Group's submissions. However, no party opposed the creation of the PHP Deferral Account. The Board recognizes that there could be significant variances to NS Power's revenue requirement depending on the final adjudication of NS Power's application for the PHP successor tariff. The creation of the proposed deferral account, and the assumptions underlying it, do provide some certainty for the utility and the customer classes. The Board finds that it is appropriate to approve the deferral account.

[352] As to the scope of the deferral account, the Board considers that it is best defined as expressly set out in the settlement agreement. There was no evidence about the scope of the deferral account except for that provided by NS Power, and a reference by Bates White. It would be appropriate for customers and other parties to provide evidence on the issue if they consider it necessary. Accordingly, as outlined in part (g) of the "PHP Treatment" section of the agreement, the Board finds that the deferral account will:

> … account for any NS Power revenue variances that may arise in 2026 or 2027 from the following scenarios, which costs would be collected/refunded from/to above the line customers:

> (a) where a Board decision on the PHP tariff, including the Active Demand Control Rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA;
>
> (b) where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026; and/or
>
> (c) PHP determines the PHP ADC and tariff processes outcome is not satisfactory.
>
> [Exhibit N-27, NSEB IR-1, Attachment 1, p. 12]

[353] Further, any amounts to be transferred to the deferral account will be assessed against the various assumptions agreed to by the parties as inputs to the cost-of-service study applied in the GRA, as set out in sections (a) to (f) in the "PHP Treatment" section of the settlement agreement. As with all deferrals, any transfer to the deferral account is subject to review for prudency.

3.5.1.5 GRA Deferral

[354] In its general rate application, NS Power asks for a deferral of its GRA-related costs of the present matter and to collect those costs in rates on a straight-line basis over the two-year test period. Such costs include the costs of NS Power, the consumer advocates and the Board, and the expert consultants for the parties. The amount was forecast at $4.0 million, but in the settlement agreement the parties agreed to reduce this amount to $2.0 million, with $1.0 million recovered in each of the two test years.

[355] NS Power equated the treatment of these GRA-related costs to the regulatory deferral approved by the Board in its *2023-2024 GRA* Decision, in which the Board approved the company's request to defer and create a regulatory asset for the costs of the Cost-of-Service Study, Line Loss Study, and Climate Change Adaptation Plan filed in the present application (or by December 31, 2025, whichever was sooner). In the 2023-2024 GRA Settlement Agreement, the parties had agreed to recovery of the costs

of the Cost-of-Service Study and the Line Loss Study in this GRA application, which was confirmed by the Board. The Board also approved the recovery of the costs of the Climate Change Adaptation Plan in this proceeding.

[356] In Undertaking U-9, NS Power was asked to confirm the costs of the Cost-of-Service Study and the Line Loss Study. The company replied that the Cost-of-Service Study costs were included in the total GRA costs. It stated that the cost of the 2026-2027 GRA and Cost-of-Service Study (including the Line Loss Study) was $1,332,440 as of December 2025, subject to adjustments after the close of the 2025 fiscal year.

3.5.1.5.1 Findings

[357] NS Power's costs for preparing and presenting a general rate application have not previously been allowed to be recovered in the test period of that application because they represent costs incurred before the test period. Such costs should be covered in the company's current regulatory affairs budget. Rather, costs approved in a general rate application are intended to apply to costs that are to be incurred prospectively.

[358] The Board is concerned about pushing operating costs into deferrals because they would thus attract a return. The Board has previously noted that if a utility believes it is appropriate to smooth a cyclical type of expense over a regularly recurring period, it expects the utility to explore other options, such as normalizing such costs in its expenses, rather than an option that would attract a rate of return: *NSPML 2024 Cost Assessment* Decision, 2023 NSUARB 231, para. 22.

[359] There are exceptions to the general rule against retroactive ratemaking, but there are specific criteria to justify the deferral of operating costs, which were canvassed by the Nova Scotia Regulatory and Appeals Board in *Halifax Regional Water Commission 2026-2027 General Rate Application*, 2025 NSRAB 142 (M12257):

> [185] Utility regulators in Canada routinely do not allow retroactive ratemaking. This is because traditional cost of service ratemaking involves estimating future annual utility operating expenses over test years. The revenue requirement for the test years is the sum of the allowed projected operating costs plus a rate of return on the utility's capital rate base. The entire process underpinning proposed rates is prospective. Everyone involved in the process knows that projecting expenses and revenues is not an exact science. While there will invariably be differences between projected and actual figures, provided a utility meets its overall revenue requirement, no rate increases are necessary.
>
> [186] The prohibition against retroactive ratemaking is not absolute. Certain forms of retroactive ratemaking are well recognized. They include retroactive adjustments to interim rates and established true-up mechanisms where projected costs included in rates are trued up, either up or down, after actual costs are known. An example of the latter is NS Power's Fuel Adjustment Mechanism. The rationale underpinning these types of exceptions to the rule against retroactive ratemaking is that customers are given notice up front that the rate is subject to change.
>
> [187] The Board recently considered the availability of retroactive ratemaking in situations outside the more recognized forms. NS Power sought to recover $26.4 million in operating costs incurred because of Hurricane Fiona (2024 NSUARB 116). The costs had already been incurred at the time of the application, so it was a case of retroactive ratemaking. The Board said:
>
> > [72] The Board is in general agreement with the Alberta Court of Appeal's approach to retroactive ratemaking. Where there is no express statutory prohibition against retroactive ratemaking, it is beneficial for the Board to have some flexibility to address extraordinary or novel situations by relaxing the rule against retroactive ratemaking so that the interests of both the utility and its ratepayers can be considered, without opening the door to endless rate adjustments.
>
> [188] … In the *Hurricane Fiona* Decision, the Board outlined factors that should be considered when deciding whether to exercise its discretion and allow retroactive ratemaking where the traditional exceptions were not applicable. In that case, the issue was framed as allowing a deferral account so the Hurricane Fiona operating costs could be collected over time, as opposed to expensing them in the year they were incurred. These factors can be applied to retroactive ratemaking generally. They include:
>
> - Whether the expenses are extraordinary or unusual or result from an event which is unusual or extraordinary.
>
> - Whether the expenses are beyond the utility's control and could not have been reasonably anticipated.
>
> - The expenses must be "significant".

- Whether, if not incorporated in rates, the expenses will have a material impact on the utility's financial condition.
- Whether, if granted, the recovery of expenses that have already crystalized will provide significant benefits to ratepayers.

[2025 NSRAB 142 (M12257), paras. 185-188]

[360] The Board finds that the present instance clearly does not fall within the above exceptions. The GRA-related expenses are not due to extraordinary or unusual circumstances; the costs are not significant, nor do they have a material impact on the utility's financial condition; and the costs are not beyond the utility's control. Such expenses were anticipated and should have been included in the prior GRA if they were not already.

[361] The Board denies NS Power's deferral of its GRA-related costs, except for the costs related to the Cost-of-Service Study (COSS) and the Line Loss Study. In Undertaking U-9, NS Power stated that the cost of the 2026-2027 GRA and COSS (including the Line Loss Study) totaled $1,332,440 as of December 2025. In its compliance filing, the Board directs the company to confirm the amount of costs related to the COSS and the Line Loss Study (as it was asked to do in Undertaking U-9) and to deduct the other GRA-related costs from the $1 million amounts included in each of the 2026 and 2027 revenue requirements.

3.5.1.6 Payment of Interest on Deferral Accounts

[362] The payment of interest to NS Power on its deferral accounts is subject to s. 64AB of the *Public Utilities Act*. In its *2023-2024 GRA* Decision, the Board concluded that it was appropriate to exercise its discretion under s. 64AB(3) to set interest on the deferrals at NS Power's WACC. In its subsequent decision related to the 2025 Demand Side Management Cost Recovery Rider (DCRR) (2024 NSUARB 216, M11912), the Board canvassed various issues related to s. 64AB and stated it would establish a generic

proceeding to more thoroughly address and consider issues about the application of that provision. Board Counsel has engaged London Economics International LLC to prepare a report about these issues. In the interim, the Board finds it appropriate to continue to exercise its discretion under s. 64AB(3) to set interest on deferral and variance accounts at NS Power's WACC.

3.6 Rate Base

[363] NS Power's rate base consists of the physical assets and related construction work in progress the utility has invested in to provide power to its customers, such as generating stations and transmission lines. It also includes materials and supplies inventory and a working capital allowance. Rate base further includes financial assets such as a long-term income tax receivable and regulatory deferrals, net of regulatory liabilities. Doane Grant Thornton reviewed and verified NS Power's calculations of forecasted average rate base of $5.58 billion in 2026 and $5.89 billion in 2027.

[364] The calculation of the forecasted rate base is important because it represents the invested balance used to determine NS Power's forecasted return on equity. It is also fundamental to the calculation of depreciation and amortization expenses, as these expenses are based on the invested balances.

3.6.1 Capital Additions

[365] NS Power's capital outlook for 2026-2027 for additions to Plant reflects the company's best estimate of capital investment over the test years at a point in time. The test period investment is intended to support the continued safe delivery of electricity service and ongoing environmental compliance. It is also meant to align with Renewable Electricity Standards and the requirement to phase out coal by 2030. Finally, the proposed level of capital investment over the GRA test period is also aimed at allowing

the company to continue executing on its 5-Year Reliability Plan while continuing to meet the requirements of a growing customer base.

[366] Sustaining NS Power's asset base through capital re-investment generally results in rate base growth. Similarly, capital investments required to comply with regulations and meet the needs of an expanding customer base also drive growth in rate base. In this context, NS Power's average capital assets will continue to increase over the 2026-2027 test period as the company continues to invest in its system. This increase in rate base will be partially offset by NS Power's planned securitization of the assets within the scope of the DDA, assuming of course, that securitization proceeds. If securitization does not proceed, NS Power's rate base will continue to include the assets within the scope of the DDA.

3.6.1.1 Findings

[367] NS Power's estimated capital investment for the GRA test period amounts to $671.3 million in 2026 and $556.1 million in 2027. The capital additions to rate base for the test period have generally been approved by the Board in prior ACE Plan proceedings and other capital expenditure approval applications. However, they also include projects that have not yet been approved by the Board but have been submitted for approval in NS Power's 2026 ACE Plan. In response to NSEB IR-92, NS Power provided a list of capital projects that have not yet been approved by the Board but have been included in the capital budget for the GRA application. Further, in response to NSEB IR-92, NS Power stated:

> NS Power's capital forecast is completed at a portfolio level based upon the anticipated capital investment requirements at the time of GRA forecast development. Certain investments that are included in the test period may not advance during the test period and other projects are likely to differ in the timing of investment as NS Power utilizes its asset management framework to refine the capital plan. While certain investments included in the GRA may not advance, or will advance on a differing timeline, NS Power expects that

> other capital investments will take their place and the overall level of expected capital investment will be similar to that which is included in forecast.
>
> [Exhibit N-27, NSEB IR-92]

[368] During the hearing, the Board noted that the response to NSEB IR-92 included 39 projects with a total forecast 2026 spending of $218 million. The Board also noted that NS Power's recently filed 2026 ACE Plan (M12619), shows total forecast 2026 spending for projects (excluding capital routines) yet to be approved by the Board of roughly $223 million. However, the 2026 ACE Plan includes 20 projects for approval and 47 projects for subsequent submittal in 2026 for a total of 67 projects. Therefore, even though the GRA forecast for 2026 capital spending for projects yet to be approved by the Board is close to the forecast for 2026 ACE Plan capital spending for projects yet to be approved by the Board, the actual projects appear to be quite different.

[369] NS Power explained this discrepancy as a matter of timing between when the GRA projects list was developed versus when the 2026 ACE Plan was prepared. Over this time, the company used its asset management mechanism to update its asset condition and criticality assessment, which resulted in changing priorities for a number of projects. Nevertheless, the overall expected 2026 capital spending estimates in the GRA forecast and the 2026 ACE plan forecast are fairly close. In addition, in Undertaking U-21, NS Power provided a comparison of its actual 2023 and 2024 capital spending to the 2023-2024 GRA forecast spending for those years. In total, the actual capital spending over that period was relatively consistent with the GRA forecast.

[370] During the hearing NS Power also confirmed that it will manage its capital expenditure program over the test period to match the GRA forecast. Therefore, although there is some uncertainty with the capital project additions that are included in the GRA,

because a number of projects are not yet applied for, or not yet approved, the Board finds the total forecast spending on capital additions in the test period to be reasonable.

3.6.2 Maritime Link Capital Projects

[371] NS Power has four Maritime Link transmission capital projects that, by Board Order, have historically been excluded from rate base. The original intent of these projects was primarily to facilitate Nalcor's (now Newfoundland and Labrador Hydro) intended energy export to third parties outside of Nova Scotia. NS Power's expectation when they were built was that the benefit of these projects to Nova Scotia customers, expected to be OATT fees on the exports, would offset the capital and operating costs of these projects. In the 2023-2024 GRA, NS Power requested these projects be included in rate base. It stated that rather than export this available surplus energy, it was retaining it in Nova Scotia to serve provincial requirements, but that the overall benefit of these projects, albeit not the originally expected benefits, outweighed the costs of the projects.

[372] In its *2023-2024 GRA* Decision, the Board did not approve inclusion of the projects in NS Power's rate base. However, the Board defined the test NS Power had to meet to include those assets in rate base. It had to show that the benefits of these projects outweighed the costs to ratepayers. The Board's test stipulated that for a minimum of four consecutive quarters,

(a) the wheeling tariff revenue;

(b) the net economic value of NS Power purchases of additional Nalcor surplus energy (based on actual results following the methodology used in Undertaking U-64); or

(c) a combination of wheeling tariff revenue and the economic value of purchased Nalcor surplus energy,

is at least equal to the combination of depreciation, financing costs, operating costs, and re-dispatch costs.

[373] In the current GRA, NS Power requested Board approval to include the four Maritime Link projects in its rate base, claiming that the company has met the Board test. NS Power's calculation of benefits from the projects in its quarterly benefit reports includes two types of surplus energy: "additional energy" and "bilateral sales". During the hearing in this matter, NS Power was asked to provide an undertaking to show how the Board's test was met. In Undertaking U-24, NS Power provided the calculations it used to confirm it had met the Board's test. Further, in Undertaking U-25, NS Power stated that it purchases market-priced energy from Newfoundland and Labrador Hydro through two mechanisms. NS Power defines these two types as "surplus energy transacted under the Energy Access Agreement" and "bilateral market-priced energy". NS Power asserts that both types of energy are market-priced energy and that their treatment is consistent with the approach in the 2023-2024 GRA proceeding's Undertaking U-64.

3.6.2.1 Findings

[374] The Board notes that Undertaking U-64 in the 2023-2024 GRA referred to the forecast NSP Maritime Link Incorporated surplus energy purchases. While not specifically defined, the Board agrees that, in the context of these specific projects, "surplus energy" means all surplus, including "surplus energy transacted under the Energy Access Agreement" and "bilateral market-priced energy". As such, the Board finds that NS Power has demonstrated through Undertakings U-24 and U-25 that it has met the test for inclusion of the Maritime Link transmission projects in rate base.

[375] The Board notes that inclusion of these projects in rate base is only effective on a go-forward basis. NS Power is not permitted to recover any depreciation expense

already incurred or any lost return on rate base associated with these projects from any period prior to the date of the Board's decision in this GRA. To be clear, the amount to be included in rate base for these projects is the net book value of these assets as of the date of the Board's Order in this matter.

[376] The Board also offers one further caveat. In this particular instance, the Board found that customers received benefits from surplus energy from Newfoundland and Labrador Hydro regardless of whether the energy was market-priced energy transacted under the Energy Access Agreement (EAA) or through bilateral arrangements outside of the EAA. However, there may be situations where the distinction between these two mechanisms is relevant. For example, an assessment of whether there has been compliance with rights and obligations of the parties under the EAA may require that the focus be on energy transacted under the agreement to the exclusion of other bilateral arrangements.

3.6.3 Valuation and "Writing Down" of the Rate Base

[377] The Department of Energy requests that the Board take steps to ensure that NS Power's coal assets are written down by an amount that the Board deems appropriate based on a transparent, comprehensive review of asset lives and amortization schedules, aligned with coal phase-out commitments and the public interest. The Department submits there is a solid legal and regulatory pathway for the Board to require NS Power to bear coal asset write-downs, particularly for life-extension and reinvestment decisions made in the shadow of a known 2030 coal phase-out.

[378] The Department's position is premised on a belief that the value of NS Power's coal plants is "over-inflated" and "that ratepayers should not be asked to carry the cost of outdated infrastructure". It argues:

> Nova Scotians should only be paying for infrastructure that reflects its real remaining usefulness. There remain legitimate questions around whether NS Power is employing actual *values that reflect real remaining usefulness*. [Emphasis in original.]
>
> [Department of Energy Closing Submissions, p. 7]

[379] The Department attributes this over-inflated value of rate base to NS Power's failure to conduct timely depreciation studies and the utility's imprudent investment in coal assets after the lifespans of these assets were materially shortened by government policies. The Department submits that, at least as early as 2016, NS Power knew that its coal assets must be retired by 2030 but did not take this into consideration when valuing its assets. The Department said:

> In the 2022 GRA, the Department submitted that the Company knew as of 2016 that coal must be retired by 2030 and yet it did not take this into consideration when valuing its assets. It is common that accounting and regulatory standards require impairment (write-downs) when early retirement is probable. Nova Scotia's coal-retirement trajectory has been clearly defined in legislation and federal policy for some time, making impairment not only probable but foreseeable. These regulatory changes were well known and NS Power's failure to reflect them in asset valuations has resulted in ratepayers bearing costs that should have been recognized and allocated differently.
>
> [Department of Energy Closing Submissions, p. 7]

[380] The Department submitted that the settlement agreement relating to NS Power's last depreciation study ((M03665), 2011 NSUARB 64) extended the service lives of NS Power's coal-fired generation stations and created a "regulatory obligation" to review these service lives when federal regulations in 2016 required all coal facilities to be retired by 2030. The Department also submitted that NS Power's 2020 Integrated Resource Plan referenced 2040 as the target for phasing out coal plants, which the Department said was inconsistent with this federal legislation.

[381] The Department said that NS Power continued to invest in thermal energy generation while eschewing lower cost renewable resources. The Department submitted this also exposed ratepayers to higher and volatile fuel prices. It submitted that NS Power

did so in the face of clear government policies and legislation mandating the phase-out of coal-fired generation of electricity and, therefore, the Board may properly conclude that shareholders, not ratepayers, should bear the risk of stranded assets.

[382] The Department posits that NS Power's actions were motivated by a desire to maintain a rate base that was higher than it should have been to boost its allowable returns. The Department says this resulted in higher rates for customers.

[383] The Department cites the United States Supreme Court decision in *Smyth v Ames*, 169 US 466 (1898) and the "Alberta based – Utility Asset Disposition (UAD) Line of Cases" to support its position that assets must be "used and useful" to be included in rate base, that utilities – not ratepayers – bear the risk of unrecovered costs, and that utilities can be forced to absorb losses through capital write-downs.

[384] The Department said the Board has the authority to review NS Power's depreciation practices under s. 30(2) of the *Public Utilities Act* and the authority to correct the valuation of the property under s. 33(2). These provisions read:

> **Power to determine value of property of utility**
>
> **30** **(1)** The Board may at any time, with the assistance of such engineers, accountants, valuators, counsel and others as it deems wise or advisable to employ, inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of any public utility used and useful in furnishing, rendering or supplying a particular service to or for the public, as of a date to be fixed by the Board.
>
> **(2)** The Board shall determine the value of such property and assets on the basis of the prudent original cost thereof or by such other method as the Board may from time to time prescribe, deducting therefrom the amount of the accrued depreciation of such property and assets as determined by the Board.
>
> **(3)** For the purposes of this Section, annual and accrued depreciation shall be calculated by the straight line method, so called, or such other method as the Board may from time to time prescribe.
>
> **(4)** The Board may make such rules and regulations to facilitate inquiries under this Section as it may deem convenient, and the rules and regulations so made shall be binding on all public utilities.
>
> **(5)** The Energy Board shall, with the assistance of such engineers, accountants, valuators, counsel and others as it deems wise or advisable to employ,

> (a) inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of Nova Scotia Power Incorporated used and useful in furnishing, rendering or supplying a particular service to or for the public, no later than March 31, 2024; and
>
> (b) set different levels of return on equity for different classes of capital assets of Nova Scotia Power Incorporated to ensure that investment incentives are aligned with ratepayer objectives as submitted to the Board in a hearing for a rate change.
>
> …
>
> **Duty of utility to furnish information**
>
> **33 (1)** Every public utility shall furnish to the Board from time to time, and as the Board may require, maps, profiles, contracts, reports of engineers and other documents, records and papers, or copies of any and all of the same in aid of any investigation and to determine the value of the property of such public utility, and every public utility shall co-operate with the Board in the work of the valuation of its property in such further particulars and to such extent as the Board may direct.
>
> **(2)** The Board shall, thereafter, in like manner, keep itself informed of all extensions and improvements or other changes in the condition of the property of the said public utilities, and from time to time may revise and correct its valuation of the property of such public utilities.
>
> **(3)** To enable the Board to make such changes and corrections in its valuation, every public utility shall report correctly to the Board changes in its property and file with the Board copies of all contracts for changes and improvements at the time the same are executed.

[385] In its reply submissions, NS Power said it is entitled to a "fair return" based on the "regulatory compact". It submitted this is a fundamental principle of public utility regulation recognized as early as a hundred years ago by the Supreme Court of Canada in *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186, and more recently in *ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4. NS Power also referred to decisions of the NSUARB (2012 NSUARB 227 and 2023 NSUARB 12).

[386] NS Power noted that its application in Matter M03665, the proceeding dealing with its last filed depreciation study, assumed retirement dates by 2030 for all steam generation units (including coal units) except for Point Aconi (2039) and Trenton 6 (2037). This was because of "further carbon emissions regulations and a new anticipated

federal government framework". The application proposed to accelerate depreciation rates to account for shorter lifespans than previously estimated.

[387] NS Power further noted that expert evidence in that matter, on behalf of Board Counsel and customer representatives, "disagreed with NS Power's assumed retirement dates claiming that, despite NS Power's reliance on and reference to anticipated environmental regulations and policy, there was no support to use the accelerated retirement dates". The parties agreed to resolve these matters in a "black box" settlement agreement to lower rates for customers in the next general rate application and this was approved by the NSUARB.

[388] The approved depreciation rates were implemented in NS Power's next general rate application in 2013-2014. NS Power did not file another rate application until 2022, its most recent past general rate application. NS Power said many shifts and changes in government environmental policy related to coal-fired electricity generation occurred between these two applications.

[389] NS Power highlighted that under two different agreements, the first of which was in effect between 2015 and 2019, and the second of which came into effect on January 1, 2020, Canada and Nova Scotia agreed that federal requirements relating to coal-fired generation units would not apply in Nova Scotia. These agreements recognized a sufficient equivalency between the regulations in Nova Scotia and Canada. NS Power said because of these "Equivalency Agreements", there was no requirement in Nova Scotia to retire coal generation plants by 2030. NS Power said this requirement was not established until late 2021, when both the federal and provincial governments accelerated their decarbonization policies.

[390] In its 2023-2024 general rate application, NS Power discussed the depreciation of its coal assets and proposed a mechanism to deal with the recovery of the remaining undepreciated and decommissioning costs associated with these assets:

> … The retirement and remaining useful lives of the Company's thermal plants is the input that would drive the most material change in the Company's forecast depreciation expense. With the amendments to the Renewable Electricity Regulations, implementing the requirement for 80 percent renewable generation 2030 RES, and the passing of the EGCCRA, NS Power now has a greater degree of certainty on the timing of retirement of its coal fleet; however, for units no longer used and useful beyond 2030, the retirement timeline would result in significant increases to depreciation expense. In an attempt to mitigate rate impacts arising from these developments, the Company is seeking approval of a DDA, a regulatory asset that effectively eliminates the requirement for a depreciation study for the thermal plants that are incorporated within this regulatory asset and provides flexibility on recovery of the remaining Net Book Value (NBV) of those assets.
>
> [M10431 Exhibit N-16, p. 42]

[391] In the related settlement agreement, the parties agreed in principle to a DDA to recover the net book value and unrecovered decommissioning costs of NS Power's undepreciated thermal assets. They also agreed to engage constructively in a consultative process to confirm the practices and procedures that would be followed to establish the DDA. As with the "black box" settlement in 2011 this had the effect of mitigating the rate impact for customers at the time by avoiding the acceleration of depreciation.

[392] In its reply submissions in this proceeding, NS Power also argued that the UAD decisions and the principles those decisions extracted from the Supreme Court of Canada's precursor "Stores Block" decision (*ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4) have historically had no application outside of Alberta. NS Power said the Department's reliance on the UAD decisions was "fundamentally incorrect" because its coal assets are not stranded but continue to be "used in providing utility service and are anticipated to be used in such a capacity for a number of years to come". Moreover, NS Power submitted that the UAD line of cases

was “brought to an effective end” by the Alberta Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

[393] Regarding the Department’s reliance on *Smyth v Ames*, NS Power said:

> Similarly, the DOE’s submissions refer to and appear to rely upon the USSC 1898 decision in *Smyth v. Ames*. That decision, somewhat ironically, relates to the USSC’s ruling that a Nebraska state law which capped railroad freight rates was unconstitutional because it was confiscatory in nature by preventing railroad companies from earning reasonable compensation for their services and, therefore, violated the 14th Amendment. As a result, *Smyth v. Ames* also is not relevant and has no applicability to the current context.
>
> [NS Power Reply Submissions, p. 19]

3.6.3.1 Findings

[394] A utility is entitled to the opportunity to recover its prudently incurred costs in providing service and an opportunity to earn a reasonable profit – no more and no less. While the Board can disallow costs found to be imprudent or unreasonable, absent such a finding, a utility’s costs must be reflected in the rates paid by customers. The Board cannot disallow the recovery of legitimate costs to make rates more affordable.

[395] Utility investors provide the upfront capital required to purchase or construct utility infrastructure to serve customers, and customers who use that infrastructure repay those costs over time as they receive the benefits of service. To attract and retain this investment, investors are given the opportunity to earn a fair return on the capital invested, as well as ultimately recoup the amounts invested.

[396] This was addressed in detail in the NSUARB’s decision in NS Power’s last general rate application (2023 NSUARB 12, paras. 36-41 and 227-237) and is discussed in more detail later in this decision.

[397] In essence:

> A public utility is obligated to provide services that are reasonably safe and adequate and is entitled to compensation therefor by the charging of rates that are not unjustly discriminatory and will provide the public utility with sufficient revenue to enable it to pay its operating expenses including depreciation and income taxes, and have net earnings

> sufficient to enable it to obtain and service normal and needed capital requirements. It is expected to meet reasonable demands for additional services and to conduct its affairs with efficiency.
>
> [*(Public Utilities Board) v Nova Scotia Power Corporation*, (1976) 18 NSR (2d) 692 (NSSC,AD), para. 26]

[398] As described by the Supreme Court of Canada in *Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186, a fair return means "the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise". A low return on rate base may discourage investment in the utility. It may also lead to a poor credit rating, which will increase its borrowing costs. This may result in the utility's rates increasing just to cover additional borrowing costs. It may even cause it to be excluded from participating in some debt markets altogether.

3.6.3.1.1 The Value of the Rate Base

[399] The "value" of NS Power's rate base, as framed in the Department's submissions, is based on an historic concept that has been displaced by the widely accepted prudent original cost method for valuing utility assets. The prudent original cost approach, which is explicitly referenced in s. 30(2) of the *Public Utilities Act*, is the default valuation method under the statute, and has been explicitly so since 1943 (*Public Utilities Act*, SNS 1943, c 2, s 29(2)).

[400] Two witnesses in this proceeding were qualified as experts in utility depreciation. Mr. Wiedmayer (Gannett Fleming) prepared the depreciation study filed by NS Power in support of its application. This study is based on the original cost method. Likewise, Board Counsel consultant, Mr. Madsen, noted that "Depreciation recovers the original cost of any investment added into utility rate base, such recovery occurring over

the expected useful life of the assets". Neither expert suggested in any way that the value concept advanced by the Department in its closing submissions was an appropriate method to determine the value of rate base or depreciation rates. The Department filed no evidence and conducted no cross-examination of these depreciation experts, so neither of them was provided with any opportunity to respond to or address the theory raised by the Department in its closing submissions.

[401] In *Principles of Public Utility Rates* (Second Edition; Public Utilities Reports, Inc., 1988), Professor Bonbright reviewed the historical development of the legal and regulatory principles for valuing a utility's rate base (note that his second edition dates back nearly 40 years and does not capture developments in this more recent period). He noted:

> For many years the major division of practice and opinion on these issues of asset revaluation has been between the position that as long as the assets remain "used and useful" for their intended purposes, they should stay in the rate base at their original costs, subject only to systematic annual deductions for physical and functional depreciation; and the position that the costs should be written up and down so as to take account of major changes in construction costs or in general price levels. The first position is that of the original-cost net-investment principle of ratemaking - a principle strongly espoused by the FERC (and its predecessor FPC) and FCC, and accepted, with or without qualifications, in the majority of state jurisdictions. The second position is most frequently referred to as the fair value principle – a principle no longer held legally mandatory throughout this country but still accepted in a considerable minority of states (a dozen or less at last count).
>
> [*Principles of Public Utility Rates*, p. 212]

[402] Bonbright refers to *Smyth v Ames* as the "original and most famous pronouncement of the fair value standard". The fair value standard was the subject of much criticism over the years. This included what Bonbright referred to as the "vicious-circle criticism" – the fact that the value of the assets depends on the earnings they are able to derive, which is the very question at issue in a rate case (i.e., the value of the rate base will be used to determine rates and the revenue derived from rates will inform the value of the rate base).

[403] Bonbright notes that out of this criticism sprung the cost-based approach to valuation:

> Impressed with the force of the vicious-circle argument, many writers have gone beyond the point of insisting that ratemaking value must be given a special interpretation in order to qualify it as a plausible rate base. They have also asserted that the measure of a rate base is necessarily cost and not value in any accurate sense. Consistently with this view, they have insisted that the former debates as to the merits of an original-cost rate base versus a fair-value rate base should have been converted into debates as to alternative standards of costs, including various types of replacement cost and various versions or modifications of original cost. The whole philosophy of a fair-return standard of ratemaking, they have declared, is a cost-of-service philosophy. On no account, therefore, should it be compromised or confused by a backdoor introduction of value-of-service criteria of reasonable public utility rates in the guise of value standards of the rate base.
>
> [*Principles of Public Utility Rates*, p. 217]

[404] Bonbright describes two major advantages of an original cost rate base. First, it is administratively superior as it lends itself to quicker and more definitive determinations of value, minimizing expenses to all parties and the regulator. Second, it facilitates access to capital on favourable terms and helps to maintain credit. On this later point, Bonbright states:

> For, although original costs will have become fixed costs at the time of a rate case, they are not fixed cost when first incurred, and it is at this time that investors must balance, *ex ante*, the expected future return on any proposed investment against the presently required outlay of capital. In other words, what induces investment is the expectation of a return on (and return of) costs that will have become sunk as soon as the investors have made their commitments. Whatever scheme of rate regulation will put investors in a position to draw this balance between present outlay and anticipated future return with the most confidence is the scheme most likely to permit a well-managed company to maintain sound financial health at a minimum cost of capital to the consumers.

[405] According to Bonbright (p. 216), “Fair value theory does not appear to be an especially fecund source of logic”. He states that the fair value standard pronounced in *Smyth v Ames* was renounced by the United States Supreme Court in *Federal Power Commission v Hope Natural Gas Co.*, 320 US 591 (1944) (around the same time that the prudent original cost method was first explicitly referenced in the *Public Utilities Act* in Nova Scotia).

[406] The National Association of Regulatory Utility Commissioners' (NARUC's) *Public Utility Depreciation Practices* (1996), referenced in Mr. Madsen's evidence, describes the "value concept" and the "cost allocation concept" in the context of depreciation practices:

> **Value Concept**
>
> The value concept assumes that all depreciable plant, due to forces such as obsolescence, wear and tear, and inadequacy, tends to diminish in value or worth with the passage of time. This value reduction may be dramatic-as when one purchases a new automobile. The new owner needs to do little more than drive it off the dealer's lot in order to put it in the classification of a "used car" with a value often substantially less than the purchase price. On the other hand, the reduction in value may occur much more slowly. For example, heavy duty manufacturing machinery will continue to perform the same operations in the same efficient manner for many years. Depreciation, in this sense, may not be consistent. If manufacturing machinery were producing a product that was in heavy demand for many years and suddenly lost its market, the machinery would rapidly lose value.
>
> All other things being equal, on the day before this sharp demand decrease, the machinery would be nearly as valuable in the production of goods as the day it was first installed (assuming it had been kept in good repair). However, the day after the market disappeared the machine would be practically worthless or valueless.
>
> Similarly, the installation of a new technology offering new or different services may cause existing plant to have little or no customer value. For example, a computerized supervisory control and data acquisition system (SCADA) may make the existing use of chart and pen recorders and the manual operation of gas city gate station valves unnecessary and uneconomical.
>
> This situation suggests that depreciation can be determined through a series of periodic appraisals or estimates of plant value. The decrease in value between such estimates is regarded as a measure of the depreciation attributable to the period between estimates. The estimates could be based on the reproduction cost, market value, or earnings value of the property. Estimates may recognize the changing purchasing power of the dollar or they may be confined strictly to original cost terms. In all cases, some measure of depreciation occurring between estimates can be determined. The customary method is for a competent appraiser to study the effect of factors such as obsolescence, inadequacy, and public requirements, as well as to conduct a physical inspection of the property, or a scientific sample of it, to determine its loss in value since it was first constructed. Regardless of the method employed, in order to achieve consistency, the successive estimates must be made in the same way.
>
> <u>It would, however, be a staggering undertaking to attempt such estimates on an annual basis for complex and extensive utility plant. Therefore, the practice of conducting annual estimates has found little application in the utility industry. It is particularly cumbersome and inadequate because utilities need to record depreciation on a monthly basis for earnings and expense reports. A further complication, of course, is that major technological improvements tend to make questionable any year-to-year measure of depreciation that is determined by this process.</u>

Cost Allocation Concept

This concept recognizes the original cost of the asset as a prepaid expense. As such, it must be allocated to specific accounting periods and realized on income statements during the time the asset is providing service. The unallocated amount, often called net plant or net book (gross plant less accumulated depreciation), is recorded on the asset side of the balance sheet. The cost allocation concept satisfies the accounting principle of matching expense and revenues.

On the income statement, the inflow of resources is revenue. The outflow is expense. Using up the productive capacity of assets in an accounting period is recorded in accounting records as depreciation expense.

As used above, "cost" is based on the cost valuation principle of accounting, with cost being a surrogate for value. The amount of money used to purchase the asset is the basis for the entry in accounting records. This amount is regarded as being definite and immediately determinable. The accounting objectives of verifiability and neutrality are also satisfied.

Equally important to the proper estimation of current net income is the recovery of the investment over its useful life. Depreciation accounting cannot, automatically and of itself, result in the recovery of investment in property. However, if revenues are adequate to cover depreciation expense in addition to other current expense, the investment will be recovered. On the other hand, if revenues are not sufficient to cover the depreciation expense, the investment will not be fully recovered. Recognition of depreciation merely records the fact that costs are being incurred. [Emphasis added]

[pp. 11-12]

[407] More recently, NARUC's publication for the United States Agency for International Development, *Depreciation Expense: A Primer for Utility Regulators* (May 2021), states:

The value concept for determining regulatory depreciation is based on periodic estimations of the asset value. The decrease in the estimated value of the asset can be considered as a measure of the value of depreciation for the corresponding period. The estimation can be made either in terms of the replacement cost, the market value, or the earnings value of the asset, through physical inspections or sample checks regarding obsolescence, wear and tear, and inadequacy of the asset.

However, the value concept is not commonly used for determining the value of regulatory depreciation as it is highly burdensome and creates significant uncertainty both for the regulator and the regulated utility. NARUC (1996, p.11-12) describes the significant drawbacks of the value concept approach:

> *It would (…) be a staggering undertaking to attempt such estimates on an annual basis for a complex and extensive utility plant. Therefore, the practice of conducting annual estimates has found little application in the utility industry. It is particularly cumbersome and inadequate because utilities need to record depreciation on a monthly basis for earnings and expense reports. A further complication, of course, is that major technological improvements tend to make questionable any year-to-year measure of depreciation that is determined by this process.*

> In the cost allocation concept, the original cost of an asset is treated as a prepaid expense. The value of regulatory depreciation is then determined by allocating this expense to specific accounting periods during the time the asset is providing service. The depreciation expense allocated in each accounting period is logged on the regulated entity's income statement, while the unallocated amount, the 'net asset value,' is logged as an asset in the balance sheet.
>
> The cost allocation concept is considered the most appropriate, and it is the one that regulators use for determining the value of depreciation in the context of cost-reflective tariff setting. NARUC (1996, 12) highlights the advantages of the cost allocation concept approach:
>
> > *The cost allocation concept satisfies the accounting principle of matching expense and revenues. On the income statement, the inflow of resources is revenue. The outflow is expense. Using up the productive capacity of assets in an accounting period is recorded in accounting records as depreciation expense.*
> >
> > *The amount of money used to purchase the asset is the basis for the entry in accounting records. This amount is regarded as being definite and immediately determinable. The accounting objectives of verifiability and neutrality are also satisfied.* [Emphasis added]
>
> [*Depreciation Expense: A Primer for Utility Regulators*, p. 12]

[408] In 2022, the *Public Utilities Act* was amended to add s. 30(5), which directed the Board to "inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of Nova Scotia Power Incorporated used and useful in furnishing, rendering or supplying a particular service to or for the public". The Department's request that the Board exercise its authority to review the value of NS Power's assets under s. 30(2) of the *Public Utilities Act* would duplicate the proceeding recently completed under s. 30(5).

[409] In 2023, the NSUARB initiated that proceeding and engaged two consultants for this purpose. EA Technology was engaged to review NS Power's asset management processes and systems, and Doane Grant Thornton (then Grant Thornton) was engaged to review the utility's accounting policies and procedures with respect to capital assets.

[410] The NSUARB's decision in M11067 (2024 NSUARB 59) outlined how NS Power's property is valued under the *Public Utilities Act*:

> [8] Subsection 30(2) of the Act contemplates that the value of NS Power's property and assets is determined on a net book value basis. Specifically, NS Power's property and assets are valued based on their prudent original cost less accrued depreciation. Under s. 30(3) of the Act, depreciation is generally calculated on a straight-line basis.
>
> [9] The net book value of NS Power's property, plant and equipment is reported to the Board annually in the utility's regulated financial statements (e.g., M11090). In Note 1 to its 2022 financial statements in M11090, NS Power set out its accounting policies for "Property, Plant and Equipment":
>
> > **Property, Plant and Equipment**
> >
> > Property, plant and equipment ("PP&E") are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.
> >
> > The cost of additions, including betterments and replacements of units are included in "Property, plant and equipment". When units of regulated PP&E are replaced, renewed or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income.
> >
> > The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO and overhead attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance.
> >
> > Normal maintenance projects and major maintenance projects that do not increase the overall life of the related assets are expensed as incurred. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.
> >
> > Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB. The last depreciation study was completed in 2010.
> >
> > Intangible assets, which are included in "Property, plant and equipment" consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the assets in each category. The estimated service lives of intangible assets requires regulatory approval.
> >
> > [M11090, Exhibit N-1, Attachment 2, p. 13]

[411] The Board summarized the two consultants' findings as follows:

> EA Technology concluded that NS Power has good processes and systems that identify assets and groups of assets that represent the greatest risk to the organization, but that the processes and systems are typically aimed at the management of NS Power's assets rather than the management of the asset management system. It made several recommendations focused on developing a strategic asset management plan. Grant Thornton concluded, among other findings, that NS Power demonstrated "good utility practice" in its capital approval process, its policies and procedures for asset grouping and depreciation methodologies, as well as asset retirement, disposals, and not used and useful assets.
>
> [Board Decision M11067, p. 2]

[412] The Department (then the Department of Natural Resources and Renewables (NRR)) intervened in the M11067 proceeding and filed submissions on November 29, 2023. It raised no concerns about the longstanding approach to valuing NS Power's assets in that proceeding.

[413] As noted previously, when following the original cost method for valuing the utility's rate base, changes in the estimated lives of the assets over time do not result in write-ups or write-downs of the rate base value. Rather, these are reflected in a step-up or step-down of the depreciation rates used to go forward. Indeed, this was recognized by Christine Runge, Power Advisory, an expert retained by the Department (then NRR) as noted in the NSUARB's decision dealing with the approval of NS Power's DDA (2024 NSUARB 67, paras. 85-88).

[414] If the Board were to consider a departure from the widely recognized and applied original cost-based approach for valuing rate base and depreciation, it would be necessary to take this approach for all classes of property, not simply NS Power's coal assets. In such a case, it is quite possible that the current "value" of many of these assets would vary, upwards and downwards from the net-book value included in rate base. In some cases, the current "value" might even exceed the original cost. The original cost-

based approach ensures that ratepayers pay only the prudently incurred original cost of invested assets (no more, no less) used to provide service.

[415] If there was an overall net reduction in value of the entire rate base because of the change in the valuation method, it does not necessarily follow that the result would be a write-down to be absorbed by the utility. To avoid being confiscatory, and to be consistent with the underlying principle of providing utilities with the opportunity to realize a return of, and on, invested capital, if such a sudden and dramatic change in methodologies were to be made, it is likely a strong argument would exist for creating a reserve or regulatory asset for the transition.

[416] Furthermore, the timing of the change in value would need to be considered. If, for example, the value of the coal assets was not stable, but rapidly declining as 2030 approached, then the rapid decline would need to be reflected in the depreciation claimed in the test years. Depending on the extent of the decline, this could put significant upward pressure on the depreciation expense in the test years, and therefore the revenue requirement and proposed rates.

[417] The complexity and uncertainty associated with this approach would likely warrant a higher return on equity relative to the prudent original cost method.

[418] However, as discussed, this approach has been rejected in most jurisdictions in North America (if not more broadly) as being impractical and inappropriate for valuing a utility's rate base. The rate base value presented in this general rate application follows generally accepted regulatory practice and the default method explicitly referenced in the *Public Utilities Act*. The Board finds it would not be appropriate to depart from this longstanding and recognized approach.

3.6.3.1.2 Assets No Longer "Used and Useful" and the Decarbonization Deferral Account

[419] Referring to "core ideas" from the UAD line of cases and their relevance to Nova Scotia, the Department submitted, "Once an asset is no longer used and useful in providing regulated service, it can be removed from rate base, with associated losses potentially borne by shareholders". As NS Power noted in its reply submissions, this line of cases was impacted by the recent Alberta Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129. This was an appeal from an Alberta Utilities Commission (AUC) decision denying the recovery of assets destroyed in the Fort McMurray wildfire, which it made because it felt it was bound by the earlier decisions.

[420] The Alberta Court of Appeal emphasized that the *Stores Block* decision related only to the sale of assets previously included in rate base and was not directly concerned with setting just and reasonable tariffs for the utility. After reviewing the authorities, the Court stated:

> In short, the Commission erred in thinking that these earlier decisions dictated its treatment of assets stranded by unforeseen forces of nature. No binding authority compels relying on the accounting details underlying the predicted survival curves of the asset pools to decide how to deal with assets unexpectedly and permanently removed from active service by forces of nature.
>
> [para. 44]

[421] The Court of Appeal went on to find there was nothing in the relevant legislation that limited the AUC's discretion over depreciation or stranded assets. The Court summarized its findings as follows:

> Summary and Conclusion
>
> [60] To summarize, the issue is where the losses resulting from forces of nature should fall: on the utility's consumers or on the utility's shareholders:
>
> > (a) In legal terms the issue is where a just and reasonable tariff would place those losses, having due regard to the right of the utility to a reasonable opportunity to recover its prudent costs.

> (b) This issue was not decided by ***Stores Block*** or ***FortisAlberta***.
>
> (c) The analysis cannot start with an assumption that it is inherently fair to place the burden on one group or the other. That is the answer, not the premise of the question.
>
> (d) It is relevant that the utilities stopped buying insurance to save the consumers money. The Commission apparently decided that it was prudent for the consumers to self-insure.
>
> (e) The answer does not lie in whether the loss was or was not anticipated in the survivor curve behind the depreciation schedules, or whether the loss was therefore ordinary or extraordinary.
>
> (f) The answer also does not arise from "fundamental property and corporate law principles" or property ownership of the destroyed assets. Loss by fire is not a part of disposition law.
>
> Ultimately the question lies within the discretion of the Commission, to be exercised consistently with the words of the *Electric Utilities Act*, having regard to all relevant considerations, while disregarding irrelevant ones.
>
> [61] In conclusion, the decision under appeal is based on errors of law, particularly the conclusion that the Commission's options for treating destroyed assets were constrained by ***Stores Block***. The setting of rates is clearly within the discretion of the Commission, including the determination of what expenses can be included as recoverable costs and expenses, how to deal with depreciation, and how to deal with stranded or unpredictably destroyed assets. [Emphasis in original]

[422] The Court ultimately returned the matter to the AUC for redetermination following the appropriate principles. In its redetermination, the AUC reversed its earlier decision and allowed ATCO Electric to recover the net book value of the destroyed assets (Decision 28320-D01-2023, December 19, 2023).

[423] The Alberta Court of Appeal's conclusion in this recent appeal is not dissimilar to findings made by the NSUARB in the recent proceeding about the value of NS Power's property under s. 30(5) of the *Public Utilities Act*. There, as part of a discussion about the application of NS Power's Accounting Policy 6350, which deals with assets that are no longer used and useful, the Board discussed the contextual nature of the analysis:

> [47] As pointed out in the May 5, 2020, decision letter, Accounting Policy 6350 provides the Board with flexibility, on a case-by-case basis, to address the rate-base treatment of the undepreciated cost when such an application is made. The Board finds that this

> flexibility is important and can only be exercised when the full circumstances of the case are known. This could include the reasons why an asset must be retired early, along with NS Power's financial position and the existing regulatory scheme. It could also include the impact of early retirement on rates. These are the two sides of the equation the Board must weigh in the balance.
>
> [2024 NSUARB 59]

[424] When assets need to be retired to meet legislative decarbonization mandates requiring 80% of energy provided to customers be from renewable sources and the phasing out coal-fired generation by 2030, they will no longer be used and useful. However, it must be recognized that the NSUARB previously accepted the use of the DDA as the appropriate method of collecting any remaining net book value of the coal assets when they are retired in accordance with federal and provincial policy.

[425] That decision was made as an alternative to using either Accounting Policy 6350 or adjusting the depreciation rate to recover the undepreciated balance of the assets over their shorter remaining useful life (and the corresponding impact on rates that would have been occasioned as a result). In its decision approving the DDA in principle, the NSUARB noted:

> [299] In this context, NS Power is a utility regulated under a cost of service model. This means the Company is allowed to recover its prudently incurred costs in the provision of service to customers and may earn a reasonable return on its related invested capital. Therefore, where the Company has made an investment to the benefit of customers but related prudently incurred costs of capital have yet to be recovered, NS Power may recover these costs even after capital assets have been retired, in circumstances where the assets were retired due to changes in public policy beyond its control. Further, since the costs have yet to be recovered, there are still debt and equity financing costs associated with these investments. None of the parties in this proceeding have suggested that NS Power is not entitled to recover such costs.
>
> …
>
> [310] Based on the above, the Board finds that the proposed DDA provides a mechanism that will allow better flexibility in the recovery of investment in thermal assets that will be phased out due to the decarbonization transition. It will also effectively balance timely recovery of the related costs with customer affordability. The Board also notes that the DDA is not intended to make unrecoverable costs recoverable by NS Power. Instead, it will allow for NS Power's recovery of prudently incurred costs while making the transition to increased renewables to 2030 and beyond more affordable for customers.
>
> [2023 NSUARB 12]

[426] The decision strikes a balance between affordability for customers and the utility's entitlement to an opportunity to recover its prudently incurred costs and a fair return. In making that determination, the NSUARB considered both immediate and long-term impacts on customers. Accelerating the recovery of the net book value and decommissioning costs over the remaining life of these assets would have caused rates to sharply increase, negatively affecting customers. At the same time, holding depreciation rates and forcing NS Power to absorb a significant write-off of the value of the coal assets when they are no longer used and useful could very likely have a material negative financial impact on the financial health of NS Power. As was noted and discussed in the NSUARB's decision in the previous general rate application, negative financial impacts on the utility ultimately cost customers in the form of higher interest costs and reduced ability to raise capital.

[427] This decision was recently mentioned in Deirdre Sheehan et al, *The Push for Electrification and a Net-Zero Grid: Developments, Reactions, and Implications,* 2024 62-2 Alberta Law Review 424, 2024 CanLII Docs 3091:

> Consideration of the retirement of coal-fired assets in Nova Scotia by the Nova Scotia Utility and Review Board (NSURB) is illustrative of the potential rate implications of early asset retirement. NS Power expects it will have to retire coal-fired assets and associated infrastructure by 2030 due to its legal decarbonization obligations, prior to fully recovering its investment in these assets or its decommission costs in rates. The undepreciated costs associated with these early retirements "may be as much as $757 million." Seeking approval to accelerate the recovery of depreciation expense (that is, recovery of its remaining capital investment) and decommissioning costs over the years of operation remaining to 2030 "would cause a substantial increase in rates." Therefore, NS Power proposed, and NSURB approved with some changes, the transfer of these costs to a regulatory asset account — the Decarbonization Deferral Account (DDA) — to facilitate rate stability and affordability for customers. NSURB found that the transfer of the costs to the DDA would allow flexibility around the timing of the recovery of the costs, and stated:
>
> > To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.

> As is evident from the foregoing, absent government funding and in the pursuit of affordability, regulators may need to consider novel and flexible approaches to address the financial impacts of early retirements and other energy transition costs while ensuring utilities have an opportunity to recover the return of and on their investments.
>
> [pp. 453-454]

[428] Confirming the utility's entitlement to recover its undepreciated costs through the DDA is consistent with longstanding Canadian regulatory principles and practices, including those described in the recent Alberta Court of Appeal decision. The NSUARB determined that the DDA was the most appropriate approach in the circumstances presented by the need to transition to decarbonized energy systems, consistent with federal and provincial government policies and legislation. There is no basis to revisit that decision.

3.6.3.1.3 The Requirement for Prudence

[429] Prudence is, of course, always a consideration. The language used in s. 30(2) of the *Public Utilities Act* is not simply "original cost" but "prudent original cost". A utility is entitled to the opportunity to recover its prudently incurred costs. That is, costs incurred under a standard of care that a reasonable person would expect to be made by other similarly situated utilities in the same circumstances encountered by the utility at the time decisions had to be made.

[430] The Board's approach to prudence was recently canvassed in its decision in NS Power's most recent fuel adjustment mechanism audit (2025 NSEB 10, paras. 17-49). Useful principles were helpfully outlined by the Industrial Group in its submissions in that matter, which were referenced in the decision:

> [18] The Industrial Group's closing submissions in this proceeding listed the following principles about the prudence of utility expenses, which it extracted from the legislation and case law:
>
> > 1. The Board may allow the utility's expenses which are "reasonable and prudent and properly chargeable."

> 2. NSPI benefits from an initial presumption that its decisions are prudent.
>
> 3. The presumption of prudence is rebutted when questions are raised. This is the first stage. Hindsight may be used at this stage.
>
> 4. When prudency has been called into question, NSPI must discharge its burden to satisfy the Board that it applied a reasonable standard of care in its decision-making and actions, and that its expenses were reasonable and prudent based on information known or ought to have been known at the time. This is the second stage. Hindsight may not be used at this stage.
>
> 5. If a finding of imprudence is made, the Board may disallow costs which have been imprudently incurred. [Footnotes omitted]
>
> [Industrial Group, Closing Submissions, pp. 2-3]

> [19] The Board finds this to be a helpful summary. In this case, there did not appear to be significant disagreement over these principles (except for the use of hindsight to rebut the presumption of prudence). There was considerable disagreement about how these principles applied in the context of a FAM Audit. Positions differed on the threshold for rebutting the presumption of prudence. The parties also debated when human error might amount to imprudence.

[431] The Board went on to find:

> [42] In summary, the Board finds that the threshold for rebutting the presumption of prudence is contextual. It requires a reasonable question – something that is more than a bald statement or speculation – but it should not be too onerous and may arise in hindsight. In the context of a FAM Audit, the audit report may provide context but does not increase the threshold for rebutting the presumption or reverse the onus. Questions raised in the FAM Audit may rebut the presumption of prudence. The audit report is also available as evidence to assess the ultimate issue of prudence (although hindsight may not be used in this stage of the assessment).

[432] In its closing submissions in the current matter, the Department suggests two areas where NS Power's prudence may be questioned. The first is that depreciation rates were too low, resulting in present net book values for retiring coal assets to be recovered from customers that are higher than they should have been. The second, is that NS Power unnecessarily invested in these assets in the face of impending retirements.

[433] As discussed previously in this decision, the last depreciation study presented to the regulator before the one in this proceeding was filed with the NSUARB in 2010. The depreciation rates NS Power originally sought in that application were higher

than those eventually accepted by the NSUARB. These were reduced in a “black box” settlement following the filing of evidence by experts suggesting they were too high and that some asset lives were too short. In its closing submissions, the Department recognized that the impact of the settlement agreement in Matter M03665 kept customer rates lower in the near term. As that proceeding was not a general rate application, the depreciation rates could not be immediately implemented. They were implemented in NS Power’s next general rate application, which was filed in 2011, and a decision was rendered in December 2012. The decision in that matter also accepted a settlement agreement signed by a number of intervenors.

[434] NS Power’s next general rate application was filed in January 2022. In that matter, NS Power failed to file an updated depreciation study, as the Board would have expected, but NS Power recognized that the requirement to close coal plants by 2030 challenged the recovery of undepreciated costs relating to those assets and proposed the DDA, as discussed previously in this decision.

[435] A subsequent proceeding to formally approve the DDA was initiated by NS Power. Several parties in that proceeding argued that the costs to be transferred into the DDA should be reviewed. However, none of them, including the Department (then NRR) who retained an expert to file evidence in that proceeding, suggested that the amount should be reduced because of imprudently charged depreciation rates.

[436] Regarding the issue of improper investment in the face of impending coal plant closures, the Department’s expert in the DDA matter supported NS Power’s recovery of the cost of the coal generation assets but recommended that NS Power be

allowed to recover the unamortized balances of the coal assets only where the Board has determined those costs have been prudently incurred:

> [57] Ms. Runge supports NS Power's recovery of its prudently incurred investments in its coal generation assets:
>
> > 75. The no hindsight principle should always be applied in the assessment of the return of capital to a utility. If the investment was considered prudent at the time it was made with all reasonably available knowledge applied to that assessment, then the utility should not be at risk for the recovery of those costs.
> >
> > 76. The end goal of the regulatory compact is to be fair to both the utility and the rate payers, where one party has an obligation to serve and minimum reliability standards to uphold and the other is held captive given inelastic consumer demand and monopoly utility supply. Application of the no hindsight principle to return of capital is fair to both parties. The coal generation assets were built for rate payers. At the time they were built, they were considered to be prudent. Rate payers wanted access to cost-effective electricity, which was provided to them, and NSPI had an expectation that in exchange for building long-life assets to provide that electricity, it would recover those prudently invested costs over the life of the assets.
> >
> > 77. Consistent application of the no hindsight principle to the return of capital also benefits both parties over the long run. The utility benefits from certainty of cost recovery associated with investment choices that were considered prudent at the time they were made, with no risk that costs will later be removed from rate base due to changes in government policy or technological advancements that occur. At the same time, rate payers benefit as the result is significantly lower utility risk than the application of the used and useful principle to the return of capital, which allows for a lower ROE and potentially a lower cost of debt than would be the case under a policy focused on the used and useful test. In the long run, the application of a lower ROE to the totality of a utility's rate base can be more beneficial to rate payers than small costs that may otherwise be removed from rate base from time to time due to early retirements.
> >
> > [Exhibit N-10, p. 23]

[58] She goes on to say that this only applies to costs determined to have been prudently incurred. It notes that not all costs incurred by NS Power are subject to an explicit prudence review when they are incurred and highlights the importance of such reviews to ensure that the utility is making only proper investments and not adding to its rate base to inappropriately increase its return:

> > 79. The prudency test is an important part of the regulatory compact. Due to the fact that a utility is a natural monopoly provider of service, if the utility established its own pricing in the absence of a regulator, the utility would have the ability to charge rates that include significant rents as a result of its market power in the region and high consumer demand for its product. Regulatory proceedings that test the proposed investments of a utility allow for rates that are more reflective of competitive market pricing instead of this monopolistic pricing. Given that the ROE is established in a

> regulatory proceeding and that in the case of NSPI there is no ability to earn above the approved ROE by more than 0.25%, the means by which NSPI increases its profitability is to invest in capital and increase its rate base. Accordingly, the utility has an incentive to over-invest in capital if it can get those costs approved and added to rate base. Continued testing of costs to ensure prudence of investments is, therefore, required in order to ensure just and reasonable rates.
>
> [Exhibit N-10, p. 24]

> [59] Ms. Runge recommends that NS Power be allowed to fully recover the unamortized balances associated with the early retirement of its coal assets where the Board has determined those costs to have been prudently incurred. However, she submitted that, before adding them to the DDA, the Board should evaluate the prudence of any costs NS Power proposes to transfer to the DDA that have not already been found by the Board to have been prudently incurred. Ms. Runge said NS Power should apply to the Board for this purpose when it wants to add such costs to the DDA. [Emphasis added]
>
> [2024 NSUARB 67]

[437] In its decision, the NSUARB referenced the general principles it applied to prudence questions, noting the general presumption of prudence and that it was open for parties to raise questions of imprudence. In respect of the concern about sustaining capital, the NSUARB noted:

> [72] Some parties expressed concerns about future sustaining capital and decommissioning costs. Costs of this nature may exceed the $1,000,000 threshold, providing parties with an opportunity to question their legitimacy in future capital approval applications, before they are incurred. The Board expects these concerns will be advanced and assessed in the context of the applications for these specific investments. To ensure that the Board's processes appropriately allow for such participation, particularly if the requested capital approval is not included in an approval requested in an ACE plan proceeding, the Board directs NS Power to provide specific notice to all participants in this proceeding upon filing any future capital work order applications involving assets that are forecasted to be included in the DDA and to confirm this was done in its applications to the Board.
>
> [73] The Board also notes that NS Power said the Board may choose to review costs transferred to the DDA in any given year:
>
> > … The reporting requirements outlined in the DDA Manual are intended to provide all stakeholders with transparency around transfers to or from the DDA in any given year and the Board may choose to review any of these transfers.
> >
> > [NS Power Reply to Closing Submissions, p. 5]
>
> [74] Based on this, it is possible that circumstances may arise that make it appropriate to consider the prudence of costs transferred at that time. However, as noted above, the Board has found that making the transfer of costs to the DDA dependent on mandatory applications to determine their prudency (where this has not already been determined) is not consistent with the capital approval provisions in the *Public Utilities Act*. Likewise, NS Power should understand that the Board's acceptance of any DDA reports filed following

> the processes outlined in the proposed DDA Manual would also not constitute a finding that the costs included in the report were prudent.
>
> [2024 NSUARB 67]

[438] In short, it remains open for the Department or other parties to challenge the prudence of any of NS Power's expenditures, but these are presumed prudent and there is a threshold that must be met to rebut this presumption. The Department filed no evidence in the current GRA proceeding, did not explore questions of prudence in any cross-examination, and only raised these issues in closing submissions. Additionally, the allegation of imprudent investment was only raised in a very general way. While the issue about depreciation rates was somewhat more specific, it was still quite general and also failed to address the impact of the equivalency agreements between the Province of Nova Scotia and the Government of Canada. Therefore, the Board finds that the threshold for rebutting the presumption of prudence has not been met in this proceeding.

3.6.4 Findings

[439] The Board accepts NS Power's forecasted average rate base of $5.58 billion in 2026 and $5.89 billion in 2027.

3.7 Return on Equity and Capital Structure

[440] NS Power's existing rates are set based on a current capital structure that includes 40% equity and 60% debt, with an approved return on equity of 9%. Under the current framework, NS Power may realize an annual return on equity up to 9.25% and must return any earnings above 9.25% to its customers.

[441] In this proceeding, NS Power proposed to continue to set rates based on a 9% return on equity within a range from 8.75% to 9.25%. NS Power also requested to maintain its debt-to-equity ratio, for rate-setting purposes.

3.7.1 The Fair Return Requirement

[442] NS Power operates as a natural monopoly in Nova Scotia, where the absence of meaningful competition means the competitive forces of the market do not apply. Section 45 of the *Public Utilities Act* entitles a public utility to earn a just and reasonable return on its rate base, in addition to recovering its reasonable operating expenses and other just allowances. As a result, it is the Board's responsibility to set the parameters under which the utility may earn a return from its customers.

[443] A fair return is fundamental to ensuring the utility's ongoing financial stability. Because NS Power must secure external capital to undertake necessary investments, it requires a return sufficient to attract and retain investors. If the approved return is set below levels commensurate with the utility's risk, investor confidence may erode, which could affect NS Power's access to capital on reasonable terms and could place downward pressure on its credit rating. A weak credit rating increases borrowing costs and, therefore, raises the costs paid by customers. The company could even lose access to certain debt markets altogether, with more significant cost implications for NS Power and its customers.

[444] There is a well-recognized and long-standing legal standard the Board must follow when approving a utility's return on its invested capital. A century ago, the Supreme Court of Canada described the test as follows:

> 18 The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. … [Emphasis added]
>
> [*Northwestern Utilities Ltd. v Edmonton (City)*, [1929] SCR 186]

[445] This test was more recently accepted by the Supreme Court of Canada in *Ontario (Energy Board) v Ontario Power Generation Inc.*, 2015 SCC 44:

> 15 This Court has had the occasion to consider the meaning of similar statutory language in *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.). In that case, the Court held that "fair and reasonable" rates were those "which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested" (pp. 192-93).
>
> 16 This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.). [Emphasis added]

[446] The latter part of this passage endorsed the Federal Court of Appeal's comments in *TransCanada Pipelines Ltd. v Canada (National Energy Board)*, 2004 FCA 149, where that court said:

> 12 Even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the Board does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.
>
> 13 In the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain existing ones. Eventually, it will go out of business. This will harm not only its shareholders, but also the customers it will no longer be able to service. The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service. [Emphasis added]

[447] The Federal Court of Appeal also addressed a concern raised by TransCanada Pipelines that the National Energy Board set its return on equity too low because it improperly considered the impact that higher rates would have on TransCanada's customers. Although the court found the evidence did not support the conclusion that the National Energy Board had suppressed the return on equity because

of the resulting impact on customers, it accepted the impact of the return on customers was not a relevant factor under the *Northwestern Utilities* test:

> 35 In oral argument, the appellant conceded that it does not object to its customers having input into the Board's cost determinations and in particular, its cost of capital determination, provided the issues in dispute are restricted to the costs of the Mainline. However, the appellant does object to the Board taking the impact of tolls on customers and consumers into account in determining the Mainline's cost of equity capital. The appellant says that the required rate of return on equity must be determined solely on the basis of the Mainline's cost of equity capital. The impact of any resulting toll increases on customers or consumers is an irrelevant consideration in that determination. The appellant does concede that when the final tolls are being fixed, the impact on the customers and consumers may be relevant, but insists that it is irrelevant when determining the required return on equity.
>
> 36 I think that this argument is sound and in keeping with the decision of the Supreme Court in *Northwestern Utilities*. The cost of equity capital does not change because allowing the Mainline to recover it would cause an increase in tolls. Under the Board's Equity risk premium methodology, the cost of equity capital is driven by the Board's estimate of the risk-free interest rate and the degree of risk investors perceive in the "benchmark" pipeline. The higher the risk, the higher their required rate of return. The degree of risk specific to the Mainline is accounted for by adjustments to its deemed capital structure. Accordingly, the cost to the Mainline of providing that rate of return on the equity component of its deemed capital structure is unaffected by the impact of tolls on customers or consumers. [Emphasis added]

[448] The Federal Court of Appeal went on to say that although the impact on customers cannot be a factor in determining the utility's entitlement to a specific return on equity, any resulting increase in tolls may be a factor in determining the way the utility may be able to recover its costs. In particular, the court said if an increase would be so significant it would lead to "rate shock" if implemented all at once, rate increases could be phased in over time, "provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring recovery of its cost of capital" (para. 43).

[449] In a similar vein, a recent Ontario Energy Board decision noted that ensuring the utility has the necessary financing to carry out its operations must be the focus when setting a return on equity. The setting of the return on equity is not a tool to "balance" competing interests between the utility and its customers:

> The OEB affirms that in setting this important component of the determination of the cost of capital for regulated utilities it adopts the requirements of the [fair return standard], as set out in the 2009 Report. These requirements mandate a regulatory return that meets the market expectations derived from the review of comparable investments, ensures the financial integrity of the subject utilities and allows for compliance with the capital attraction standard: the approved return must permit incremental capital to be attracted to the enterprise on reasonable terms and conditions. The [fair return standard] does not involve the balancing of interests between the utility and its customers but is singularly focused on ensuring that a utility is furnished with the necessary financing to carry out its responsibilities of service to its customers. However, the utility is allowed the opportunity to earn its cost of capital, no more and no less. [Footnotes omitted] [Emphasis added]
>
> [OEB EB-2024-0063, p. 34]

[450] In *Energy Law and Policy* (Kaiser and Heggie, ed., 2011), Canadian authors, Gordon Kaiser and Bob Heggie, summarized the principles considered by regulators to set fair returns:

> While no legislative guidance is provided as to what a regulator is to take into account in determining a fair return, United States and Canadian courts have considered the issue. The courts have listed factors that tribunals should consider, but have not prescribed methods for calculating a fair return. To be considered fair, tribunals have taken the following principles or standards into account in determining returns:
>
> - The return must be comparable to the return available in the market on an investment of similar risk: the comparable investment or earning principle.
>
> - The return must be sufficient to attract new utility capital investment: the capital attraction principle.
>
> - The return must be sufficient to maintain the financial integrity of the utility: the financial integrity principle.
>
> The comparable investment principle is based on the idea that in order to be fair to a utility equity investor, the investor must be satisfied that the potential return on the investment is sufficient to compensate for the risk assumed in relation to the entire spectrum of comparable competitive investments available. The challenge with this principle is finding comparable companies with similar risks.
>
> The financial integrity and capital attraction principles are more straightforward and generally will be satisfied if the comparable investment principle is met. Financial integrity is satisfied if the combined effect of the allowed return and the equity thickness of a utility's capital structure results in a debt coverage ratio sufficient to support stable investment grade ratings.
>
> Debt investors need earnings to provide security for the debt capital invested. The difficulty with this principle is determining whether a particular desired rating should drive the allowed return.

> Capital attraction means that returns must be adequate to attract necessary capital on reasonable terms to build required utility infrastructure.
>
> [Energy Law and Policy, pp. 188-189]

[451] Similar principles are considered by utility regulators in the United States: *Bluefield Waterworks & Improvements Co. v Public Service Commission of West Virginia* (1923), 262 US 679 (US W. Va.) and *Federal Power Commission v Hope Natural Gas Co.* (1944), 320 US 591 (US Sup Ct.). In *Re Nova Scotia Power Inc.*, 2019 NSUARB 165, the NSUARB referenced *Northwestern Utilities*, *Bluefield* and *Hope* as "landmark decisions which set out general principles with respect to rate of return".

[452] The assessment of these principles in any matter before the Board is based on the evidence presented. In the current case, due to NS Power and customer representatives reaching a consensus agreement in advance of the general rate application, only two parties presented the Board with expert evidence, NS Power and Board Counsel.

3.7.2 Overview of Cost of Capital Evidence

3.7.2.1 Return on Equity

[453] Determining a fair return on equity generally entails the use of several well-established financial models. These include, but are not limited to, the discounted cash flow (DCF) model; the capital asset pricing model (CAPM) and the risk premium model. In practice, common approaches assess prevailing conditions in the capital markets and often validate conclusions through the application of multiple models to ensure consistency and robustness.

[454] Under the consensus agreement, the signatories agreed to a return on equity for NS Power of 9% for rate setting purposes, with an earnings band of 8.75% to

9.25%. They also agreed that an equity thickness of 40% for rate setting purposes would be retained.

[455] NS Power presented evidence from its cost of capital expert witnesses James Coyne and John Trogonoski of Concentric Energy Advisors (Concentric). Concentric reviewed the economic and financial market conditions in Canada and the United States (U.S.) to inform how those conditions affect a utility's return on equity. Concentric noted that the risk to a company's earnings is a function of its business and financial risk. Utilities obtain debt and equity in capital markets that are affected by macroeconomic indicators and central bank policies. Concentric's evidence filed with NS Power's application used market data as recent as February 2025.

[456] Concentric believes that since the interest rates on government and utility bonds have been stable since NS Power's last GRA, the cost of utility capital has been stable. However, over the long-term, Concentric expects the electric utility industry to experience structural challenges associated with climate change, cybersecurity, grid improvements and customer preferences. Therefore, Concentric says NS Power requires a return on equity that is competitive enough to attract the investment it will need to support its own energy transition.

[457] To determine a suitable return on equity for NS Power, Concentric created proxy groups of companies it considered to be comparable to NS Power in terms of business and financial characteristics. Concentric regards the nature of the financial markets in the U.S. and Canada as integrated and utility regulatory systems as similar. In total, Concentric created 3 proxy groups: a group of 5 Canadian electric utilities; a group of 10 U.S. electric utilities; and a North American group consisting of 10 U.S. proxies and

3 Canadian proxies. Its return on equity recommendations are based on its North American proxy group.

[458] Based on the average return on equity results from its DCF, CAPM and risk premium models, Concentric recommended a return on equity for NS Power of 9.9%. This is higher than the return on equity proposed under the settlement agreement, but Concentric believes this to be a reasonable return on equity for NS Power. Concentric's recommendation incorporated an adjustment for flotation costs and financing flexibility of +50 basis points, or +0.5%. Concentric made this adjustment in its DCF and CAPM models to reflect costs associated with the sale of new issues of common equity.

[459] Concentric evaluated NS Power's return on equity using current and forecast economic conditions for Canada and the United States. However, it conducted its analysis early in 2025, a year in which tariff threats and uncertainties escalated globally with geopolitical tensions testing longstanding trade relationships leading to market turmoil and repeated changes to economists' forecasts. As NS Power did not file its application until September of 2025 and the hearing was held in January 2026, some of the information used in Concentric's analysis was stale.

[460] In response to Undertaking U-14 [Exhibit N-81], Concentric updated its return on equity analysis using market data as of December 31, 2025. Based on this data, the average return on equity of the three models for Concentric's North American proxy group fell from 9.90% to 9.43%. NS Power suggested this result was due to a significant drop in utility beta values during 2025, along with a smaller reduction in Canada's forecasted GDP growth. Higher forecasted long-term government bond yields partially offset these effects.

[461] Board Counsel consultant, Dr. Cleary, was the only expert witness to provide an alternative cost of capital review. Dr. Cleary presented evidence that equity returns allowed by regulators in Canada and the U.S. have not declined in the past two decades. He believes, however, that these returns should have declined, with reductions in government and utility bond yields. He also believes that Canadian and U.S. utilities are earning excess compensation relative to their actual market-determined cost of equity. He highlighted that there is general market acceptance that utility companies are less risky than the average publicly traded company, which implies expected returns should be less than that of an average risk company.

[462] Dr. Cleary reviewed the economic and financial market conditions in Canada and the U.S., but he focused his analysis on Canadian data and forecasts. Dr. Cleary argued against using U.S. utilities as proxies for NS Power because he does not consider them to be reasonable comparators for Canadian utilities. He argued, in part, that U.S. utilities are higher risk than Canadian utilities because they are typically holding companies, they operate in the U.S. and the nature of their operations entails more risk. He did not agree that Concentric's North American proxy group was an appropriate comparator group for NS Power because he viewed the U.S. companies that made up most of this proxy group as having significantly higher average risk.

[463] Dr. Cleary supported his position that U.S. utilities were, on average, riskier than Canadian utilities with an examination of utility betas. Betas measure the volatility of a company's stock compared to the overall return in the market. He said this analysis demonstrated that, over a lengthy period, U.S. utility betas are much higher than Canadian utility betas.

[464] NSP Maritime Link's 2026 annual assessment (Matter M12394) included evidence provided by Dr. Cleary and Concentric that was similar to what they filed in this proceeding. During his testimony in that matter, Dr. Cleary also explained that Canadian institutional and fixed income investors exhibit a home-country bias, influenced in part by comparatively higher U.S. payout structures and exposure to foreign exchange risk.

[465] Dr. Cleary further noted that, following the 2024 U.S. Presidential election, economic and political developments have contributed to a divergence in the previously aligned economic relationship between the U.S. and Canada, with the potential to become more disconnected.

[466] Dr. Cleary recommended a 7.6% return on equity for NS Power based on his financial modeling using CAPM, DCF and risk premium models. Like Concentric, he included an adjustment for flotation costs of 50 basis points or 0.5%.

[467] A summary of the results derived from Concentric's and Dr. Cleary's return on equity evidence is set out in the table below, with the numbers for Concentric taken from its response to Undertaking U-14:

Summary of Return on Equity Results				
	CAPM	DCF	Risk Premium	Opinion
Concentric	9.23%	9.02%	10.04%	9.43%
Cleary	6.84%	7.86%	7.94%	7.6%

3.7.2.2 Capital Structure (Equity Ratios)

[468] Concentric determined that a common equity ratio of 45% would be appropriate for NS Power. Concentric considers the requested common equity ratio of 40% (per the settlement agreement) to be conservative given NS Power's financial and business risks from owning generation assets and a requirement to accelerate the retirement of much of its thermal generation by 2030. NS Power's request to maintain its

40% equity ratio leaves it similarly situated to other Canadian utilities but lower than American integrated electric utilities, based on Concentric's comparison of equity ratios of other electric utilities (reproduced below):

Figure 30: Authorized Electric ROEs and Equity Ratios

	Generation	ROE	Equity Ratio
NSPI (existing)	Yes	9.00%	40.0%
NSPI (Concentric analysis)	Yes	9.90%	45.0%
NSPI (proposed)	Yes	9.00%	40.0%
Newfoundland Power	Minimal	8.60%	45.0%
Maritime Electric Company Ltd	Minimal	9.35%	40.0%
Ontario Electric Utilities	None	9.00%	40.0%
Alberta Electric Utilities	None	8.97%	37.0%
FortisBC Inc.	Yes	9.65%	41.0%
Canadian Electric Average		**9.11%**	**40.6%**
U.S. Electric Utilities[59]	Yes	9.79%	52.0%
U.S. Electric Proxy Group Average[60]	Yes	9.66%	51.1%

[Exhibit N-8, Appendix 10A, p. 57 of 87]

[469] Dr. Cleary supported NS Power's requested 40% equity ratio, stating it is reasonable given its lower debt rating of BBB- and because NS Power holds a higher percentage of generation assets compared to other Canadian utilities.

3.7.3 Return on Equity Modeling

[470] In the discussion that follows, references to results from Concentric's analysis are to the update it provided in Undertaking U-14 using the analysis as generally described in its original report [Exhibit N-8, Appendix 10A] for its North American proxy group.

3.7.3.1 CAPM Models

[471] The CAPM accounts for the risk of common equity relative to risk free securities such as government bonds. The CAPM model estimates the required return of a security based on the relationship between the expected return of the market and the

systematic risk of the security. The main components of the CAPM model include the risk-free rate of return, the market risk premium and company betas.

[472] The market risk premium is measured as the difference between the expected return of the market and the risk-free rate. It represents the rate of return over and above the risk-free rate. The expected return of the market is a long-term assumption about how the market will perform over time. The risk-free rate is typically represented by the long-term government bond rate. As discussed previously, beta is a measure of a stock's risk and is measured by the changes in its price relative to changes in the overall market.

[473] Based on its assessment of its North American proxy group and adjusting for flotation costs, Concentric determined that a return on equity of 9.23% was appropriate under its CAPM analysis. Dr. Cleary estimates a 6.84% return on equity under his CAPM assessment, with adjustments.

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[474] A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	CAPM	
	Concentric	**Cleary**
Risk-free Rate	**3.87% (Canada)** **4.56% (U.S.)** *[Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]*	**3.66%** *[Long-term government yield of 3.66% as of November 20, 2025]*
Market Risk Premium	5.75% (Canada) 7.31% (U.S.) **6.53% (Average)** *[Kroll]*	**5.5%** *[Within historical range of 4-6%]*
Beta	**0.66 (mean)** *[Bloomberg and Value Line]*	**0.45** *[Usual point within historical range of 0.30-0.60]*
Average Yield Spread Adjustment		**-0.15%**
Debt Cost Spread		**0.35%**
Financial Flexibility	**0.50%**	**0.50%**
ROE	**9.23%**	**6.84%**

[475] For the risk-free rate of return, Concentric uses *Consensus Economics* forecasted 10-year government bond yield plus the average ten-year historical spread between the 10-year and 30-year government bonds (Canada, 3.87%; U.S., 4.56%). Dr. Cleary estimates CAPM using the actual yield on long-term government bonds at a recent point in time for his risk-free rate. In this case, he used the long-term government yield of 3.66% as of November 20, 2025.

[476] Concentric's risk-free rates are higher, particularly for the U.S. In his evidence, Dr. Cleary argued that using Consensus yield forecasts as a proxy for future 30-year Canada yields has led to an upward bias relative to the subsequent actual yields that prevail. Dr. Cleary also criticized Concentric's derivation of 30-year bond yields. The

use of spreads to adjust 10-year bond yields to 30-year bond yields introduces further assumptions and sources for error.

[477] Concentric estimated the historical market risk premium based on the arithmetic mean of the equity market returns for large company stocks minus the income only return (i.e., the bond coupon rate) on long-term government bonds using data from Kroll, LLC. The market risk premium for Canada is based on returns from 1919-2023 (5.75%) and, for the U.S., on returns from 1926-2023 (7.31%).

[478] Concentric averaged the market risk premiums for Canada and the U.S. (6.53%) and applied the average to all proxies, irrespective of the country. Concentric regarded the market risk premiums in Canada and the U.S. as highly correlated, although there was significant disagreement from Dr. Cleary throughout his evidence about the inclusion of U.S. proxies.

[479] Dr. Cleary suggests that market risk premiums lie within a “commonly used 4-6% range”. He cites academic studies to support this view. Dr. Cleary notes that A-rated Canadian utility bond yield spreads were well below their long-term average, indicating a low-risk environment that would normally lead him to use a market risk premium of 4.5% or 5%. However, citing uncertainties due to global trade tensions, which pose a risk to future economic growth, he settled on a market risk premium of 5.5%.

[480] Concentric’s market risk premium is higher than Dr. Cleary’s. Dr. Cleary attributed this to the use of U.S. data. He also noted that Concentric’s market risk premium estimates use income only returns for bonds rather than total returns, which neglects to account for both the interest and capital gains (or losses).

[481] Concentric sourced adjusted betas from Value Line and Bloomberg. These are raw betas that have been adjusted on the theory that there is a tendency for betas to revert towards the market mean of 1.0 over time and a need to account for errors associated with statistical estimates. Concentric's position is that raw betas are inferior inputs because they do not represent the expected returns or the average market returns. It said that the CAPM is a forward-looking model, therefore a forecasted beta and its tendency to perform at the average of the market over time is not limited by the historical performance of the industry beta.

[482] Dr. Cleary reviewed beta estimates in his evidence and arrived at several conclusions about appropriate beta estimates. Based on his assessment of research conducted in other cases and academic study, Dr. Cleary says that U.S. utility beta estimates are higher than those for Canadian utilities and should not be used. He submits that Canadian utility beta estimates have historically averaged between 0.2 and 0.4 (with 0.35 being the "best estimate"). He said Canadian utility beta estimates have never come close to 1.0, with maximum values being in the 0.6-0.8 range; therefore, he considered the use of "traditional adjusted betas to be totally inappropriate". He submitted that, based on historical evidence, a range of reasonable estimates for betas was between 0.3 and 0.6.

[483] Dr. Cleary noted that he has used a beta of 0.45 "in several previous utility proceedings" and that is his assessment in this proceeding as well. Although Dr. Cleary noted that beta estimates for companies can change dramatically through time, he said this demonstrated why it was appropriate to reference long-term averages and use judgement to determine the best estimates of future betas.

[484] As with the other parameters in the model, Concentric's beta estimate was higher than Dr. Cleary's. While Dr. Cleary applied his "usual" 0.45 beta, Concentric used company specific adjusted betas from Bloomberg and Value Line. These varied, but all were above Dr. Cleary's estimate. Of note, the Canadian companies in his North American proxy group had the lowest values. The mean value of all betas in the proxy group was 0.66, somewhat above Dr. Cleary's range of reasonable estimates.

[485] In addition to the adjustment for flotation costs and financing flexibility that both he and Concentric made, Dr. Cleary made other adjustments. First, he explained that government bond yields have increased recently but are still low. He said A-rated Canadian utility bond yield spreads have increased but are less than the long-term average spread. He noted that the Bank of Canada indicated that the increased spread is due to liquidity problems, but some of it still reflects increased risk premiums for low-risk firms, like utilities. He made a downward adjustment of -0.15% to account for the time varying risk premium. Second, Dr. Cleary also remarked that NS Power is paying 0.35% more on its long-term debt than the average Canadian utility. He applied this spread to adjust his CAPM estimates upward.

3.7.3.2 DCF Models

[486] The DCF model infers the required rate of return by replicating the actions of an investor in valuing the firm's securities by estimating the dividend yield and future growth rate.

[487] Based on its assessment of its North American proxy group and adjusting for flotation costs, Concentric determined that a return on equity of 9.02% was appropriate under its DCF analysis. Dr. Cleary estimated a 7.86% return on equity under his DCF (DDM) assessment, with adjustments.

[488] A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	DCF	
	Concentric	**Cleary**
Dividend Yield	**3.49%** *[Calculated from Bloomberg]*	**5.29%** *[Calculated from Morningstar]*
Multi-Stage Growth Rate Years 1-5	**6.62% (Mean)** *[Zacks, SNL Financial, Value Line, Seeking Alpha]*	
Multi-Stage GDP Growth (pertetuity)	**3.84% (Canada)** **4.24% (U.S.)** *[Consensus Economics]*	
DDM Sustainable Growth Rate		**1.64%** *[Calculated from Morningstar]*
Debt Cost Spread		**0.35%**
Financial Flexibility	**0.50%**	**0.50%**
ROE	**9.02%**	**7.86%**

[489] Concentric's multi-stage DCF model uses three phases of growth: near-term, reflecting the initial 5-year period; transitional growth, years 6 to 10; and long-term growth, years 11 and beyond. The near-term growth rates are based on analysts' earnings per share growth forecasts for each company in the proxy group (6.62% (mean)). Concentric's long-term growth rates are based on forecasted real GDP growth plus inflation (Canada, 3.84%; U.S., 4.24%). The medium term or transitional growth rates are pro-rated in a linear fashion.

[490] Dr. Cleary expressed concerns about Concentric's DCF model, noting its reliance on short-term earnings per share growth based on sell-side analysts' forecasts, rather than buy-side. He observed that the sell-side forecasts are typically upwardly biased and exceed nominal GDP growth rates as used in the final stage of the model. He

further stated in his evidence that using nominal GDP as a long-term growth assumption is overly optimistic for a low-risk utility, and that Concentric's model effectively assumes dividend growth above GDP for 10 years, before converging to nominal GDP thereafter.

[491] In its report, Concentric anticipated these criticisms. Concentric emphasized its use of multiple sources of earnings growth, which it says best informs the overall estimate, enhances its model and reduces the chance for arbitrary adjustments and custom calculations. Based on an historical analysis, Concentric submitted that both earnings and dividend growth have exceeded GDP growth, so analyst growth estimates should not be presumed to be upwardly biased just because they are higher than GDP growth.

[492] Using dividend yields for the companies in the proxy group (3.49% (mean)), Concentric's result was a return on equity of 9.02% after flotation costs.

[493] Dr. Cleary applied a Dividend Discount Model (DDM), which is a variation of the constant growth DCF model that assumes the market price of a stock is equal to the present value of expected future cash flows (dividends paid per share) that equity holders expect to receive. To begin his analysis, Dr. Cleary calculated the implied rate of return for the overall market and then applied the model at the industry level using values he considered to be representative of publicly traded utilities in Canada.

[494] To determine the overall return for the market in his DDM model, he uses the average real GDP growth rate from 1992 to 2024 and various estimates of forecasted GDP growth rates in 2025 and 2026. He then adds the target inflation rate to arrive at a nominal GDP estimate (3.8%). Dr. Cleary then inputs the dividend yield for the S&P/TSX

as of December 31, 2024, (2.83%) to derive an implied equity return for the market as a whole for 2024 (6.74%).

[495] Dr. Cleary notes that a limitation of the single-stage growth model he uses is the assumption of constant growth in dividends to infinity. He said this limitation may be overcome by using a multi-stage version of the DDM called the H-Model, which assumes that growth in dividends moves in linear fashion from some current short-term growth rate toward some long-term growth rate over a specified period of time. Applying this model, he uses the 2025-2026 nominal growth rate for the short term (3.2%) and the average nominal GDP growth rate from 1992 to 2024 (4.3%) to derive a market return of 7.19%.

[496] Dr. Cleary then applies his DCF (DDM) model to sample Canadian utilities using each company's sustainable growth rate by multiplying the earnings retention ratio by return on equity. He explained that growth in earnings is positively correlated to the amount of earnings reinvested and then multiplied by the return earned on those reinvested funds, measured using return on equity. Dr. Cleary noted that it is difficult to find representative Canadian regulated public-traded utilities. He applies averages and medians of historical data to arrive at an estimate of sustainable growth rates. Using an estimated sustainable growth rate of 1.64% produced an implied return of 7.01%.

[497] Due to a negative average return on equity in his dataset, and what he considered to be abnormally high payout ratios in 2024, Dr. Cleary did not apply his H-Model to his Canadian utilities sample. However, he compared the results to his results for the overall market. Adjusting for cost of debt and flotation costs, Dr. Cleary calculated a required return of 7.86% using this approach.

3.7.3.3 Risk Premium Model

[498] The risk premium model can be based on differences in the return between bonds and equity or the expected bond-equity return spread. The risk premium model accounts for equity holding more risk than debt because the equity investors bear the residual risk associated with ownership and therefore require a higher return than a bondholder. The riskier the company, the greater the difference between these returns. The standard equation for the risk premium calculates the return on equity as the sum of the yield on long-term bonds and the equity risk premium.

[499] Both Concentric and Dr. Cleary used the risk premium model, but they did so in entirely different ways. A summary of the formula components used by Concentric and Dr. Cleary is set out in the table below:

	Risk Premium	
	Concentric	**Cleary**
A-rated Utility Bond Yield (Nova Scotia Power)		**4.94% [Bloomberg]**
Government Bond Yield (Canada)	**3.82% (average)** *[Calculated from Bloomberg and Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]*	
Risk Premium (Canada)	**5.71% (average)** *[Calculated from Bloomberg and Average long-term Consensus Forecast of 10-year government bond yields plus the average spread between 10- and 30-year bond]*	**2.5%** [Usual range of 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies]
Government Bond Yield (U.S.)	**4.68% (average)** *[Bloomberg and Blue Chip Financial]*	
Risk Premium (U.S.)	**5.96% (average)** *[Calculated from Regulatory Research Associates, Bloomberg and Blue Chip*	
Financial Flexibility		**0.50%**
ROE	9.52% (Canada) 10.63% (U.S.) **10.04% (mean)**	**7.94%**

[500] Concentric stated that “the equity risk premium is not directly observable…”. In its place, Concentric employs a regression analysis to assess the relationship between the authorized equity returns for utilities against 30-year government bonds. Data for over 700 U.S. and 60 Canadian electric utilities dating back as far as the early 1990s was input into Concentric’s analysis. Concentric also modeled variations of average long-term bond rates and then averaged the results. These results were added to the risk premium derived from the regression analysis to arrive at an overall risk premium return on equity, one for Canada, one for the U.S. and an average of the two.

[501] Dr. Cleary explained that his model examines the relationship between bond and stock markets using readily observable market-determined bond yields. He used current market long-term debt costs for A-rated utility bonds in Canada and the corresponding Bloomberg data for each utility. He noted that the yield on NS Power’s bonds maturing in 2042 was 4.94%, higher than the other utilities he analysed. He considered that this higher yield was a reflection of the other utilities holding higher credit ratings and longer maturity terms.

[502] To determine the risk premium side of the equation, Dr. Cleary contemplated that the typical range of risk premiums for utilities is between 2% and 5%. He considered that NS Power is a low risk regulated Canadian utility and suggested a low-risk premium between 2% and 3% is appropriate. He settled on 2.5%. Dr. Cleary then summed NS Power’s mid-point bond yield with this risk premium and applied an adjustment for flotation costs to arrive at 7.94%.

3.7.4 Party Submissions

[503] The Affordable Energy Coalition’s (AEC) opening statement submitted that the Board must ensure rates are sufficient to cover NS Power’s cost-of-service, while

preventing the recovery of excess spending and profits. The AEC characterized NS Power as a low risk regulated monopoly and argued that the utility should not face difficulty securing capital for its low-carbon investments. It also emphasized that many low-income Nova Scotians already experience significant cost-of-living pressures, making further rate increases untenable.

[504] The AEC's opening statement noted that Emera's annualized 10-year total shareholder returns ranged between 8.8% and 11.5% in 2022 and 2023 and questioned the justification for maintaining NS Power's 9% return on equity considering this profitability. The AEC submitted profit parameters should be adjusted to limit excess earnings and recommended reducing the return on equity to 7.6%, consistent with Dr. Cleary's evidence.

[505] In its closing submissions, NS Power argued that a fair return standard would warrant a higher return on equity and a thicker equity ratio based on Concentric's evidence, but it was maintaining its current return on equity and capital structure to balance affordability for customers:

> In sum, NS Power is aware of the need to balance affordability for customers and the financial health of the utility and, as a component of the Settlement Agreement, is therefore seeking to maintain its current ROE of 9.0 percent and an equity ratio of 40 percent. The Company's requested 9.0 percent ROE is below the market-based cost of equity provided by Concentric. For its North American proxy group, most like NS Power, the range of results with market data as of January 31, 2025 was 9.29 to 10.32 percent, and updated in response to the Board's undertaking to 9.02 to 10.43 percent with market data as of December 31, 2025. Even the lowest estimate using the multi-stage DCF model exceeds the Company's requested ROE. [Footnotes omitted]
>
> [NS Power Closing Submissions, p. 45]

[506] In addressing Dr. Cleary's evidence, NS Power contrasted the approaches taken by Concentric and Dr. Cleary. It said Concentric used proxy companies selected to match NS Power's business and operational risks, but Dr. Cleary relied on a very limited

group of companies that did not represent NS Power's business risk profile as a vertically integrated utility. It noted that in discussing the relative risk of Canadian and U.S. utilities in his evidence, Dr. Cleary focusses on utilities in Ontario and Alberta without considering how NS Power's risk profile may be different.

[507] NS Power submitted that Dr. Cleary's evidence was also undermined through his use of inputs based on his own personal judgement rather than current market data. It said other inputs and assumptions were not reasonable given the context of current and prospective economic and capital market conditions.

[508] In its closing submissions, the NDP Caucus encouraged the Board to "review the evidence presented by Dr. Cleary, who suggests Nova Scotia Power's rate of return should be set lower than the nine per cent".

[509] The Department of Energy filed closing submissions stating:

> 26. …A higher ROE is clearly in NS Power's interests, but it is not in the public's interest that ratepayers are asked to pay more. This is particularly the case where ratepayers contribute to NS Power's returns despite poor reliability performance, including continually failed SAIDI and SAIFI standards, most notably in rural Nova Scotia. Much of Nova Scotia is rural, and power outages can deprive ratepayers not only of light and heat but also access to well water. NS Power should not be permitted to earn more by delivering less.
>
> 27. NS Power did not offer any rebuttal to Dr. Cleary's evidence. Dr. Cleary offers the best evidence in this proceeding with respect to appropriate ROE, noting that NS Power has, since 2012, earned its allowed ROE on average, exceeding the allowed ROE in 8 of 12 canvassed years.
>
> [Department of Energy Closing Submissions, p. 5]

[510] In its reply submissions, NS Power addressed the Department of Energy's comments as follows:

> The DOE has offered no justification for its request that NS Power's return on equity be set at 7.6 percent, other than the mere presence of Dr. Cleary's evidence on the record. While the DOE states that NS Power did not offer any rebuttal to Dr. Cleary's evidence, again this is not true, as Dr. Cleary's evidence was rebutted by Mr. Coyne in his oral testimony and also within NS Power's Closing Submissions. What should also be seen as rebuttal of Dr. Cleary's evidence is the agreement and support from customer representatives for the use of 9 percent as the return on equity. Notably, the DOE has offered no evidence or submissions to rebut the evidence of Mr. Coyne. In fact, the DOE's submissions do not reference Mr. Coyne's evidence at all; however, the DOE submissions do provide support

> for Mr. Coyne's evidence as they only serve to further demonstrate NS Power's risk profile is higher than its peers. NS Power continues to rely on the evidence on the record in this proceeding and on its closing submissions to justify the requested, and customer representative-supported, 9 percent return on equity.
>
> [NS Power Reply Submissions, pp. 9-10]

3.7.5 Findings

[511] It bears repeating that for at least a century, the Supreme Court of Canada has recognized that investors in regulated utilities are entitled to a fair return that is comparable to the return they would see from other investments of similar attractiveness, stability and certainty. Without this, investment may be discouraged and the utility may not be able to expand or maintain its operations, harming both its shareholders and its customers.

[512] Factors that may be appropriately taken into account in setting a fair return are comparable returns on similar investments, the level of return needed to attract capital and the financial integrity of the utility. Factors that other cases have determined are not appropriate to consider include the impact of a fair return on rates or as a tool for balancing other interests between the utility and its customers, such as affordability or reliability. That is not to say these factors are irrelevant, just that they are not properly taken into account in setting the allowed return. There are other regulatory tools that can be used to lessen near term rate impacts and affordability issues, but they generally come at a higher long-term cost and may shift costs to other or future customers who did not receive the benefit of the service to which the costs relate.

[513] The NSUARB considered this issue directly in its decision about NS Power's request to set new rates in 2005. In that case, the start of the hearing was delayed due to an early winter storm in November 2004 that left thousands of Nova Scotians without power – some for many days. In the wake of the storm, Premier John

Hamm asked the NSUARB to conduct an independent review of the utility's state of preparedness before the storm. Many questioned why a rate increase should be considered in the circumstances. The Board said:

> [14] Just prior to November 15, 2004, the first scheduled day of the public hearing, NSPI requested that the hearing commencement be delayed until November 16, 2004. This request, which was agreed to by the Board, was as a result of significant power outages in various communities in the Province following a storm on November 13 and 14, 2004.
>
> [15] The November outages are the subject of a separate review by this Board. On November 16, 2004, the Board received the following request from Premier John Hamm:
>
> > The Government of Nova Scotia believes that the public interest would be served if the Utility & Review Board conducted an independent review. I therefore request that the Utility & Review Board, under the powers of the Public Utilities Act, begin a public review of the Company's state of preparedness for, and response to, last weekend's storm.
> >
> > This review should provide valuable insights into improvements which can be made to the overall restoration program in preparation for future outages.
>
> [16] As part of the outage review, the Board has received a number of comments from members of the public questioning, among other things, why NSPI's request for a rate increase should be considered when the service provided by NSPI is, in the view of these customers, inadequate and unsatisfactory.
>
> [17] While the Board recognizes the logic of this reaction, it is important to understand why this form of sanction cannot reasonably be applied to a regulated utility. NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the Utility is permitted, under the Act, to recover the reasonable and prudent costs of providing this service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.
>
> [18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.
>
> [19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly. The Board cannot, however, make rate decisions based solely on reliability issues or current public opinion of the Utility. There are appropriate sanctions a regulator can impose should a Utility be found to have an inadequate or unreliable system. In many cases, it is likely such sanctions would involve higher expenditures, rather than reductions in costs.

> However, the practical reality in a regulated utility environment is that sanctions for service-related issues generally do not include a moratorium on rate increases.
>
> [2005 NSUARB 27]

3.7.5.1 Return on Equity

[514] A utility's return on equity must be consistent with the fair return standard. There is no single test for determining an appropriate return on equity. Both experts in this proceeding used a variety of models and averaged the results of these models to produce a specific recommendation for an appropriate rate of return. However, the Board understands that each expert informed their opinion from the range of results from these approaches.

[515] In his evidence, Dr. Cleary said:

> I have weighted all three of my [required return on equity] estimates equally because all three methods are used in practice and provide different perspectives on [required return on equity]. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. …
>
> CAPM is also more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.
>
> I also give equal weighting to the BYPRP [Bond Yield Plus Risk Premium] approach which is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for market-determined borrowing rates and risk. In fact, the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned earlier. Thus, the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such it is intuitively sound.
>
> [Exhibit N-32, pp. 74-75]

[516] Dr. Cleary gives equal weighting to the three approaches he used as his "best estimate" for allowed Canadian equity returns. At the hearing, he said that, properly implemented, all of these approaches "can provide useful guidance".

[517] In its evidence, Concentric noted:

> No financial model can exactly pinpoint the correct [return on equity]; rather, each test brings its own perspective and set of inputs that inform the estimate of the [return on equity].

> Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling." Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor-required [return on equity], analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.
>
> Other Canadian utility regulators, including the BCUC, the OEB, and the AUC, have acknowledged the need to use multiple methodologies in determining a fair return on equity. [Footnotes omitted]
>
> [Exhibit N-8, Appendix 10A, p. 33]

[518] In addition to the inherent weakness across analytical models, it is apparent from the evidence in this proceeding that an expert's selection of model inputs and their assumptions can also vary – in some cases, quite significantly. In some instances, the Board might have cause to question or give less weight to an input or assumption. In others, differences in approaches might be better described as points over which reasonable experts can disagree. The Board can use all this information to inform its conclusions about an appropriate return on equity.

[519] In the present case, the results of Dr. Cleary's models produced a range of equity returns from 6.8% to 7.9%, with an average recommended return on equity of 7.6%. Concentric's models, based on its Undertaking U-14, produced a range of results from 9.0% to 10.0%, with an average recommended return on equity of 9.4%. The Board finds that neither of the experts' recommended averages meet the fair return standard. For reasons set out below, Dr. Cleary's recommendation is too low and Concentric's is too high. An appropriate return on equity for ratemaking purposes lies somewhere between these estimates.

[520] Before considering the strengths and weaknesses of the models, inputs and assumptions used by each expert, the inclusion of U.S. data in the assessments must be considered. This was a fundamental point of difference in the overall approaches taken

by each expert in this proceeding and fundamentally affects the results produced in their models.

[521] While the Board accepts Concentric's view that the economies of Canada and the U.S are highly integrated, the Board does not agree that this makes it appropriate to treat Canadian and U.S. data as fully interchangeable in a cost of capital analysis for a Canadian regulated utility. There are political and regulatory differences between the two countries. Dr. Cleary indicates there are corporate structural and operational differences between Canadian and U.S. regulated utilities. He submits Canadian utilities operate under more supportive regulatory environments. As noted, in his recent testimony before the Board in the NSPML 2026 cost assessment matter, he expressed the view that institutional and fixed income investors in Canada (and elsewhere) show a home-country bias for investment.

[522] The Board also observes some differences in the data filed in this proceeding. While suggesting some correlation, Concentric's response to Undertaking U-14 identified lower overall average total returns in Canada on the S&P/TSX compared to the S&P 500 in the U.S. over 25, 10 and 5 years (with a wider gap in the past 10 years); somewhat lower average real GDP growth in Canada relative to the U.S. over the past 25, 10 and 5 years; slightly lower inflation in Canada averaged over the same periods; and slightly lower 10-year government bond yields. In terms of the return on equity results, Concentric's Canadian proxy group produced the lowest results in all its models and the Canadian companies within its North American proxy group produced lower return on equity results than the U.S. companies in all its models.

[523] On the other hand, the Board does not agree with Dr. Cleary that U.S. regulated utility data should be entirely excluded. The pool of regulated utilities in Canada is far more limited than in the U.S., and in respect of fully integrated investor-owned utilities like NS Power, quite so. Comparing NS Power to regulated utilities in Canada may, in many respects, be more apt than to regulated utilities in the U.S. However, one must also be cautious about comparing NS Power to other Canadian utilities that do not share the same degree of risk, particularly risk associated with generation assets and the circumstances the utilities face in decarbonizing and the energy transition. The Board views Concentric's selection of its North American proxy group to be an attempt to address some of these other risks.

[524] Overall, the Board finds that, while it must be mindful that Concentric's use of U.S. data is likely inflating results in the analysis, Dr. Cleary's omission of U.S. utilities is likely producing results that are lower because the utility data he uses is largely comprised of a number of Canadian utilities that do not share NS Power's higher electricity generation or energy transition risks. The Board must consider and weigh the results from both experts accordingly.

[525] The Board notes the Ontario Energy Board reached a similar conclusion in its recent generic cost of capital proceeding:

> Substantial differences remain between Canadian, and U.S.-based utilities principally associated with risk, regulatory oversight and the engagement of U.S. regulated utilities in non-regulated business operations. As well, holding company structures and business holdings, operating in the U.S. and not in Canada, decrease comparability of regulatory results. The OEB concludes that the "home bias" of the Canadian investor to invest in Canadian utilities is a factor in giving less weight to U.S. comparators. These differences cannot be ignored in the OEB's efforts to set parameters to meet the FRS.
>
> …
>
> The integration of U.S. and Canadian utility markets and the potential lure of higher returns for investors is a factor to be considered in arriving at a final conclusion concerning the requisite return on equity that must be provided to meet the FRS. However, the use of U.S.

> regulated utility data as equivalent to Canadian regulated utility data in any computation is questionable.
>
> [EB-2024-0063, pp. 36-37]

[526] The Alberta Utilities Commission had similar comments in its decision in its most recent generic cost of capital proceeding:

> 103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada. Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets. Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.
>
> 104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the return on equity required by investors in the Alberta utilities. [Footnotes omitted]
>
> [Decision 27084-D02-2023, p. 22]

[527] In the paragraphs that follow, the Board outlines its assessment of the models, inputs and assumptions advanced by the experts in this proceeding, beginning with the CAPM.

[528] Notwithstanding the statistical analysis Dr. Cleary provided in Appendix A to his evidence, it has not been sufficiently demonstrated in this proceeding that there is a systematic upward bias of Consensus Economics' forecasts of government bond yields used by Concentric to determine its risk-free rates in its CAPM. It would be surprising if any forecast of this nature matched actual results. And while Dr. Cleary's data showed several times when forecasts exceeded actuals, there were more recent periods when the reverse was true. However, the use of 10-year bond yields adjusted by historical

spreads to derive a 30-year bond yield introduces the need for other assumptions and procedures in the analysis that cause the Board to have less confidence in Concentric's results.

[529] The Board is also not satisfied that Dr. Cleary's use of 30-year government bond yields on a single day is likely to provide any better results. Aside from any issue about whether it is more appropriate to use a historical trend or a forecast, a single data point poses a greater risk of introducing an anomalous event impacting the metric on that day into the analysis.

[530] Because these witnesses tend to give similar evidence in regulatory proceedings in other jurisdictions, the Alberta Utilities Commission had similar comments on these issues relating to the evidence provided by the witnesses in its recent cost of capital proceeding:

> 110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.
>
> 111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as "the Big Six" banks. In the Commission's view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.
>
> 112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast, using the actual 30-year GoC bond yield to inform an estimate of the future 30-

> year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point. However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.
>
> 113. The Commission will use the bank forecasts published in February 2023 provided by D. D'Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast. [Footnotes omitted]
>
> [Decision 27084-D02-2023, p. 24]

[531] Thus, while the risk-free rate estimates advanced by Concentric and Dr. Cleary are close (at least for the Canadian rate used with Concentric's Canadian utilities in its North American proxy group which is 3.87% compared to Dr. Cleary's 3.66%), the Board finds they are both subject to inherent weaknesses.

[532] Aside from the use of U.S. data, Dr. Cleary's other major complaint about Concentric's estimate for its market risk premium was about its use of "income only returns" rather than total returns which he said was standard for finance professionals. The Board considers there is merit in this criticism. As a result, it is likely that Concentric's market risk premium is also higher than it should be because of this issue.

[533] However, Dr. Cleary's market risk premium is not without its own vulnerability. While the Board has no specific reason to question Dr. Cleary's professional judgement and experience that market risk premiums generally fall within a range of 4%-6%, the assessment is more subjective. This is especially true about what part of the range should be used in any given case.

[534] Once again, Dr. Cleary's estimate of 5.5% is somewhat comparable to Concentric's 5.75% for its market risk premium. But because Concentric uses a blended market risk premium, its much higher U.S. estimate causes the premium it uses in its formula to be about 100 basis points higher than Dr. Cleary's market risk premium.

[535] The experts disagreed on the use of adjusted betas. To different extents, both suggested there was statistical or historical information supporting their respective positions. Given the evidence in this proceeding, a choice between these two approaches would be somewhat arbitrary. However, in the context of a return on equity analysis where the general approach is to analyse the issue using a number of different methods to better inform an overall result, using both adjusted and unadjusted betas could provide evidence of a range of results that may be reasonable. This is the approach taken by the Alberta Utilities Commission:

> 130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk. Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.
>
> …
>
> 132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen and D. D'Ascendis). The high end of Dr. Villadsen's beta estimates were well above this range. [Footnotes omitted]
>
> [Decision 27084-D02-2023, p. 29]

[536] While the only evidence about ranges in this proceeding was the 0.3 to 0.6 range suggested by Dr. Cleary, the Board notes that Concentric's average beta in its CAPM was just a bit higher than that range, but within the range suggested in the Alberta Utility Commission decision. And as with his market risk premium assessment, Dr. Cleary's approach to estimating the beta within a generally accepted range is subjective, compared to the approach taken by Concentric.

[537] Overall, the Board's findings relating to the use of the CAPM model only reinforce the general observation that the results produced in Concentric's model are too high, and the results produced in Dr. Cleary's model are too low.

[538] The selection of growth rates was the most significant area of controversy about the application of the DCF approach by the experts. Concentric relies on analysts' earnings growth forecasts, which, Dr. Cleary said, are typically regarded as overly optimistic. While Concentric disagrees with this, it says any optimism bias was mitigated by using earnings growth forecasts from several sources.

[539] Dr. Cleary also noted that the overall growth rate implied by taking into account all stages of Concentric's multi-stage DCF exceeds nominal GDP growth. Dr. Cleary suggested this is "an ambitious target for low-risk utilities". He suggested such a rate assumes these utilities will outperform the productivity of Canada and the U.S. in perpetuity. Dr. Cleary considered this to be an unrealistic assumption for a utility. The Board finds there is merit in this criticism.

[540] On the other hand, Dr. Cleary's "sustainable growth rate" of 1.64% seems unreasonably low for a growth rate under a model that is presumed to continue to infinity. Dr. Cleary notes in his evidence around the application of his market DCF estimate, that "we are trying to estimate a 'nominal' required rate of return, so we should use nominal GDP growth". If the sustainable growth rate he uses in his Canadian utility DCF estimate is also intended to be nominal to derive a nominal required rate of return, and Dr. Cleary's assumed inflation rate is 2%, it seems especially low for a long-term assumption.

[541] Both of these points are also featured in the Alberta Utilities Commission's recent cost of capital decision:

> 153. In the 2018 GCOC decision, with reference to Dr. Cleary's evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable. Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.

> 154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary's sustainable growth rate produces results that understate dividend growth. [Footnotes omitted]
>
> [Decision 27084-D02-2023, p. 34.]

[542] As with the Board's conclusion about the CAPM, the growth rates used by the experts in their DCF models reinforce the Board's general observation that the results produced in Concentric's model are too high, and the results produced in Dr. Cleary's model are too low.

[543] The regression analysis in Concentric's risk premium model uses long-term government bond yields and equity risk premiums. The equity risk premiums in the regression analysis are obtained from the difference between regulator allowed ROEs and 30-year government bond yields. The bond yields in the Canadian version of this model use the same approach as the calculation of the risk-free rate in its CAPM model and are therefore subject to the same weaknesses.

[544] The Board is concerned about the nature of this approach. Using authorized equity returns from other jurisdictions reflects regulatory decisions shaped by legislation, policies and economic conditions that may be unique to those jurisdictions. They are not directly derived from market-based data and are only indirectly derived to the extent that the regulator approving the return on equity considered and accounted for market data.

[545] In his evidence, Dr. Cleary submitted that authorized ROEs have not declined adequately in response to reductions in government and A-rated utility bond yields over the last two decades. Based on the evidence in this proceeding, it is not clearly demonstrated to the Board that this is correct; however, to the extent that there was any

"stickiness" in allowed ROEs, following the risk premium approach used by Concentric would likely contribute to that.

[546] Dr. Cleary's risk premium approach uses utility bond yields and adds a risk premium. As with elements of his other models, the risk premium exhibits a high degree of subjectivity through the selection of a point, generally in the range of 2 to 5%, based on the deemed riskiness of the company. The evidence about this in this proceeding lacked empirical rigour.

[547] The Alberta Utilities Commission also had concerns about these approaches and refused to rely on them in its recent cost of capital decision:

> 165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair return on equity estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D'Ascendis relied on the utility bond risk yield premium model; and (iii) D. D'Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.
>
> 166. The government bond risk premium approach estimates the return on equity as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions, the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.
>
> 167. Under the utility bond risk premium approach, a required return on equity is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.
>
> 168. Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment.

[548] In this case, the Board finds that the risk premium models are of quite limited value, even relative to the other models with their weaknesses, and will weigh them accordingly.

[549] Having reviewed the return on equity models in detail, the Board finds that Concentric's recommendation is too high and Dr. Cleary's is too low. The evidence in this matter does not support adopting either, but it does firmly support setting a return on equity within that range. However, evidence supporting the selection of a specific point between these two recommendations is less firm.

[550] The parties to the settlement agreement agreed to maintain NS Power's current return on equity of 9% for ratemaking purposes, with an earnings band of 8.75% to 9.25%. Under this proposal, the Board notes that any earnings above 9.25% would be returned to customers under s. 64C of the *Public Utilities Act*. However, NS Power is not entitled to any additional recovery in the event earnings are below 8.75%.

[551] The Board finds it is appropriate to accept this proposal under the settlement agreement for several reasons. As discussed, the evidence does not support adopting the recommended rates of either Concentric or Dr. Cleary, and the proposal under the settlement agreement falls within these rates which the Board considers too high and too low. In other aspects of this decision, where the Board has found that the evidence supported a departure from the settlement agreement, and the Board has determined it is in the public interest to do so, it has departed from what was proposed. But as noted, the evidence does not otherwise point to a better placement for the return on equity within the high and low points set by the expert evidence.

[552] The parties to the settlement agreement are sophisticated parties who represent the interests of all NS Power's rate classes. These parties participated in a pre-application review of NS Power's proposed rate increases that involved focussed discussions with NS Power to resolve matters of disagreement arising from NS Power's

proposed application. These parties are typically the most active in Board proceedings involving NS Power and frequently present the Board with expert evidence and submissions on matters of concern. Given this, the Board has some comfort that the public interest has been addressed.

[553] Notwithstanding his views, Dr. Cleary recognized the settlement agreement was a factor for the Board to consider in setting NS Power's return on equity:

> The settlement agreement that was reached by NS Power and customer representatives recommends [*sic*] a continuation of NS Power's currently allowed return on equity of 9% and 40% equity ratio. While remaining confident in my market-based return on equity and equity ratio recommendations, I acknowledge that reaching a settlement agreement does involve trade-offs that the Board must take into consideration.
>
> [Exhibit N-32, p. 6]

[554] While, as noted above, the Board finds it inappropriate to calculate a required return on equity using authorized equity returns, the Board finds it acceptable to reference returns awarded elsewhere in Canada in the context of assessing the overall reasonableness of the settlement agreement. Considering Figure 30 from Concentric's evidence (reproduced earlier in this decision), it is apparent that maintaining NS Power's return on equity would not make it an outlier in Canada, with most of the other Canadian electric utilities falling within a narrow range. The only utility with an appreciably lower return on equity was Newfoundland Power (8.6%), a Crown corporation with a higher equity ratio at 45%.

[555] In the hearing for NSP Maritime Link's 2026 annual assessment (Matter M12394), Dr. Cleary was asked to respond to a statement made by Concentric that a 7.6% return on equity would be the lowest authorized return on equity of an investor-owned regulated utility in North America. Dr. Cleary responded, "[t]o the best of my knowledge, 7.6% would be the lowest recommended return on equity in Canada".

[556] Setting a rate of return that low could have far reaching consequences. This was the subject of comment by the Ontario Energy Board, where Dr. Cleary recently recommended an even lower return on equity of 7.05% for utilities in that province:

> There is evidentiary support for a significant reduction to the current return on equity advanced by Dr. Cleary. Both Dr. Cleary and LEI are instructive in providing reassurance that the regulator has discharged its responsibility to the utilities it regulates in meeting the FRS for their continued operation. The remaining question is whether the current return on equity results in rates that are greater than required to meet that standard thereby generating economic rent from utility customers.
>
> Dr. Cleary's evidence endeavors to show a result that could meet that question in the affirmative. The effort produces a result that differs markedly from the other expert evidence by recommending a considerably lower estimate, with much of that difference attributable to his reluctance to accept the comparability of Canadian utilities with U.S. counterparts. His model thus engages a smaller number of comparators. As noted earlier, the OEB also has concerns about the ability to find true comparators from the U.S., which limits the number of comparators that might be definitively used.
>
> However, a significant recommended change from the results of the current formula that has been meeting the FRS for utilities must be done with caution. The submissions of the EDA and the OEA set out potential concerns regarding an return on equity reduction such as recommended in Dr. Cleary's proposal. The OEA pointed to the risk of negative credit rating impacts, which could increase the cost of debt financing for Ontario utilities and impose additional costs on ratepayers. The OEA also emphasized that setting an return on equity at an insufficient level would constrain the growth prospects of Ontario utilities by reducing projected earnings per share growth, potentially forcing utilities to offer higher dividend payouts to attract equity investment. These outcomes would create financial pressures inconsistent with the requirement that utilities earn a fair return. Dr. Cleary himself acknowledged that a steep drop in return on equity could create instability for regulated utilities from a credit rating standpoint. [Footnotes omitted]
>
> [OEB EB-2024-0063, pp. 38-39.]

[557] As noted, NS Power's current credit rating from S&P already places it in the bottom 10% of utilities in North America. The evidence in this proceeding, especially the evidence presented by Morrison Park that was discussed elsewhere in this decision, already raises concern about NS Power's ability to maintain even its current low rating. A failure to do so could cause its cost of debt (which comprises 60% of NS Power's capital structure) to increase and result in other financial consequences to the detriment of NS Power's customers. Morrison Park said, should NS Power's rate requests be rejected and its securitization plan not bear fruit, then it would be a certainty that the 10% FFO:Debt

target would be missed in both 2026 and 2027 and put NS Power at risk of further credit rating downgrades. Setting a return on equity at 7.6% would materially reduce NS Power's funds from operations and make its 10% FFO:Debt target more difficult to achieve.

[558] The Board finds it would not be in the public interest to approve a return on equity that does not meet the fair return standard and deviates materially from the range of equity returns authorized for similar utilities across Canada. This reluctance is heightened by the array of investment disincentives identified in the evidence of Morrison Park, which collectively underscore the importance of maintaining NS Power's ability to attract capital and preventing any further deterioration of the utility's credit rating that would likely result in increased costs for customers.

[559] To ensure NS Power can undertake required significant capital investments, the Board acknowledges that investors will assess the relative attractiveness of investing in NS Power compared with other Canadian utilities. The Board finds that maintaining a return on equity of 9.0% for rate-setting purposes, with an earnings band of 8.75% to 9.25%, is in the long-term interests of customers.

3.7.5.2 Capital Structure

[560] NS Power proposed to maintain its capital structure of 40% equity and 60% debt. This request was supported by its expert witness Concentric (which considered 45% would be appropriate), Board Counsel consultant, Dr. Cleary, and the signatories to the settlement agreement. No party opposed NS Power's request. The Board finds it is appropriate to accept the proposal in the settlement agreement to maintain NS Power's capital structure.

3.8 Cost of Service Study

[561] Under the *PUA*, a utility is afforded the opportunity to recover its "reasonable and prudent" costs of providing service and a "just and reasonable" return on its rate base. The total amount of these costs and the return on rate base is generally referred to as the utility's "revenue requirement".

[562] Once the revenue requirement is determined, customer rates are set to produce revenue equal to this amount. Under s. 67(1) of the *PUA*, rates charged to customers "under substantially similar circumstances and conditions in respect of service of the same description" must be charged equally to all customers.

[563] Grouping customers into classes that receive service under substantially similar circumstances and conditions requires judgement. Many factors influence this determination. In L.R. Nash, *Public Utility Rate Structures* (New York and London: McGraw-Hill Book Company Inc., 1933), p. 273, the author states:

> Discrimination is commonly understood to mean a difference in rates or service conditions relating thereto for service of substantially the same characteristics, taking into account volume, load factor, load density, time of use, character of use, and any other significant factors. Because of the many factors involved in discrimination, its precise definition is necessarily left to the judgement of the regulatory commissions in each case.

[564] In *Dalhousie Legal Aid Service v Nova Scotia Power Inc.,* 2006 NSCA 74, the Court of Appeal noted that differences in rates charged to customers may only be justified based on how they receive service from the utility. Other differences, such as a customer's ability to pay, cannot be used to establish rates in Nova Scotia (based on the legislation as it is currently written):

> [23] DLA's factum said that low income customers do not have "substantially similar circumstances" to higher income customers. So, different rates would not be barred by s. 67(1). At the appeal hearing DLA's counsel retreated somewhat from this submission.
>
> [24] With respect, the factum's submission misinterprets s. 67(1). The provision refers to "substantially similar circumstances and conditions ***in respect of service of the same description***." To justify a rate difference, the relevant dissimilarity is not in customers'

> incomes. It is in the service from NSP. The Board accepted, and there is no basis to question, that NSP provides substantially similar electrical service whatever the domestic customer's income.
>
> [25] Section 67(1) is mandatory. The rates and charges "shall always . . . be charged equally" to persons of similar circumstances and conditions in respect of service. The statute does not endow the Board with discretion to consider the social justice of reduced rates for low income customers. It is not for the Board or this court to read into s. 67(1) the words:
>
> > . . . similar circumstances and conditions in respect of ***the income level of customers and*** service of the same description,
>
> It is for the Legislature to decide whether to expand the Board's purview with the italicized words. [Emphasis in original]

[565] The same rationale applies to the request for the creation of a Mi'kmaq Rate Class, as set out in the Letter of Comment sent to the Board on behalf of the Kwilmu'kw Maw-klusuaqn Negotiation Office (KMKNO) and the Assembly of Nova Scotia Mi'kmaw Chiefs [Exhibit N-1, pp. 24-26]. The socio-economic, housing, geographic, and demographic factors discussed in the Letter of Comment do not relate to differences in the way electricity is provided to Mi'kmaq households, businesses and community buildings, which is similar to how it is provided to households, businesses and community buildings outside of Mi'kmaq communities. Rather, those differences relate to the unique circumstances and conditions of the Mi'kmaq communities themselves. The statute does not allow the Board to set a separate rate based on customer-related differences, only service-related differences.

[566] Although rates must be charged equally to customers "under substantially similar circumstances and conditions in respect of service of the same description", responsibility for the revenue requirement is not divided equally among NS Power's customer classes. This is because different classes of customers do not use the electrical system in the same way. They take service under different circumstances and conditions and impose different costs on the system. For example, to serve domestic customers, the

utility must have an extensive distribution system. Large industrial customers may not require this infrastructure and, therefore, the cost to serve these two classes of customers may be quite different.

[567] The utility's revenue requirement must be fairly divided among its customer classes based on how each class contributes to system costs. A fair allocation of costs ensures that all customer classes pay for the costs of the service they receive and their rates do not subsidize the rates of other customer classes. This allocation of costs is performed using a cost-of-service study, which is prepared by the utility and identifies the costs attributable to each customer class.

[568] Despite involving a considerable amount of system and customer data, the distribution of costs under a cost-of-service study is not an exact science. As NS Power's consultant, Andrew Blair, Elenchus Research Associates Inc., noted in response to questions at the hearing, a cost-of-service study involves a lot of judgement and, in some respects, may be considered more of an art than a science:

> **Q.** And, Mr. Blair, do you agree that the cost of service allocation it's not a pure science?
>
> **A.** (Blair) That's right. It's often said it's more of an art than a science.
>
> **Q.** Yeah, there's a lot of subjectivity, generalization, averaging, simplification that's involved in the processes?
>
> **A.** (Blair) Yes, there's a lot of judgment that goes into what the methodology should be and then it sort of turns into a science from there. But, yeah, at the first stage there's a lot of judgment.
>
> **Q.** And would you agree that as a result many regulators often recognize sort of a range of reasonableness as the outcome of cost allocations, so in this particular jurisdiction so the 95 percent to 105 as opposed to trying to precisely target 100 percent allocation under a particular method to each rate class?
>
> **A.** (Blair) Yes. I believe a range of reasonableness is used in every jurisdiction in Canada for electricity.
>
> **Q.** And in this particular model the end result is showing for the residential class a 97.18 percent under a revenue-to-cost ratio. That's -- I'm interpreting the table correctly?

A. (Blair) That's correct.

Q. Yeah. And so consistent with what you just said, we wouldn't necessarily think of that as being subsidized by other rate classes. It's within that range of reasonableness and, you know, within the range of that's appropriate costs that are allocated to that particular class?

A. (Blair) Yes, that's right.

[Transcript, January 7, 2026, pp. 163-164]

[569] In NS Power's case, costs are directly allocated to a specific rate class when this is possible because they are clearly and directly connected to that class. An example of this is the capital and maintenance related costs of streetlight fixtures, which are assigned directly to streetlight classes based on information acquired from NS Power's financial books and records or through additional analysis or studies. Shared costs that are not directly assigned are analyzed in the cost-of-service study.

[570] The first step in the process is to identify costs based on the high-level function they serve in providing overall service to customers. In NS Power's case, costs are functionalized into groups based on whether they relate to production, transmission, distribution or retail functions.

[571] After this step, the functionalized costs are classified based on their relationship with different services. Generally speaking, demand costs relate to the utility's capacity to provide service to customers, energy costs relate to the energy provided to customers, and customer costs are costs that are driven by the number of customers served.

[572] Next, various factors are developed to allocate the classified costs to NS Power's customer classes. These allocation factors may consider certain characteristics of the customer class such as the number of customers, the demand that the customer class imposes on the system, and the amount of energy used to serve the customer class.

[573] It has been more than 10 years since NS Power's cost-of-service methodology has been comprehensively reviewed in a proceeding before the regulator. The last proceeding focused on cost-of-service methodologies that was before the NSUARB occurred in 2014 (2014 NSUARB 53).

[574] Since then, there have been concerns that changes in the electricity sector warranted a review and potential updating of NS Power's cost-of-service methodologies. These changes include increasingly stringent requirements to decarbonize, the development of the Maritime Link and access to market energy, increased regional wind and solar penetration, grid scale battery storage, increased reliance on purchased power agreements and increased investment intended to support electrification and distributed energy resources. As a result, in NS Power's last general rate application, the utility and several intervenors agreed that a cost-of-service study would be completed through an engagement process before NS Power's next general rate application (or by December 31, 2025, whichever was sooner).

[575] In its decision, the NSUARB agreed that NS Power's cost-of-service study should be updated to reflect developments impacting NS Power's system since the last review of its cost-of-service study in 2013/2014. The NSUARB directed that all cost allocation methodologies should be reviewed for their continued relevance and application.

[576] In the present application, NS Power provided information about the engagement process it followed in developing the cost-of-service proposals it has put forward for approval. NS Power's summary of this process in its application stated:

> Throughout 2024, technical conferences were held to provide in-depth educational sessions on the current COS treatment at NS Power and identify the primary issues to be resolved as part of the formal regulatory process, areas requiring additional examination,

> and areas of consensus and disagreement among parties. The goal of these sessions was for the Company to determine its view of the appropriate path forward, ideally with the development of a consensus agreement. This process culminated in two full-day Resolution Sessions. These sessions were held in person with stakeholders and expert consultants present, and NS Power retained Bruce Outhouse (KC) to mediate these sessions.
>
> The process proved to be beneficial and has served to streamline COS discussions in the context of the GRA. NS Power received positive feedback from stakeholders concerning the opportunity for productive discussion and the breadth of information provided in this process. An extensive exchange of information took place through presentations, modelling, and data request (DR) cycles across the year. 67 models and iterations of models were prepared and are attached to this COSS as **Appendix 12A(1)**. In addition to that, stakeholders asked 152 DRs, these DRs and NS Power's responses to those DRs are appended to this COSS as **Appendix 12A(2)**. Other information provided included presentations and slide decks provided by NS Power and its consultants, appended as **Appendix 12A(3)**, jurisdictional scans, appended as **Appendix 12A(4)**, and memorandums, appended as **Appendix 12A(5)**. [Emphasis in original]
>
> [Exhibit N-9, p. 7]

[577] Exhibit N-9 also included information about the cost-of-service models run throughout the consultation process, responses to information requests, presentations, jurisdictional scans, memos and a formal report from NS Power's cost-of-service study consultant, Elenchus.

[578] NS Power's proposed methodologies are listed in Table 2 in Elenchus' report:

Table 2 – Summary of NS Power Proposed Methodology

	Status Quo	Change
Generation	• Allocation except for treatment of purchased power	• No initial classification to energy for environmental and fuel conversion reasons • Use system load factor[5] for classification of all generation, including purchased power • Refunctionalize radial-to-generation from Transmission • Create new storage sub-function • Allocate non-fuel, energy related costs of all purchased power monthly
Transmission	• Bulk Power substations refunctionalized to distribution • Allocation	• Refunctionalize radial-to-generation to Generation • Classify all Transmission as 100% Demand • Create new storage sub-function • No distinction between EHV and HV
Distribution	• Sub-functions • Classification • Allocation	• Create new storage sub-function
Other	• Retail classification & allocation	• General Plant review • Cost allocation applicable to PHP above-the-line[6]
		• DSM rate rider – all DSM costs assigned directly. No system benefit allocation. • DDA methodology • New line losses

[Exhibit N-9, PDF, pp. 1675-1676]

[579] The proposed changes to NS Power's cost-of-service methodologies are described in more detail in Exhibit N-9, Appendix 12A, Part 5.0 and Appendix 12B. The following is a summary of these changes:

> Classification of Generation Costs by System Load Factor
> NS Power's current approach to the classification of generation-related fixed costs such as depreciation and financing costs is to first classify environmental and fuel conversion-related capital costs to energy. A

secondary step classifies peaking assets 100% to demand, wind assets using effective load carrying capability, and categorizes the remaining generation assets using the system load factor. NS Power proposes to end the initial classification of environmental and fuel conversion-related capital costs and to classify all generation assets using the system load factor.

Fuel Adjustment Mechanism Related Cost Sub-Functionalization

Fuel adjustment mechanism related purchases that provide firm capacity will be classified between energy and demand based on the system load factor, while purchases that provide no capacity, such as non-firm imports, will be classified 100% to energy. This will align purchased power agreements providing firm capacity with the treatment of generation assets and recognizes that non-firm purchased power agreements provide energy only.

Classification of Transmission Costs 100% to Demand

NS Power currently uses the system load factor to classify transmission rate base and costs to energy and demand. To reflect anticipated need for increased investment in the transmission system, reduced dependence on coal fired generation in Cape Breton, increased wind generation and a shift away from radial to network system design, NS Power proposes to classify transmissions costs 100% to demand.

Transmission Links to Other Systems

NS Power proposes that transmission links to other systems, such as interties with the grids of other provinces, should generally be functionalized 100% to transmission and therefore classified 100% to demand. NS Power notes this does not have an immediate impact because this category of asset does not currently exist in its rate base.

Removal of the Distinction between Extra High Voltage and High Voltage

NS Power proposes to remove its current distinction between extra high voltage and high voltage and apply a single sub-function for these items. NS Power said there is no real separation between the two systems and this approach would be simpler.

Treatment of Battery Storage

Battery storage is presently functionalized to transmission, but NS Power proposes that battery storage should be considered on a case-by-case basis to determine if the asset is primarily supporting a generation, transmission or distribution function. NS Power noted that the grid scale batteries currently being developed will primarily serve generation, so they are proposed to be functionalized to generation and to be classified based on the system load factor.

Changes to Open Access Transmission Tarriff to Align Bundled and Unbundled Service

NS Power said methodological differences in how rates are set for transmission service in the unbundled market under the Open Access Transmission Tariff (OATT) and the bundled market under its cost-of-service study result in customers paying different amounts for the same transmission service. To align the cost of transmission service between the bundled and unbundled services more closely, NS Power proposes that:

- Transmission revenue requirement applicable under the OATT be set the same as under the cost-of-service study methodology.
- Cost-of-service transmission costs be classified 100% to demand.
- Transmission usage in OATT rate calculations reflect forecasted test year usage.

Radial to Generation

NS Power proposes that radial-to-generation assets, as defined under the OATT, be re-functionalized from transmission to generation in the cost-of-service study for consistent treatment of these assets under the transmission pricing methodologies in the bundled and unbundled markets and to better align with other North American utilities and the Federal Energy Regulatory Commission's pro forma OATT design that provided the foundation for NS Power's OATT.

Demand Side Management Rider

Demand side management costs are currently allocated as 75% to the cost of programs undertaken for the rate class and 25% to the system benefit of the programs. NS Power is proposing to remove the allocation to system benefit, so that 100% of the program costs will be allocated to the benefiting class.

Treatment of Port Hawkesbury Paper as an Above-the-Line Customer

Port Hawkesbury Paper is currently served under a below-the-line rate with a term ending on December 31, 2026 (2025 NSEB 16). In the cost-of-service studies for 2026 and 2027, PHP has been modeled as taking service under an above-the-line rate with the following load characteristics:

- Firm load of 8 MW at the three coincident peaks (3CP) in December, January, and February;
- Total load (firm plus interruptible) of 65 MW at the 3CP; and
- Energy set using PHP forecast net of projected supply from the PHP Goose Harbour Lake Wind Farm.

General Plant
General plant primarily consists of NS Power's investment in facilities, such as buildings structures and grounds, communication equipment, vehicles and information technology infrastructure. Currently, costs are apportioned to generation, transmission and distribution, based on the relative net book value of these three service areas. NS Power proposes that general plant in projects above $1 million be allocated to any clear and identifiable function. For example, vehicle costs are attributable to transmission and distribution far more than generation, so the utility proposes that these costs be allocated between transmission and distribution. The portion of costs to be allocated between each function would be determined by using allocators such as operating costs and rate base.

Decarbonization Deferral Account
NS Power considers its approved decarbonization deferral account to be a rate stabilization tool and proposes that it be classified and allocated in the same manner as other rate stabilization tools.

[580] Relative to NS Power's existing cost-of-service methodologies, the proposed changes negatively impact residential customers. While the costs allocated to almost every other rate class are lower under the proposed methodology, they are approximately $26 million higher for the domestic class in 2026 and $25.3 million in 2027 (NSEB IR-127 [Exhibit N-27, pp. 537-538]).

[581] The parties to the settlement agreement included the following terms relating to cost-of-service methodology used to determine rates for 2026 and 2027:

Cost of Service ("COS")	a) The COS as set out in the Draft GRA will be included in the 2026-2027 GRA and put forward for approval, subject to the following: (a) use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026 and in which parties are free to take any position they so choose; (b) NS Power will collect and disclose the data outlining the extent to which PHP uses, relies upon and/or benefits from the High Voltage transmission system and in any proceeding to determine rates for PHP after the 2026-2027 test period, Parties may make submissions regarding the extent to which PHP is to be responsible for any costs of the High Voltage transmission system; and (c) the appropriate apportionment of assessment costs from the Maritime Link as between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after the 2026-2027 test period.

[Exhibit N-27, NSEB IR-001, Attachment 1, p. 10]

[582] Carolyn Palmer, Synapse Energy Economics, was engaged by Board counsel to review NS Power's cost-of-service study. In her evidence, Ms. Palmer expressed concern about the way that portions of NS Power's distribution system were classified as customer related. She also had concerns about other proposed changes to NS Power's proposed cost-of-service methodologies, but she did not provide specific evidence about those concerns because of the settlement agreement. Indeed, despite her recommendations, Ms. Palmer did not specifically oppose the settlement agreement but said these issues should be reviewed:

> **Q. Considering the consensus agreement in this GRA, what do you recommend regarding the Company's COSS methods?**
>
> **A.** While I do not support several of the Company's COSS methodologies, particularly the use of the minimum system method for classifying distribution system costs, I recognize that the parties have overcome their own concerns with the proposed methodologies to reach a settlement in this case and I therefore do not oppose their settlement agreement in this GRA. However, I believe that the COSS proposals contained within the settlement should be treated as case-specific and non-precedential in future cases. Therefore, I recommend that the Board find that certain COSS methodologies put forward in this case must be revisited in the next GRA. …
>
> [Exhibit N-37, pp. 17-18]

[583] In its closing submissions, Renewall Energy Inc. expressed concern about what it considered to be inconsistencies between NS Power's cost-of-service methodologies and the methods used to determine Open Access Transmission Tariff (OATT) charges.

3.8.1 Findings

[584] For the purposes of setting rates in this proceeding, the Board accepts the proposed cost-of-service changes and the cost-of-service studies presented in this proceeding, except NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs. This issue is discussed in more detail below.

[585] The Board also directs NS Power to address the additional cost-of-service concerns raised by Ms. Palmer in its application to the Board later this year, in addition to the minimum system versus basic customer method debated for allocating distribution system costs. NS Power is also directed to further address the issues raised by Renewall if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator. These issues are also further discussed below.

3.8.2 Minimum System v. Basic Customer Methods

[586] NS Power's cost-of-service study classifies portions of its distribution system as customer-related using the minimum system method. Under this approach, a minimum system study estimates what the cost of a distribution system would be if all poles, fixtures and wires were sized to minimum specifications. The costs of this hypothetical system are deemed to be customer-related costs. The remaining costs of the distribution system are considered to be demand-related.

[587] NS Power submitted that minimum system or zero-intercept studies are generally used for classifying distribution system costs in Canada. Two jurisdictional scans were included in the evidence before the Board in this proceeding. The first was in evidence filed by Concentric Energy Advisors on behalf of NS Power in its last general rate application, and was included in the engagement process materials for the cost-of-service study filed in this matter. The results from that assessment are reproduced below:

Figure 1: Canada Results Summary

Utility	MSS Used?	Poles, Towers and Fixtures	Conductors	Line Transformers
Nova Scotia Power (Current)		PRI: 27% Customer, 73% Demand; SEC: 50% Customer, 50% Demand	PRI Overhead/Underground: 27% Customer, 73% Demand; SEC Overhead/Underground: 50% Customer, 50% Demand	100% Demand
Nova Scotia Power (Proposed)	Yes	PRI: 76% Customer, 24% Demand; SEC: 70% Customer, 30% Demand	PRI Overhead: 38% Customer, 62% Demand; SEC Overhead: 83% Customer, 17% Demand; PRI Underground: 17% Customer, 83% Demand; SEC Underground: 82% Customer, 18% Demand	100% Demand
ATCO Electric	Yes	55% Customer, 45% Demand	Overhead: 70% Customer, 30% Demand; Underground: 70% Customer, 30% Demand	55% Customer (Non-Rural); 60% Customer (Rural); (50% Rural Allocated)
BC Hydro	No	50% Customer, 50% Demand	50% Customer, 50% Demand	50% Customer, 50% Demand
Fortis BC Energy	Yes	81% Customer, 19% Demand	65% Customer, 35% Demand	69% Customer, 31% Demand
Maritime Electric	No	50% Site (Customer), 50% Demand	50% Site, 50% Demand	40% Site; 60% Demand
New Brunswick Power	No	50% Customer, 50% Demand	50% Customer, 50% Demand	25% Customer, 75% Demand
Newfoundland Power	Yes	37% Customer, 63% Demand,	37% Customer, 63% Demand	28% Customer, 72% Demand
Ontario	No	60% Customer if Density is < 30 customers per kM of lines, 40% Customer if Density between 30 and 60 customers per kM of lines, 35% Customer if Density between > 60 customers per kM of lines, or 30% Customer if Density is between > 60 customers per kM of lines		
SaskPower	Yes	70% Customer, 30% Demand	70% Customer, 30% Demand	35% Customer, 65% Demand

[Exhibit N-9, PDF pp. 62-63]

[588] The other was prepared by Elenchus and is also found in the engagement process cost-of service materials filed in this matter:

Utility	Transformers	Primary	Secondary
BC Hydro	Judgement (50%/50%)	Judgement (100% Demand)	Judgement (50%/50%)
SaskPower	Minimum System		
Manitoba Hydro	PUB Order (100% Demand)		
Ontario Distributors	Judgement (with consideration of Minimum System analysis)		
Hydro Quebec	Minimum System		
NB Power	Judgement (with consideration of Minimum System and Zero-Intercept analyses)		
NS Power	100% Demand	Minimum System	
Maritime Electric	Judgement (60% Demand)	Judgement (50%/50%)	
NL Power	Zero-Intercept	Minimum System	

[Exhibit N-9, PDF p. 1471]

[589] Ms. Palmer agreed that NS Power's use of the minimum system method is not unique and that it is used in other jurisdictions throughout Canada. However, she did not believe this means it is a reasonable method to use for classifying distribution infrastructure.

[590] Ms. Palmer said the minimum system method does not align with NS Power's definition and treatment of customer costs because these costs do not vary directly with the number of customers. She said:

> For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because no significant demand is being added by the new customer. If, however, the new customer were to add a substantial amount of additional demand, then distribution system upgrades would be required, increasing costs. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic area that an incremental customer impacts distribution system costs independently from the customer's level of demand.
>
> This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer's demand) unless the system must be expanded to a new geographic area. Indeed, NS Power states that the customer-related portion of feeder investment "is driven by the need to bring electric service to geographically dispersed customer locations." Thus, there is little justification for classifying costs in these accounts as customer-related.
>
> [Exhibit N-37, pp. 6-7]

[591] Ms. Palmer said the number of poles and the amount of wire required to serve customers is more likely to vary based on the distance of development from other infrastructure and that geography is not necessarily well-correlated with the number of

customers. She said the minimum system method does not include a measure to account for geographic dispersion.

[592] Ms. Palmer recommended classifying distribution costs using the basic customer method, as described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*. She said this method was used across North America. Following this method, only costs associated with services, meters, meter reading and billing are generally classified as customer-related.

[593] Ms. Palmer considered that the use of the minimum system method overstates the costs classified as customer-related. She also noted that because the residential class has more customers than other classes, customer-related costs are far more heavily allocated to residential customers.

[594] In response to NSEB IR-128, NS Power calculated the impact on costs allocated to customer classes using the basic customer method. The result of this analysis showed that using the basic customer method shifted about $30 million in costs away from the residential class to other rate classes, with most of that difference moving to the general service class. In response to Undertaking U-5, NS Power provided calculations showing the impact on proposed rate changes in this proceeding if the basic customer method was used instead of the minimum system method (along with certain other corrections), as set out below:

	Proposed COSS Methodology		Modified COSS Methodology as per U-5		Variance	
	Smoothed		Smoothed		Smoothed	
Customer Class	2026	2027	2026	2027	2026	2027
Domestic	3.8	4.1	2.2	2.8	(1.6)	(1.3)
Small General	3.6	3.9	1.7	2.4	(1.9)	(1.4)
General	(0.2)	0.6	3.1	3.5	3.3	2.9
Large General	(4.5)	(3.1)	(2.2)	(1.3)	2.3	1.8
Large General	(0.5)	0.3	3.0	3.3	3.5	3.0
Medium Industrial	(6.5)	(4.8)	(3.1)	(2.2)	3.4	2.5
Large Industrial	(7.0)	(4.7)	(6.0)	(3.8)	0.9	0.9
Municipal	1.7	3.1	3.0	3.9	1.3	0.8
Unmetered Classes	7.9	7.2	2.9	3.1	(5.0)	(4.1)
Total	1.7	2.4	1.7	2.4	(0.0)	(0.0)

[Exhibit N-76, p. 1]

[595] As can be seen from the table above, the change to the basic customer method would reduce the proposed increases for the domestic, small general and unmetered rate classes, but increase the rate changes for the rest of NS Power's above-the-line rate classes. However, the large general, medium industrial and large industrial classes still see overall rate reductions in both test years. The Board understands the second reference to "Large General" in the exhibit is an error and should be "Small Industrial".

[596] Mr. Blair suggested that the number of recognised methods for allocating distribution system costs was limited:

> **Q.** Is there a — I know it was referenced in Elenchus's evidence, as well as perhaps Ms. Palmer's evidence, there is reference to I think the Zero Intercept method. Is that kind of a hybrid sort of methodology that would sort of fall between the Minimum System method and the Basic Customer method?
>
> **A.** (Blair) It's really more like the Minimum System method, but instead of it being a Minimum System that has some delivery capacity it's a hypothetical system that reaches every customers but doesn't have any delivery capability at all.
>
> **Q.** Okay. And are those really the three basic methods that are primarily used in cost-of-service studies?

> **A.** (Blair) Yes, that's right. And there's often multiple ones considered and then some kind of judgmental percentage applied to them is necessarily the results of each one.
>
> [Transcript, January 7, 2026, p. 155]

[597] In response to questions from the Board at the hearing, Mr. Blair also agreed that the basic customer method would classify the smallest amount of distribution system costs as customer-related and the minimum system method would classify the highest amount.

[598] Both Mr. Blair and Ms. Palmer agreed that the classification of distribution system costs is one of the most controversial aspects of determining cost-of-service. This is likely because these costs cannot be neatly identified as being driven primarily by an increase in customers or in demand.

[599] Although Mr. Blair considered the geographic size of the distribution system to be more closely aligned with an increase in customers than Ms. Palmer, he acknowledged that this is an area where costs are "not exactly caused by one of the three usual allocators of customer, energy and demand". Similarly, in response to questions from NS Power at the hearing, Ms. Palmer agreed that costs relating to the geographic dispersion of the system were not well correlated with an allocation based on either the number of customers or demand.

[600] Professor Bonbright noted this problem in *Principles of Public Utility Rates*:

> The really controversial aspect of customer cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else

> with the links of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating costs to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile square mile quote). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatsoever in the costs of a minimum sized distribution system.
>
> While, for the reason just suggested, the inclusion of the costs of a minimum size distribution system among the customer related cost seems to us clearly indefensible, its exclusion from the demand related cost stands on much firmer ground. For this exclusion of minimum size distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on the system as measured by peak load.
>
> But if the hypothetical costs of a minimum size distribution system is properly excluded from the demand related costs for the reason just given, while it is also denied a place among the customer costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any other cost categories.
>
> In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts. Sterzinger (1981) is critical of this practice and recommends that to avoid the overcollection of costs from low-use residential customers, regulators should classify distribution costs as demand costs. Neither of these procedures can be justified as a cost allocation in the sense of directly assignable costs, for they are nonassignable.
>
> Allocation, in whole or in part, would be at least theoretically possible if a customer density parameter were added to the three traditional cost components. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition (see Watkins, 1921, p. 212 and Havlik, 1938, Chapter 8 and Appendix A). [Emphasis added]
>
> [pp. 491-492]

[601] Although Ms. Palmer recommended the use of the basic customer method, she recognized that the parties to the settlement agreement had agreed to defer that matter for a more detailed consideration in 2026. On that basis, she does not oppose the

settlement agreement, although she urged the Board to direct that other proposed changes to NS Power's cost-of-service methodologies also be considered in that process. She also suggested that, if the Board were to allow the classification of distribution system costs using a minimum system study, it could consider doing so only for the secondary distribution system and classifying primary distribution system costs to demand. Additionally, she submitted an adjustment should be made to recognize the minimum system's peak load carrying capability. These issues are discussed in more detail later in this decision.

[602] In their closing submissions, parties to the settlement agreement urged the Board accept the terms of the settlement agreement and allow the proposed changes to the cost-of-service methodology to stand, pending an application later this year which would address the classification of distribution system costs under the minimum system or basic customer method for future proceedings. They emphasized the extensive nature of the engagement process leading to the settlement agreement and the fact that unresolved issues relating to this matter are going to be addressed in a another proceeding later this year.

[603] The Industrial Group submitted that Ms. Palmer's evidence was narrow and did not provide a proper basis to make the cost-of-service changes she recommended at this time. The Industrial Group also emphasized the impact such changes would have on non-residential customers:

> Synapse's evidence on the Basic Customer method was shown on cross-examination to be narrow, lacking both a jurisdictional scan and Nova Scotia–specific analysis.
>
> The record further shows that the Basic Customer approach is scarcely used in Canada—Manitoba being the only example, and even there it is now under review, with evidence filed outlining significant flaws in the method. Those criticisms include that even the smallest customer drives meaningful distribution costs, and that ignoring minimum system

> requirements distorts cost causation. While Ms. Palmer characterizes the minimum-system method as flawed, it remains recognized in the NARUC Cost Allocation Manual.
>
> …
>
> Response to Undertaking U-5 provides the rates resulting from this single proposed change. The residential class would see a reduction of 1.6% in 2026 (smoothed rates) relative to what has been applied for but each of General, Large General and Medium Industrial would increase approximately 3.5%. …
>
> The Board has been clear that rate impacts cannot be assessed in isolation. All-in customer bill effects, including base rates, the FAM AA/BA rider, and the DSM rider, should be considered together. The full scope of rates and riders were considered by the customer representatives and informed the Consensus Agreement.
>
> If the Board were to modify aspects of the COSS allocation methodology, it would have a disproportionate impact on certain rate classes. Modifications would benefit residential classes, who are experiencing a higher base rate increase in the GRA but significantly burden other classes, including the General rate class and the Medium and Large Industrial classes, which will have an overall higher rate increase for 2026 once the riders are considered.
>
> Given the incomplete record, introducing methodological changes at this time would be premature and could lead to unintended rate consequences. The parties intentionally carved out the Minimum System issue for a separate, dedicated proceeding in 2026 to allow appropriate time for expert analysis, proper collection of data, evaluation of alternative methods, and a complete evidentiary process. [Emphasis added] [Footnotes omitted]
>
> [Industrial Group Closing Submissions, pp. 7-8]

[604] These sentiments were shared by the MEUs. The MEUs also noted that the use of the minimum system method was of particular interest to them because they also used it to determine rates for their customers:

> As the Board is aware, the MEUs currently use the Minimum System methodology as part of their own COS methodologies in developing rates for their customers. Like NS Power and its consultant, Elenchus, the MEUs support the use of the Minimum System methodology. Clearly, the issue is one of the most controversial aspects in cost allocation in utility rate-making, and has been that way “forever”, as the Chair suggested in his questions to NS Power’s COS Panel. The MEUs recognize that Synapse, an American consulting firm, has repeatedly expressed its preference for use of the Basic Customer method in multiple Nova Scotia proceedings in recent years. But there is also no doubt that the Minimum System method is one of the recognized cost-of-service methods used in Canada, and it has been approved for use in Nova Scotia for all electric utilities for decades.
>
> [MEUs Closing Submissions, p. 2]

[605] In its submissions, the Consumer Advocate noted:

> The Consumer Advocate shares Ms. Palmer’s concerns regarding the Minimum System Method, and through the Settlement Agreement, and resulting GRA, NS Power has agreed that the use of the Minimum System Method after the test years will be the subject of a

> separate proceeding before the Board that will be initiated later this year by an application from Nova Scotia Power. The Consumer Advocate continues to support that approach. As with any aspect of the GRA, it is up to the Board to determine if this is a sufficient response to the issue or if some other remedy is required to provide for rates that are "just and reasonable."
>
> [Consumer Advocate Closing Submissions, p. 8]

[606] The Nova Scotia New Democratic Party Caucus and the Nova Scotia Liberal Party Caucus urged the Board to implement Ms. Palmer's recommendation to adopt the basic customer method to classify distribution system costs. The New Democratic Party submitted that this method would be "less biased against residential customers, so that Nova Scotian households don't bear an outsized burden of any increase". The Liberal Party submitted switching to the basic customer method "could reduce the increase faced by customers".

[607] NS Power submitted that the COSS filed in support of its rates in this proceeding provided the most appropriate basis for allocating costs among customer classes following cost causation principles.

3.8.2.1 Findings

[608] Under a cost-of-service model, the objective is to fairly allocate costs to customers based on cost causation. This has been a chronically difficult thing to do for distribution system costs. It would be inappropriate to direct the use of the basic customer method to classify distribution system costs simply to reduce the rate increase for residential customers. It would be just as inappropriate not to do so because of the impact that would have on other customers (with or without rate rider impacts). However, the parties did not fully press this issue in this proceeding due to the settlement agreement and the Board requires more information to further assess the cost causation basis for adopting the basic customer method. As explained below, these issues will be brought before the Board for further consideration in a cost-of-service proceeding later this year.

[609] From the evidence in this proceeding, both cost-of-service experts acknowledge that neither the minimum system method nor the basic customer method is perfect because distribution system costs are not correlated well enough with either the number of customers or the demand on the system by those customers. It is somewhat telling that the same problem discussed by Professor Bonbright nearly 40 years ago continues today.

[610] While the Board supports settlement agreements, it is very concerned that in the face of the other significant changes that have been proposed to the cost-of-service, NS Power has proposed to leave this issue unaddressed in this proceeding for what appears to the Board to be the expediency of bringing forward a consensus position to support its general rate application. Unfortunately, the Board is now in a position where it finds that neither of the proposed methods for classifying distribution system costs is wholly adequate. Based on the closing submissions filed in this proceeding, it appears there may be more that the parties would like to say.

[611] One option to address this problem would be to require this issue to be further addressed before the Board rendered a final decision in this matter. This would, of course, delay the implementation of new rates. Were it not for the concerns about NS Power's ability to maintain its credit metrics well enough to avoid a costly downgrade (discussed in more detail elsewhere in this decision), this may very well have been the result. NS Power should bear this in mind in the event it brings forward settlement agreements in the future that leave significant issues both unaddressed in the agreement and proposed to remain that way in the final decision in the matter.

[612] The Board considers that broader participation from customer groups is necessary to provide a more appropriate basis for determining this question and therefore finds it is not able to resolve this issue in this proceeding. The Board therefore accepts that this will be further considered by NS Power and brought back to the Board later this year when it can be more openly considered and debated. While this is not an entirely satisfactory result, the Board takes some comfort that, despite her position, Ms. Palmer was prepared to accept the consensus position on this point – subject to a caveat that will be addressed later in this decision.

3.8.3 Primary Distribution System

[613] If the basic customer method is not used to allocate distribution system costs between customer and demand, then Ms. Palmer recommends that the primary distribution system be classified 100% to demand. Ms. Palmer expressed concern that the minimum system methodology used in the cost-of-service study included NS Power's primary electric system distribution lines notwithstanding that the residential customer class likely does not receive service directly at primary voltage. Ms. Palmer submitted that primary infrastructure is shared, is more likely to peak at the same time as system peaks and is likely higher-voltage than the customer-specific equipment (meters and services) directly serving the majority of electricity customers.

[614] According to an analysis undertaken by Concentric in 2022, in advance of NS Power's last general rate application, nearly 65% of distribution system poles were sub-functionalized to primary distribution, while nearly 80% of overhead conductors were found to be part of the primary distribution system:

	Poles	Overhead Conductors	Underground Conductors
Primary - Demand	15%	49%	6%
Primary - Customer	49%	30%	1%
Secondary - Demand	11%	3%	17%
Secondary - Customer	25%	17%	76%

[Exhibit N-9, PDF p. 1225]

[615] Based on the jurisdictional scan that was undertaken by Elenchus and reproduced previously in this decision, NS Power submitted that Saskatchewan, Quebec, and Newfoundland and Labrador use the minimum system method for both primary and secondary distribution systems, while the approaches used in Ontario and New Brunswick are grounded in judgement with some consideration of the minimum system.

3.8.3.1 Findings

[616] As with the discussion about the use of the minimum system method or the basic customer method, the Board finds that a more satisfactory resolution of this issue would result from a broader debate about this issue. The Board therefore directs that this issue be specifically analysed and considered in the engagement process intended to address the appropriate classification of distribution system costs. To be clear, the matter should not be resolved based on a jurisdictional scan alone. The Board expects the issues identified by Ms. Palmer to be comprehensively addressed in the proceeding. In particular, this should include but not be limited to the manner in which the primary distribution system is used and shared by the various customer classes, the extent to which residential customers receive service directly at primary voltages and whether their equipment can be served at those voltages, and the demand on the primary distribution system relative to the system peak.

3.8.4 Peak Load Carrying Capability Adjustment

[617] Ms. Palmer also recommended that a peak load carrying capability adjustment be applied to account for the demand component served by the minimum system, if the basic customer method is not used to classify distribution system costs between customer and demand. She noted that poles and wires of any size have a load-carrying capacity that will necessarily serve a portion of a customer's demand and submitted this should be recognized. In response to questions from Board Counsel at the hearing, NS Power agreed that even a theoretical minimum system has load carrying capability and will necessarily serve a portion of customer demand.

[618] Ms. Palmer advised that a peak load carrying capability adjustment of 0.4 kW/customer is applied for the assumed peak load carrying capability of the minimum system in Ontario. She also said that in its most recent rate cases, Excel Energy in Minnesota and South Dakota had assumed a peak load carrying capability of 1.5 kW/customer for the minimum system and applied this adjustment to its distribution capacity cost allocation factors. She also noted that National Grid, in New York, recently proposed not allocating any demand-related costs for the minimum system distribution infrastructure to residential and small commercial customers on the premise that the minimum system would be able to meet the peak load for all or almost all customers in these classes.

[619] Ms. Palmer recommended that NS Power implement a peak load carrying capability adjustment for any infrastructure cost classified using its minimum system study. She acknowledged that a specific adjustment would require thoughtful analysis but, in the absence of a specific calculation, recommended that each customer class be

credited with 1.5 kW/customer to the non-coincidental peak demands used for determining minimum system demand allocators.

[620] Based on her pre-filed evidence and her responses to questions at the hearing, it is apparent that Ms. Palmer's recommended credit was intended to be used as a proxy until NS Power calculated a more accurate peak load carrying capability adjustment. As she explained at the hearing:

> **Q.** And you recommend 1.5 kilowatt per customer, which is outside of the range of what we reviewed from Ontario. So could you confirm, and perhaps you explained to my friend, but I'm still not clear about exactly how you came up to that number.
>
> **A.** Like I discussed with Ms. Power, there are kind of three examples that I've seen that I put in my testimony; the .4 from Ontario, the 1.5 from Minnesota and South Dakota, and then New York State's, or National Grid in New York State, proposing to simply assign no demand costs to it's residential and small commercial customers.
>
> And this seems to be kind of in the middle of that. There's the range of adjustments that I'm aware of that I presented, and this is kind of a middle route. I've acknowledged it's an approximation and that it will be superior to have Nova Scotia Power's analysis when available.
>
> [Transcript, January 13, 2026, pp. 1311-1312]

[621] In response to Undertaking U-6, NS Power calculated the impact on rates if a 1.5 kW/customer adjustment was applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators of the distribution system costs. The result was to shift responsibility for about $7 million in costs away from the residential class to other rate classes, with most of that difference moving to the general service class. As shown in the table from the undertaking response, reproduced below, applying such a peak load carrying capability adjustment would reduce the proposed increases for the domestic, small general and unmetered rate classes, but increase the rate changes for the rest of NS Power's above-the-line rate classes. However, the large general, medium industrial and large industrial classes still see overall

rate reductions in both test years. The Board understands the second reference to “Large General” in the exhibit is an error and should be “Small Industrial”.

	Proposed COSS Methodology		Modified COSS Methodology as per U-6		Variance	
	Smoothed		Smoothed		Smoothed	
Customer Class	2026	2027	2026	2027	2026	2027
Domestic	3.8	4.1	3.2	3.7	(0.6)	(0.4)
Small General	3.6	3.9	3.4	3.8	(0.2)	(0.1)
General	(0.2)	0.6	0.9	1.4	1.0	0.9
Large General	(4.5)	(3.1)	(3.7)	(2.5)	0.7	0.7
Large General	(0.5)	0.3	0.5	1.1	1.0	0.8
Medium Industrial	(6.5)	(4.8)	(5.6)	(4.0)	0.9	0.7
Large Industrial	(7.0)	(4.7)	(6.6)	(4.3)	0.4	0.4
Municipal	1.7	3.1	2.2	3.4	0.5	0.3
Unmetered Classes	7.9	7.2	7.0	6.3	(0.9)	(0.9)
Total	1.7	2.4	1.7	2.4	(0.0)	0.0

[Exhibit N-77, p. 1]

[622] In response to questions from NS Power at the hearing, Ms. Palmer agreed that the peak load carrying capability adjustment used in Connecticut was heavily influenced by the capacity adjustment associated with line transformers. The capacity adjustments for all other equipment were less than 0.4 kW/customer. Ms. Palmer also acknowledged that NS Power’s cost-of-service methodology allocates transformers as 100% demand-related.

[623] In its closing submissions, NS Power submitted that the implementation of a peak load carrying capability adjustment would have significant consequences for other rate classes and that such a change “should not be taken lightly”. NS Power emphasized that determining an appropriate peak load carrying capability adjustment for its minimum system required thoughtful analysis and that there was no basis in the evidence in this proceeding to assign an adjustment of 1.5 kW/customer at this time. As noted already, the other parties to the settlement agreement expressed concerns about implementing

Ms. Palmer's recommendations given the balance that was achieved under the settlement and the impact that these recommendations would have on non-residential customers, due to the shifting of costs and the impact of rate riders that will be applied in addition to the base rates determined in this general rate application.

3.8.4.1 Findings

[624] Notwithstanding the settlement agreement, the Board finds that it is appropriate to direct NS Power to implement a load carrying capability adjustment in this proceeding. Unlike the evidence relating to the use of the minimum system method or the basic customer method for classifying distribution system costs, where neither approach seemed sufficiently supported by the evidence in this proceeding, it appeared that both cost-of-service experts (and NS Power) agreed that a minimum system has some load carrying capability. The Board finds this should be addressed now, rather than wait for the process planned for later this year, and then not be implemented for another year or more. Further, the issue of a load-carrying capability adjustment must be decided on its own merits and not depending on whether it reduces rate increases for some customers classes or puts upward rate pressures on other classes (with or without rate rider impacts).

[625] The evidence uniformly supported that, although subject to some complexity, it was possible to determine more precisely the load carrying capability of the minimum system assessed for NS Power’s system. As noted, NS Power submitted there was no basis in the evidence in this proceeding to assign an adjustment of 1.5 kW/customer at this time. This is true because evidence of this nature was not provided by NS Power in this proceeding. At the same time, there is evidence that a minimum system has some load carrying capability, so NS Power’s election to assign no

adjustment at all would, on the limited evidence that is before the Board in this matter, appear to be the least supported approach.

[626] Based on the information provided in this proceeding, the Board directs NS Power to implement a load carrying capability adjustment of 0.4 kW/customer to its minimum system method. The Board finds that the number used in Ontario is an appropriate proxy pending a more precise determination by NS Power. In doing so, the Board accepts that the 1.5 kW/customer adjustment used by Excel Energy is influenced by the capacity associated with line transformers that are already classified fully to demand in NS Power's case, making it a less appropriate proxy. NS Power is directed to make this adjustment in a compliance filing in this matter.

[627] The Board also directs NS Power to undertake the analysis necessary to calculate the load carrying capability of its minimum system. This must be done before NS Power engages with customer representatives in the proceeding contemplated in the settlement agreement, and this analysis must be included in the application resulting from that process that NS Power will file with the Board later this year.

3.8.5 Other Cost-of-Service Issues Raised by Synapse

[628] As noted already in this decision, in addition to her concerns about the use of the minimum system method to classify distribution system costs, Ms. Palmer had concerns about certain other proposed changes to NS Power's cost-of-service methodologies. However, rather than elaborate on these concerns in her evidence, and recognizing that the settlement agreement contemplated a future proceeding before the Board to address the use of the minimum system methodology after the 2026-2027 test period, she elected instead to recommend that the Board direct that the future proceeding also include an examination of other cost-of-service changes as well. These include NS

Power's departure from its current approach to classifying generation costs, in which it now proposes to classify all generation assets using the system load factor; NS Power's departure from its current approach to classifying transmission costs, in which it now proposes to classify 100% of transmission costs to demand; and the potential for NS Power to use more granular and temporal allocators (noting that further data analysis and discussion would likely be worthwhile in considering moving away from the three coincident peak generation and transmission demand cost allocation and non-coincident peak distribution demand cost allocation).

[629] In response to questions from Board Counsel at the hearing, NS Power suggested that the settlement agreement contemplated that the only outstanding issue that would be addressed in the future proceeding noted in the agreement was the use of the minimum system method beyond the test years in the current general rate application:

> **Q.** So N-37, page 20 in the PDF, line 16. Here Ms. Palmer has identified additional Cost-of-Service Study methods that she thinks should be reviewed as part of whatever future process occurs, and she lists out the three areas here. Has Nova Scotia Power had a opportunity to consider those, and do you have a position on whether you agree with those being part of consideration in future cost-of-service matters?
>
> **A.** (Williams) Thanks, Mr. Mahody. I think what the Settlement Agreement does is it expressly identifies Minimum System as being subject to what we would see as a standalone application or matter that we would bring to the Board in 2026, and that's what's described in the Settlement Agreement. And as it says in the Settlement Agreement, any party may take any position they so choose.
>
> Subsequent to the test period, the '26-'27 test period, we would not — our expectation is not that the Settlement Agreement or the positions that parties have taken in relation to the Settlement Agreement in any way binds them, and all cost-of-service issues would be before the Board for consideration at the next General Rate Application or the next standalone cost-of-service proceeding.
>
> That said, I think there is an expectation -- I know there is an expectation from Nova Scotia Power, and I would think there's a similar expectation from all parties, that we're not redoing the same extensive cost-of-service process that we just undertook in relation to all cost-of-service matters in subsequent proceedings. I would expect that we do get some value out of what we just went through, but certainly the Minimum System is one that was identified as being for further consideration.

> **Q.** Okay. And so back to Ms. Palmer's three additional methods that she is recommending you reviewed. Do you agree that the next point, Cost-of-Service Study — a full Cost-of-Service Study is being undertaken, that those matters should be considered?
>
> **A.** (Williams) I think the next time a full Cost-of-Service Study was undertaken all matters would be out there. But as I said, no-one's bound as a result of this process or the agreement, but certainly the expectation would be that we've reached common ground on certain aspects of these.
>
> I think where my uncertainty in terms of the recommendation lies is when you read from line 9 it says:
>
> I recommend that the Board expressly state that not only should the [minimum system] methodology be subject to a future proceeding and determination...but that the same requirement should apply to several other [cost-of-service] methods...
>
> And so if Ms. Palmer's intention there is to include these other methods in the 2026 filing that's described and expressly set out in the Settlement Agreement, we would disagree with that recommendation and we would not feel that that's the expectation of Nova Scotia Power. But if she's referring to future cost-of-service studies, then, as I said, I think all issues would be subject to the Board's consideration and assessment in that setting.
>
> [Transcript, January 7, 2026, pp. 127-130]

[630] In its closing submissions, Port Hawkesbury Paper endorsed NS Power's testimony on this point. It also argued that the parties needed certainty and stability about these points:

> Based on the considerable record before the Board, PHP submits that the recommendations made by Synapse at pages 18-19 of its evidence (Ex. N-37) that "several other COSS methods" in addition to the minimum system methodology should be subject to a future proceeding and determination by the Board should not be accepted at this time. The COSS provides the underpinning costs to be collected from the various rate classes, and a level of stability is appropriate in this regard as has historically been the case in Nova Scotia.
>
> [Port Hawkesbury Paper Closing Submissions, p. 6]

3.8.5.1 Findings

[631] It is clear that Ms. Palmer has some misgivings about other aspects of NS Power's cost-of-service methods, but in light of the settlement agreement, she elected to focus on the minimum system vs. basic customer issue and leave the others to the future process she understood was contemplated under the settlement agreement. Although the Board places weight on the fact that informed participants have agreed to a resolution of these issues, when the Board is considering whether it is in the public interest to accept

the settlement agreement, the existence of a settlement agreement is certainly not dispositive of that issue.

[632] The traditional role of Board Counsel and consultants is to ensure that the Board has an appropriate record before it to render a fully informed decision. If Synapse believes these issues are worth raising for the Board to consider, the Board would prefer that it do so, precisely because cost-of-service issues have tended to remain in place for extended periods in this jurisdiction. Therefore, the Board directs NS Power to specifically address the areas of concern identified by Ms. Palmer in the application NS Power expects to file with the Board later this year.

3.8.6 Issues Raised by Renewall Energy Inc.

[633] As mentioned earlier in this decision, in its closing submissions, Renewall said there were inconsistencies between NS Power's cost-of-service methodologies and the methods used to determine OATT charges. Renewall's focus was on the impact of these inconsistencies on rates in the renewable-to-retail market, in which it is currently the only licensed retail supplier. Renewall also highlighted the Board's obligation to appropriately consider the extent to which its decisions support the development of a competitive electricity market under s. 6(2) of the *Energy and Regulatory Boards Act*.

[634] NS Power submitted:

> NS Power applied the approved OATT and COS methodologies, as amended in the Settlement Agreement, to determine the proposed bundled and OATT charges. The transmission costs are allocated to the bundled rate classes based on class contribution to the three winter month peaks of January, February, and December (three coincident peaks, 3CP) whereas allocation of these costs to the open market transmission services of point-to-point and network are done on the basis of their contribution to the twelve calendar months (12CP). The difference in approach to the allocation of transmission costs in these two markets was discussed and accepted by the intervenors to the 2005 OATT founding proceeding. [footnotes omitted]
>
> [NS Power Reply Submissions, p. 26]

[635] One of Renewall's concerns was that the system coincident factor used in the cost-of-service study (78.6%) [Exhibit N-67, Attachment 1, p. 79 of 99] did not match the system coincident factor used in the OATT rate development tables (91.66%) [Exhibit N-17(vi), Figure 5-13]. Renewall noted that using the cost-of-service system coincident factor in the calculation for the monthly billing rate for network service reduced the charge by over 14%.

[636] NS Power said the coincident factors were two different calculations serving two different purposes. It said the factor in the OATT calculations determines system non-coincident demand billing determinants on the basis that the monthly $ per MW charges under the OATT are calculated such that application of the proposed OATT charges yields the OATT revenue requirement. NS Power noted the factor of 78.6% is not used directly in rate calculations.

[637] Renewall also noted that the system peaks in the cost-of-service and OATT calculations do not match. It observed that, for 2026, the OATT calculations assume a coincident peak of 1,778 MW and a non-coincident demand of 1,939 MW [Exhibit N-17(vi), Figure 5-10] (i.e., coincidence factor of 91.7%), while COSS Exhibit 9A suggests a coincident peak of 2,095 MW and a non-coincident peak of 2,667 MW [Exhibit N-67, Attachment 1, p. 79 of 99] (i.e., coincidence factor of 78.6%).

[638] While it did not expect the differences to produce a material impact, Renewall also noted what it considered to be other inconsistencies. For example, it noted that formulas in the cells used to determine the revenue requirement for load following and 10-minute supplemental operating reserve in Exhibit N-17(vii) (Summary Rates, cells B27 and B29) did not appear to be consistent with Exhibit N-17(vi), Figure 6-8. In its reply

submissions, NS Power appeared to accept that the figures in Exhibit N-17(vii) and (ix) (Summary Rates) were incorrect, but said these pertain only to “side calculations” and do not impact the proposed OATT rates.

[639] In concluding its comments in its reply submissions in response to the issues raised by Renewall, NS Power said:

> REI suggests that coincident factors and system peaks drive the transmission and ancillary service components of the OATT, and using the updated COSS would result in lower OATT costs per MW. This is false. As indicated above, the coincidence factors from ‘Exhibit 9a Annual’ are not relevant to the calculation of the OATT rates.
>
> As demonstrated above, the proposed OATT rate calculations are accurate and consistent with the approved methodology. The OATT calculation process has been revised to better align with the COS through the COSS stakeholder consultation process conducted in 2024 and incorporated into the 2026-2027 GRA.
>
> Overall, it does not appear that REI is asking the Board to reject any aspect of the COS as proposed or that REI is challenging the OATT; however, it seems that REI is asking the Board to treat the COS as completely determinative of OATT inputs, rather than as a separate construct.
>
> It is important to note that no complete COS will ever be fully mirrored in the calculation of OATT rates. Further, in the future as outlined in the *More Access to Energy Act*, the Independent Energy System Operator of Nova Scotia (IESO Nova Scotia) will administer the OATT once relevant sections are proclaimed. It will be up to the IESO Nova Scotia to determine how it will incorporate the COS from market entities into the OATT structure.
>
> Differences between COS and OATT inputs do not, in and of themselves, indicate errors or overcollection. NS Power continues to engage with REI through its established monthly check-ins and welcomes all further opportunity to walk through the OATT methodology and assumptions in greater detail and address any remaining questions on these points. [footnotes omitted]
>
> [NS Power Reply to Closing Submissions, pp. 27-28]

3.8.6.1 Findings

[640] Because these technical issues were only raised in closing submissions, the Board has a poor record before it to make an informed decision on these points. As a result, the Board accepts the relevant calculations included in the settlement agreement.

[641] However, Renewall correctly points out that the Board must appropriately consider how its decisions support competition and innovation in the provision of energy resources in the province and the development of a competitive electricity market. In this regard, NS Power's response that "the proposed OATT rate calculations are accurate and consistent with the approved methodology" is not entirely satisfactory. The real question is whether that dated methodology continues to be appropriate.

[642] Although responsibility for the transmission tariff will, at some point, transfer to the Nova Scotia Independent Energy System Operator, it is not entirely clear when that will occur. The most recent information from IESO Nova Scotia suggests an "aspirational timeline" for this transition in the second quarter of 2027. Furthermore, under s. 83 of the *More Access to Energy Act*, SNS 2024, IESO Nova Scotia will inherit the existing transmission tariff at that time, which will remain in force until it is changed by IESO Nova Scotia. Therefore, if NS Power brings forward any application proposing any changes to the OATT between now and when it is transitioned to IESO Nova Scotia, including if NS Power files a general rate application, then NS Power is directed to more fully consider the issues raised by Renewall in that application.

[643] As a final point, the Board notes that Renewall may have been able to raise its concerns about the relationship between the cost-of-service study and the OATT earlier had it had access to information that was not confidential but was only provided in the confidentially filed Excel files marked as Exhibit N-17(C)(i) SR-01 Attachment 1 and Attachment 2. Portable document format (PDF) versions of these files were only provided after the hearing in response to Undertaking U-4. While the Board prefers Excel files with intact formulae when available, if there is confidential information in those files, PDF

versions of those files with appropriate redactions of confidential information must be filed in all cases. NS Power must ensure it does so in all future matters before the Board.

3.9 Rate Design

[644] In its application, NS Power did not propose to introduce new concepts or materially change the design of any of its rates. The parties to the settlement agreement accepted the changes to tariff language and the updating of charges that NS Power proposed. For the most part, other parties raised no concerns about these matters in the evidence or submissions filed with the Board. To the extent not otherwise addressed in this decision or not otherwise requiring changes due to directions provided in this decision, the Board accepts these items as filed.

3.9.1 Innovation

[645] In NSEB IR-132, NS Power was asked to describe any work it has done to develop new or innovative rate designs to leverage more granular data from Advanced Metering Infrastructure (AMI) meters, promote efficient use of system resources, or address emerging or anticipated electricity and energy market changes due to decarbonization, decentralisation of energy resources, or other factors. In its response, NS Power said it was continuing to develop innovative rate structures through several initiatives and remains committed to developing rate designs that promote efficient use of system resources and respond to evolving market dynamics.

[646] NS Power noted that AMI infrastructure was instrumental in supporting both cost-of-service studies and ongoing pricing innovation work. NS Power referenced its time-varying pricing (TVP) program and the development of customer energy management systems to provide customers with tools and information to better understand their energy use and evaluate rate options that may be suitable for their usage

patterns. NS Power also noted that it expanded its TVP program to include a multi-unit residential building time-of-use pilot tariff. It said it also supports programming through the provision of AMI data to EfficiencyOne (E1) for demand side management activities and demand response programming. NS Power also cited its work with Port Hawkesbury Paper to design a rate to both provide service to that customer and leverage the characteristics of that customer's energy use to benefit the system.

3.9.1.1 Findings

[647] The Board accepts that NS Power is engaged in appropriate activities relating to the development of new rate designs. However, the Board believes that more can be done and encourages NS Power to do so. For example, while NS Power refers to the development of customer energy management systems as providing tools and information to customers to better understand their energy use and evaluate rate options that may be suitable for their usage patterns, there are not many rate options for many customers to choose from. The Board is also concerned that NS Power's outdated customer information system and the recent cyber attack have or will impede its progress in this area in the short term. The Board notes, for instance, that the TVP program was effectively suspended for the 2025/2026 winter season due to the company's inability to access data after the cyber incident.

[648] As Bonbright notes, the characteristics of a sound rate structure should include designs that are dynamically efficient in promoting innovation and responding economically to changing demand and supply patterns, discourage wasteful use of service and promote all justified types and amount of use. In the context of the energy transition, these characteristics of rate design should be a focus.

3.9.2 Residential and Small General Customer Charges

[649] In its last general rate application, NS Power proposed to increase customer charges for the domestic service and small general customer classes to align those charges with costs under its cost-of-service study. Other parties in the proceeding expressed some concerns about that proposal and, in the settlement agreement in that matter, customer charges for these classes were set at 75% of the amounts proposed. In the present proceeding, NS Power proposes to increase these customer charges in the same proportion as the increases in the smoothed non-fuel cost revenues for these customer classes, as set out in Figure 13-1 in its application:

Figure 13-1 – Proposed Increases to Customer Charges

Customer Class	Current Rate ($)	Proposed Rate ($) 2026	Proposed Rate ($) 2027
Domestic Service	19.17	20.24	21.38
Small General	21.28	22.16	23.07

[Exhibit N-3, p. 81]

[650] In its response to NSEB IR-133, NS Power also calculated the customer charges that would result from a direct use of customer costs under its cost-of-service study. The results, which are reproduced below, also showed the offsetting impact on the proposed energy rates to maintain the required recovery of costs in the rates set for these customers:

Domestic Service Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge ($/month)	**$20.24**	**$29.32**	**$9.07**	**45%**
Energy Charge (cents/kWh)	**18.349**	**17.306**	**(1.043)**	**-6%**
Smoothed Rate				
Customer Charge ($/month)	**$20.24**	**$29.32**	**$9.07**	**45%**
Energy Charge (cents/kWh)	**18.454**	**17.411**	**(1.043)**	**-6%**
2027				
Standard Rate				
Customer Charge ($/month)	**$21.38**	**$30.25**	**$8.88**	**42%**
Energy Charge (cents/kWh)	**19.335**	**18.310**	**(1.025)**	**-5%**
Smoothed Rate				
Customer Charge ($/month)	**$21.38**	**$30.25**	**$8.88**	**42%**
Energy Charge (cents/kWh)	**19.216**	**18.191**	**(1.025)**	**-5%**

Small General Tariff				
	Capped Customer Charge	COSS-based Customer charge	Variance	Percent Variance
2026				
Standard Rate				
Customer Charge ($/month)	**$22.16**	**$31.98**	**$9.82**	**44%**
Energy Charge (First 200 kWh) (cents/kWh)	**18.918**	**17.840**	**(1.078)**	**-6%**
Energy Charge (Additional kWh) (cents/kWh)	**17.089**	**16.208**	**(0.881)**	**-5%**
Smoothed Rate				
Customer Charge ($/month)	**$22.16**	**$31.98**	**$9.82**	**44%**
Energy Charge (First 200 kWh) (cents/kWh)	**19.053**	**17.975**	**(1.078)**	**-6%**
Energy Charge (Additional kWh) (cents/kWh)	**17.224**	**16.343**	**(0.881)**	**-5%**
2027				
Standard Rate				
Customer Charge ($/month)	**$23.07**	**$33.28**	**$10.21**	**44%**
Energy Charge (First 200 kWh) (cents/kWh)	**20.100**	**18.984**	**(1.116)**	**-6%**
Energy Charge (Additional kWh) (cents/kWh)	**18.074**	**17.163**	**(0.911)**	**-5%**
Smoothed Rate				
Customer Charge ($/month)	**$23.07**	**$33.28**	**$10.21**	**44%**
Energy Charge (First 200 kWh) (cents/kWh)	**19.951**	**18.835**	**(1.116)**	**-6%**
Energy Charge (Additional kWh) (cents/kWh)	**17.925**	**17.014**	**(0.911)**	**-5%**

[Exhibit N-27, PDF pp. 550-551]

[651] As can be seen in the foregoing tables, keeping lower customer charges necessarily increases energy charges, and vice versa. Customers in these classes that use higher than average amounts of energy pay more when customer charges are lower and less when customer charges are higher. The opposite is true for customers who use less energy than the average customer in the rate class. The extent to which the energy rate is higher or lower also affects the cost effectiveness of energy efficiency and demand response programs for these customers. It may also affect the choice of alternatively designed rates.

3.9.2.1 Findings

[652] The Board accepts that there may be legitimate arguments for not setting customer charges for these classes directly from the cost-of-service study. However, given the potential impacts that the setting of customer and energy charges may have on intra-class cost shifting, efficiency and demand response, and the consideration of alternatively designed rates, there should be a principled basis for doing so. The extent of the variance should not be arbitrary. While increasing these charges based on the average increase in non-fuel revenues for these customers might be convenient, it is not clear to the Board that costs classified as customer-related under the cost-of-service study necessarily change at the same rate as other costs.

[653] The Board directs NS Power to consider this matter and address it in more detail in its next general rate application. The Board notes that the method for classifying distribution system costs to customers also affects this issue. Indeed, in the Ontario Energy Board cost allocation review staff discussion paper submitted as Exhibit N-63, it appears to be suggested that fixed monthly customer charges could conceivably be considered within a range of reasonableness bounded by a floor set using the basic

customer method and a ceiling using either the zero-intercept or minimum system methods (p. 14).

3.10 Miscellaneous Charges and Regulations

3.10.1 OATT

[654] NS Power's Open Access Transmission Tariff (OATT) includes terms, conditions and rates for Transmission Services and Ancillary Services. It also includes operating agreements under which service will be provided, and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power. The OATT was initially approved in 2005 and amended on June 10, 2016.

[655] In this application, NS Power updated OATT rates to reflect changes in revenue requirement, driven by changes in generation and transmission asset mix and costs, and changes in system usage since the last update in the 2023-2024 GRA.

[656] NS Power proposed amending the OATT methodology based on consultation in the 2024 Cost of Service proceeding. Those amendments include basing OATT rates on forecasted test year usage instead of historic usage, and basing transmission rates under schedules 7, 8 and 10 on transmission-related revenue requirement as determined in Cost-of-Service studies instead of on formulaic calculations. NS Power stated those proposed amendments will help eliminate transmission revenue requirements differences used for the OATT and bundled service rates.

[657] NS Power also proposed a modification to the determination of reactive power usage, applied in rate calculations under Schedule 2, from a single system peak

hour to a multi-hour peak based on the 97th percentile usage of Reactive Power from generation.

[658] The 2023-2024 GRA (M10431) Board Order included the following directives regarding the OATT and capacity-based ancillary services (CBAS):

- To explore options with Northern Power Coordinating Council (NPCC) about alternative treatment of interruptible loads and to file its analysis of cost implications in the next GRA;
- Explore, prior to the next GRA, alternative treatment of the -16 MW requirement in Automatic Generation Control and to demonstrate that it is not double charging transmission customers;
- Demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization for Wreck Cove is represented in its CBAS calculations; and
- Provide a more fulsome explanation, no later than in its next GRA, to justify its position to exclude combustion turbine (CT) units from its costing of 30-minute supplemental reserve for the CBAS calculations.

NS Power addressed those directives and incorporated certain changes based on its review of those issues.

[659] Ancillary Services are support services required to enable the transmission system to transmit energy while maintaining reliable operation of the system. They range from actions needed to enable and balance a transfer of electricity between buyer and seller, to services needed to maintain transmission system integrity and reliable operation at designed voltages and frequency.

[660] The OATT requires NS Power, as the Transmission Provider, to make all Ancillary Services available to all Transmission Customers, so it must be able to procure adequate generation resources to do so. Transmission Customers can purchase each of the Ancillary Services from the Transmission Provider, or they can self-supply the capacity-based ancillary services or purchase them from a third party.

[661] The capacity-based ancillary services include Regulation and Frequency Response Service, as well as Operating Reserves, which include 10-minute spinning reserve, 10-minute supplemental reserve, and 30-minute supplemental reserve. NPCC defines the requirement for Operating Reserves in the Maritimes Control Area. At all times, NS Power must have 32 MW of spare capacity available from units already online (spinning reserve), 136 MW of capacity (or load reduction) that can be made available within 10 minutes (supplemental reserve), and an additional 50 MW of capacity (or load reduction) that can be made available within 30-minutes (supplemental reserve).

[662] Regarding treatment of interruptible load, NS Power stated that LIIR interruptible load is not suitable for day-ahead reserve planning, but it does provide value when used in real time to manage through capacity scarcity events. Under the settlement agreement, it was agreed that the costing approach for 2026 and 2027 will utilize 50% of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis. This reduces the required 10-minute supplemental reserve of 136 MW by 35 MW, to 101 MW, for pricing purposes of that service. Accordingly, LIIR interruptible load equipped with Telemetry and Control will be included in managing real-time 10-minute reserve at all times, not just when it is not available from generation resources.

[663] On the issue of alternative cost treatment of the -16 MW requirement in regulation service, as its own Balancing Authority, NS Power must balance load and generation within the province, measured by the Area Control Error on the Nova Scotia-New Brunswick (NS-NB) tie-line. To maintain transmission security limits, Area Control Error on the NS-NB tie-line must be closely controlled. Area Control Error changes can affect the stability of the transmission network, so adequate regulation capability is needed to manage deviations in net load and variable generation to ensure system stability. NS Power's analysis of net load-variable generation deviations in the NS Balancing Area determined that it needs +/- 16 MW of regulation capability to adequately manage the system with the current level of variable generation and load behaviour.

[664] NS Power noted that when a dispatchable generator is operating at or near minimum generation limits, it bottoms out on its ability to provide Regulation Down (Reg Down) service (i.e., the -16 MW component). That generator's capacity would still be supplying customer energy needs, but it cannot offer Reg Down service because its output cannot be lowered any further. NS Power submits that capacity for Reg Down service must be set aside separately from capacity used to serve the energy needs of load customers. Since that set-aside capacity is incremental to the capacity allocated to serving energy, NS Power stated that its cost must be recovered through the prescribed costing methodology of the OATT. NS Power maintains that the current costing methodology adequately and fairly allocates capacity costs to the provision of Regulation Service and submits that there is no double-counting of capacity.

[665] Regarding NS Power's treatment of spinning reserve and 10-minute supplementary reserve utilization of Wreck Cove in its CBAS calculations, NS Power

determined that capping Wreck Cove at a 32 MW capacity contribution (the current requirement for Spinning Reserve) produces a 10-Minute Spinning Reserve weighted annual cost of $139.69/kW, which is immaterially different by 0.2% as compared to the $139.98/kW rate used in the 2023-2024 GRA. NS Power has capped the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service.

[666] The issue of including less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve was also reviewed by NS Power. It noted that the power system is experiencing a transformation from a system with large base-loaded, dispatchable generators to one with a large and growing penetration of variable renewable energy resources. With that understanding, NS Power conducted an analysis of historical day-ahead dispatch plans for the years 2021 to 2023 and determined that CTs were dispatched to fulfill approximately 35% of the 30-Minute Supplemental Reserve requirement each hour.

[667] Given this change, NS Power adjusted the cost allocation for 30-Minute Supplemental Reserve to account for the contribution that CTs make in the provision of 30-Minute reserve, as per its analysis, and implemented the adjustment in this GRA.

3.10.1.1 Findings

[668] As noted above, OATT rates have been updated to reflect changes in the generation and transmission asset mix and costs, and changes in system usage since the last update in the 2023-2024 GRA. NS Power also amended the OATT methodology based on consultation in the 2024 Cost of Service proceeding.

[669] In addition, NS Power addressed the Board's hearing order directives from the 2023-2024 GRA (M10431) pertaining to the OATT and capacity-based ancillary services, and incorporated certain changes based on its review of those issues.

[670] The Board approves the OATT amendments as proposed by NS Power in this matter.

3.10.2 AMI Opt-Out Fee

[671] NS Power has requested Board approval to implement an opt-out fee for customers who have not agreed to the installation of an AMI smart meter for remote meter reading and billing purposes. Capital and operating costs associated with the AMI facilities are embedded in NS Power's revenue requirement and those costs are being recovered from all customers, including opt-out customers.

[672] NS Power's proposed monthly opt-out charges are provided in Table 1.

Table 1 – Proposed Schedule of AMI Opt-out Fee Monthly Charges for 2026 and 2027

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Bi-monthly (6 times per year)	Semi-annually (twice per year)	$3.81 per month	$4.47 per month

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Monthly (12 times per year)	No change (12 times per year)	$22.89 per month	$26.79 per month

[Exhibit N-8, Appendix 13A, pp. 3-4]

[673] To reduce monthly charges for opt-out customers, NS Power proposes to conduct semi-annual meter readings for customers whose meters are currently read bi-monthly (i.e., Domestic and Small General classes), and to continue monthly readings for

customer classes that include a monthly demand charge (i.e., General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff). NS Power estimated that the reduced frequency of manual meter readings will lower the total required meter reading hours by 64% and result in a total estimated cost savings of $1.2 million over 2026 and 2027.

[674] When addressing the option of customer-submitted meter readings, NS Power dismissed that option as “not a reasonable proxy for NS Power meter reads”. It suggested it would be challenging for customers to provide accurate readings and that it could result in intentional misreporting:

> AMI meters are digital; they cycle through various data points, which make it challenging to accurately capture consumption readings and increase the likelihood of unintentional errors in customer-submitted readings. In 2024, approximately 177 customer accounts submitted a post card or photo meter read; this represents less than 1 percent of the 18,140 customers that have opted out of AMI meters. Customer-submitted meter readings can also result in intentional misreporting, particularly in the absence of established regular and systematic utility-led verification processes. While Regulation 5.1 allows for customer-submitted readings, NS Power still needs to receive, verify, and process these readings, along with handling disputes and correcting errors.
>
> [Exhibit N-8 Appendix 13A, p. 8]

[675] In response to Board IR-148, NS Power stated that in 2024, there were 16 postcard meter submissions and 161 photo meter submissions; however, it does not track if those submissions provided incorrect readings. When asked if instructional material is, or can be, available to assist customers to correctly record their AMI digital meter readings, NS Power stated:

> Instructional material is currently available on the Company’s website (FAQ| Nova Scotia Power). NS Power plans to update its current self-report online forms which augment the existing content. This is part of the MyAccount restoration work being conducted in response to the cybersecurity incident and is expected to be completed in 2026.
>
> [Exhibit N-27, IR-148, p. 2]

[676] Board IR-148 also asked NS Power if it had the ability to detect billing anomalies that might indicate incorrect meter readings (whether intentional or not). NS

Power said it has the ability to identify customer bills that exceed a pre-defined dollar-value threshold set for any particular rate code. This issue was further canvassed during the hearing:

> **Q.** I think the last question I asked was -- it was in response to your response, which I understood to indicate that there wasn't a specific threshold that was set once for the entire rate code, that it was more, to use your words, nimble than that. And so I asked whether each individual customer account had a threshold set for it.
>
> **A.** (Williams) Yes. I don't believe it's a specific threshold that's established and held static, if you will. My understanding is that it's -- the system will recognize when there's higher energy usage than would be expected or typical, and I believe that that occurs through the "My Energy Insights" program.
>
> **Q.** So this response refers to a pre-defined dollar value threshold. What does that mean?
>
> **A.** (Williams) So again, my understanding is that it's pre-defined through the system in terms of the historical usage, that it wouldn't be the same dollar value for every customer.
>
> [Transcript, January 12, 2026, pp. 968-969]

[677] On page 9 of Appendix 13A, NS Power stated that "Opt-out meter reading is based on the forecast incremental cost to serve opt-out customers, and informed by the company's actual experience with opt-out costs". On page 6 of that Appendix, NS Power stated that it "has explored all reasonable options to minimize or eliminate the proposed fee".

[678] Exhibit N-8, Appendix 13C shows that in 2024, there were 18,140 opt-out customers. In that year, NS Power received 650 inbound calls from opt-out customers which resulted in Customer Care expenses of $10,000. The opt-out development chart presented in Exhibit N-4, PR-02 Attachment 1 shows an estimated 18,819 opt-out customers for 2025, Customer Care Calls totalling 13,333, and Customer Care cost for opt-out only as $144,863. When questioned during the hearing about this large variance, NS Power stated that the 2025 projection was based on 0.71 calls annually per opt-out customer since NS Power assumed there would be a much greater influx of calls after

the actual meter reading frequency for domestic customers changes from six readings per year to two readings per year (i.e., from bi-monthly to semi-annual). By comparison, the actual number of calls per opt-out customer in 2024 was only 0.036, which is 20 times lower than the estimate NS Power assumed for 2025.

[679] Also, during the hearing, NS Power was questioned whether opt-out meter reading activity was separated from other manual reading activity. NS Power stated that it hired 100 meter readers to manually read meters when communication between AMI meters and its billing system was disrupted by the cyber incident. It further confirmed that those contracted meter readers were reading opt-out meters:

> **Q.** Are contracted meter readers also reading opt-out meters?
>
> **A.** (Williams) Yes.
>
> **Q.** They are?
>
> **A.** (Williams) Yes.
>
> …
>
> **Q.** And the meter readers are reading opt-out meters. Are they doing the other general work as well? Were they hired on to do the cyber work?
>
> So because presumably you had reader meters just to do opt-out meters. Are they also reading the cyber-related meters -- cyber reach?
>
> **A.** (Williams) So we would have a limited number of meter readers on staff for those opt-out meters. I can't say definitively at certain points of time whether there's delineation being drawn definitively on -- to that level of detail…
>
> [Transcript, January 9, 2026, pp.898-899]

3.10.2.1 Findings

[680] The Board has several concerns with NS Power's request to implement AMI opt-out fees at this time. Based on the responses provided during the hearing, it appears that meter reader costs associated with opt-out meters and those associated with cyber related manual meter readings are insufficiently delineated to accurately assess opt-out

fees. Also, despite NS Power's statement that opt-out costs are informed by actual experience, development of those costs appears to be based on certain questionable forecast assumptions. For example, projecting a 20-fold increase in customer care costs and opt-out calls after fees are implemented raises further concerns.

[681] Regarding potential self-reporting options for opt-out customers, NS Power has dismissed that option by suggesting it is too challenging to accurately read digital meters or that customers might intentionally (or unintentionally) submit incorrect readings. Those statements were made despite acknowledging that numerous photo meter readings have been accepted by NS Power and meter reading instructional material is currently available on the company's website.

[682] Regarding the possibility of intentionally or unintentionally submitting incorrect readings, the Board notes that NS Power currently has set certain bill thresholds against which individual bills are reviewed for anomalies, such as high bills. NS Power also stated it intends to explore additional criteria to identify bill exceptions through its Customer Information System modernization initiative. The Board questions whether NS Power has given sufficient consideration to establishing bill thresholds which could flag photo or postcard reading submissions that may be incorrect. Perhaps advancements in technology, such as artificial intelligence, could alleviate that concern.

[683] NS Power appears reluctant to consider providing opt-out customers with options such as self-reporting which could facilitate maintaining bi-monthly readings, or perhaps might require only a single manual reading for verification purposes. NS Power's meter reading regulation 5.1 states that the company may adopt a postcard meter reading system in rural areas and may consider postcard meter readings to be actual meter

readings. That regulation currently states that “Notwithstanding the foregoing, an actual reading must be taken by the Company at least once within a twelve-month period for meters which are read bi-monthly and once within a six-month period for meters which are read monthly”. NS Power has not provided any reasonable justification why a similar option could not be available to opt-out customers.

[684] The Board is not persuaded that implementing semi-annual or monthly manual meter readings and applying opt-out fees is the only option that should be made available to customers. Based on the concerns noted above, the Board denies NS Power’s request to impose opt-out fees or to amend related regulations at this time. NS Power is directed to address this in a compliance filing.

3.10.3 Revised Fees and Regulations

[685] In its application, NS Power proposed revisions to its Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees. Subject to the Board’s findings above relating to the AMI opt-out fee, the Board approves these revisions.

4.0 OTHER ISSUES

4.1 Demand Side Management Cost Recovery Rider

[686] In this GRA, NS Power proposed changes to the methodology for calculating the Balance Adjustment (BA) but did not propose changes to the Demand Side Management (DSM) rider amounts for 2026 or 2027. NS Power filed its DCRR application for recovery of the 2026 DSM expenses, using the current DCRR framework, on October 22, 2025 (M12521). The Board’s Interim Order of December 22, 2025,

approved continuation of the 2025 DCRR charges commencing January 1, 2026, until further order of the Board in that matter, or as part of NS Power's ongoing general rate application. The 2026 DSM expenditure level was set at $63.75 million by legislation and in this GRA, NS Power assumed the same expenditure level for 2027. Similarly, it assumed continuation of the DCRR amounts for 2026 or 2027.

[687] In proposing the change to the BA methodology, NS Power's response to Board IR-143 referenced the flexibility for E1 to re-allocate DSM expenditures between rate classes within a DSM term, and recent legislative changes which prescribe five-year DSM terms beginning with the 2027-2031 DSM Plan. It noted that the end-of-term true-up under the current framework might result in large variances to be collected or refunded through the DCRR. The new proposal would extend the recovery or refund period for end-of-term variances, which is expected to reduce the volatility in rate impacts of DSM expenditure reallocations and better reflect the multi-year nature of DSM planning and spending.

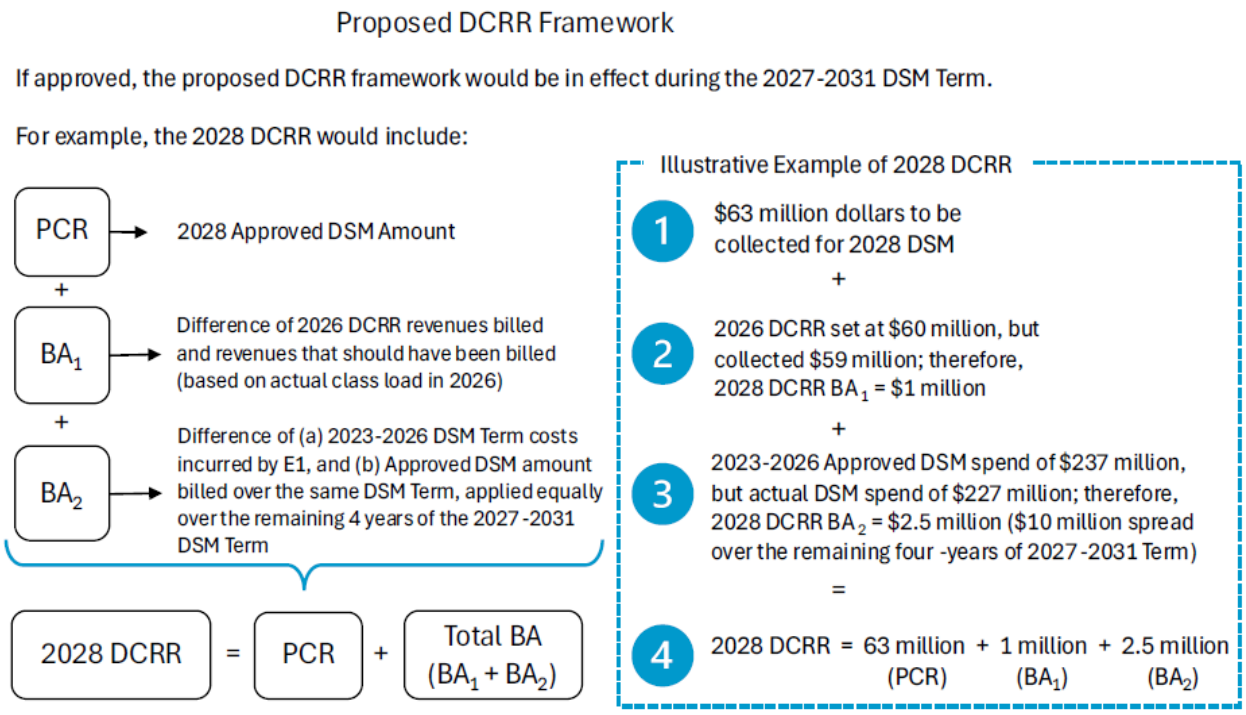
[688] The proposed DCRR framework adds a BA_2 component to the BA to reconcile, by rate class, the differences between E1's approved and actual DSM expenditures following the completion of the prior DSM Plan term. Under the current DCRR framework, those variances would be trued up and recovered over one or two years. The proposed BA_2 allocates those variances evenly over a four-year recovery period, beginning in year two of the following term, reducing the volatility in rates driven by E1 expenditure decisions.

[689] In addition, the proposed framework will allocate 100% of the DSM costs to classes in accordance with DSM program spending. This is intended to align with feedback and the recent COSS. In Matter M12521, NS Power stated:

> NS Power is proposing to amend the allocation of the Demand Side Management (DSM) Rider. Currently, the DSM Rider is allocated as 75 percent to the cost of programs undertaken for the rate class, with the remaining 25 percent allocated to the system benefit of the programs. Based on stakeholder feedback, NS Power is proposing to remove the allocation to system benefit, so that 100 percent of DSM Costs will be allocated to classes in accordance with program spending. This will more accurately align cost responsibility with the direct beneficiaries of DSM program spending. The 25 percent allocation to system benefit that was used previously was an arbitrary number, as discussed in NS Power's response to CA DR-87, which includes an analysis demonstrating that very little system benefit is provided by the DSM Rider. The change of allocation to remove system benefit, and allocation of the DSM Rider 100 percent to program costs, will also serve to place NS Power in better alignment with other jurisdictions and allow for simplification of the COS treatment of these costs. This is also described in more detail within the Elenchus Report.
>
> [M12521, Exhibit N-1, p. 5]

[690] The proposed BA methodology will include the annual volume variance adjustment (BA_1), calculated by class, for the difference between the actual revenues billed and the forecast revenues for the previous calendar year. That component will be applied on a two-year lag. An End of Approved DSM Term Adjustment (BA_2) will also be included, which trues up the differences by class between the approved and actual spending over the most recent DSM term (period governing the supply agreement). That amount will be calculated in the first year of the next DSM term and will be applied over the four following years of the DSM term. The BA will reflect the annual volume variance adjustment each year and the DSM term adjustment after the conclusion of each term.

[691] In its response to Board IR-143, NS Power provided a graphic of the proposed framework:



[Exhibit N-27, NSEB IR-143, p. 2]

[692] In the example, BA_1 reconciles volume-based variances and BA_2 adds a DSM expenditures-based reconciliation mechanism. Variances following the end of the 2023-2026 DSM term would be calculated in 2028 and allocated across the remaining four-years of the 2027-2031 DSM term (i.e. 2028, 2029, 2030, and 2031).

4.1.1 Findings

[693] The Board's Interim Order in Matter M12521 approved continuation of the 2025 DCRR charges commencing January 1, 2026, until further order of the Board in that matter, or as part of NS Power's GRA. In this current matter, NS Power is not proposing changes to the DSM rider amounts for 2026 or 2027, but it is proposing changes to how the Balance Adjustment (BA) is calculated. Updated values for the rider amounts in 2026 will be approved in a final order in Matter M12521. Rider amounts for 2027 will be determined in a subsequent DCRR annual application.

[694] The Board notes that the proposed DCRR tariff amendments are intended to address potential end-of-term variances, as well as variance associated with E1's flexibility to re-allocate DSM expenditures between rate classes within a DSM term. Since those amendments are expected to improve the DSM cost recovery process, the Board approves the amended DCRR tariff.

4.2 Storm Cost Recovery Rider

[695] During the 2023-2024 GRA process, participants raised a concern about the asymmetrical nature of the Storm Cost Recovery Rider (SCRR). The current SCRR allows for NS Power to apply to recover Level 3 and 4 storm costs it incurs above those amounts included in the approved revenue requirement. However, it does not provide a mechanism by which funds could be returned to customers if the forecast amounts included in revenue requirement were not fully spent.

[696] In this application, NS Power is requesting approval to continue the SCRR as a pilot during 2026 and 2027. It is also asking that the SCRR be in place on a symmetrical basis, which would allow it to recover Level 3 and 4 storm OM&G restoration costs above those included in revenue requirement, and for any underspend of such costs to be returned to customers in each year.

[697] The key elements of the proposed SCRR are the same as what was approved in the 2023-2024 GRA, but with the added symmetrical component. It is worthy to note that storm costs eligible to be included in the Storm Cost Recovery Rider in any given year cannot exceed 2% of that year's forecast retail revenues. Eligible storm costs in excess of the 2% cap will be deferred to the subsequent year's SCRR.

[698] A new term proposed to be included in the amended SCRR states:

> However, if the actual Level 3 and Level 4 storm costs are below the amount of Level 3 and Level 4 storm costs included in NS Power's revenue requirement as approved by the NSEB, the Company will track any underspend in a SCRR Customer Account where it will be accumulated until a threshold amount of $2.5 million is reached or a balance has been held for three consecutive years, upon which time NS Power will make an application to return the underspend amount to customers.
>
> [Exhibit N-4, PR-01, Attachment 01V, p.1]

[699] The 2026 and 2027 values for the SCRR rider are zero but NS Power's forecast expenditures for OM&G storm restoration costs in 2026 and 2027 are:

Figure 13-2 – Storm Restoration OM&G Costs (Levels 1-4)

	Level 1 & 2 ($ million)	Level 3 & 4 ($ million)
2026	9.6	10.1
2027	9.8	10.3

[Exhibit N-3, p. 85]

[700] Level 3 and 4 forecasts are similar to the previous three years, but Level 1 and 2 forecasts are more than 30% above the amounts in each of the previous three years.

4.2.1 Findings

[701] As noted above, the 2026 and 2027 values for the SCRR rider are zero. The proposed amendments are expected to correct the unbalanced asymmetrical nature of the current version of the rider. The amendments should also minimize administrative burden that could result from requiring annual applications to refund small amounts of underspent funds. Recognizing these enhancements, the Board approves the proposed version of the SCRR to continue as a pilot during 2026 and 2027.

4.3 Climate Change Adaptation Plan

[702] The NSUARB, in its decision in NS Power's last general rate application, directed the utility to develop and file a climate change adaptation plan in consultation with interested parties:

> [339] The Board also notes that in its response to Board IR-171 [Exhibit N-69], NS Power identified a number of steps it is taking to address the challenge of a changing climate, as well as to meet increasing expectations from customers to mitigate risks from severe weather events. The Board is aware that utilities in other jurisdictions have developed formal climate change adaptation plans. For example, Hydro-Québec recently released a Climate Change Adaptation Plan for 2022-2024. Additionally, the Board understands that organizations like Electricity Canada and the Electric Power Research Institute have developed guidance documents for utilities to develop such plans and climate change adaptation strategies.
>
> [340] It is not clear to the Board whether the items identified by NS Power in its response to NSUARB IR-171 are part of a formalized Climate Change Adaptation Plan adopted by the Company. The Board considers that the implementation of such a plan, through a consultative process, may be useful in demonstrating the prudency of storm restoration costs in Storm Rider cost recovery applications, would engender confidence in such a rider if NS Power seeks to implement one after the period covered by the GRA Settlement Agreement, and would enhance NS Power's capital expenditure processes and integrated resource planning. As such, NS Power is directed to engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025. As with the COSS and Line Loss Study discussed later in this decision, the Board approves the deferral of the costs of developing this plan for recovery through rates after NS Power's next general rate application.
>
> [2023 NSUARB 12]

[703] NS Power filed a Climate Change Adaptation Plan and Wildfire Mitigation Plan in this proceeding [Exhibit N-5, Appendix 3B and Appendix 3C]. NS Power said it did have a climate adaptation plan before its last general rate application but noted the directive required a consultative process to develop a formal plan. It said the consultation process primarily relied on engagement with the Climate Adaptation Leadership Program and a technical conference with intervenors held before formally filing the plan as part of this general rate application.

[704] The essence of NS Power's Climate Change Adaptation Plan involves the collection and analysis of climate data and feeding this into its existing asset management system. While the plan references the identification of climate related vulnerabilities for

operational assets, it does not set out much detail about these vulnerabilities, potential mitigation measures to address them or the timelines involved. NS Power addressed this at the hearing:

> **Q.** So why doesn't this plan sort of identify what this valuable information is that you've gathered about the vulnerabilities and identify the potential mitigation measures and the timelines for the Board and interested parties? It all seems to be under the hood, as it were, in the asset management system. Why isn't it included transparently in the plan?
>
> **A.** (MacIntosh) So these factors evolve over time. The company does deploy systems asset management mechanism system, which includes the input of climate risks in our risk profiles, as well as the Climate Adaptation Management System which house those. But I appreciate your point that there are, I'll say, thousands of lines of associated data that is included in our climate modelling that's assigned to these assets. So we try to provide a sample of that inside this Climate Adaptation Plan, which is really trying to outline the methodology Nova Scotia Power used to incorporate these climate factors into our plan processes. But appreciate the point again that there's much more data that's associated with this and how those are assigned to our specific asset classes.
>
> [Transcript, January 12, 2026, pp. 1030-1031]

[705] Hydro-Québec's Climate Change Adaptation Plan (2022-2024), entered in this proceeding as Exhibit N-62, was also the subject of questions presented to NS Power's witnesses at the hearing. As outlined in the Hydro-Québec plan, that utility developed its plan in two phases. The first phase consisted of compiling a list of climate change risks that could affect assets and the second phase focused on establishing action areas, identifying potential adaptation measures and determining what actions to take to mitigate risks. NS Power appeared to agree that while it undertook a process comparable to the first phase of the development of the Hydro-Québec plan, the NS Power plan does not present information consistent with the second phase. NS Power maintains that its plan presents the method it has been and will continue to use to identify and undertake climate adaptation measures.

[706] Likewise, the Hydro-Québec plan included "fact sheets" that describe climate related impacts on utility activities or assets, provide further information for

context, list the actions to address the particular issue and the potential adaptation measures, and identify any challenges to overcoming mitigating those risks. NS Power's plan has no similar information. However, NS Power said this information is in its climate adaptation management system, a program database, and could be provided.

4.3.1 Findings

[707] The fact that NS Power compiles and analyzes climate data and uses this information in its asset management systems is positive. However, NS Power's Climate Change Adaptation Plan is more of a process than a plan per se. It also focuses specifically on assets and is less directly connected to its other resources and operations.

[708] As noted above, part of the NSUARB's intention in directing the development of a climate change adaptation plan was to assist in demonstrating the prudency of storm restoration costs, engender confidence in NS Power's storm cost recovery rider and enhance its capital expenditure and integrated resource planning processes. The Board is concerned that what NS Power has presented has not and will not fully achieve these objectives.

[709] NS Power's asset management processes were recently reviewed (2024 NSUARB 59) and there were only limited concerns raised about them, which the utility has taken steps to address. While these processes may very well be reasonable and adequate, they are not very transparent.

[710] Further, it is not apparent to the Board that regular intervenors in proceedings involving NS Power were included in the development of NS Power's plan. What was described by NS Power in the evidence in this proceeding was a more modest level of consultation with those parties than the Board would have expected.

[711] The Board finds that NS Power's Climate Change Adaptation Plan would be enhanced if, like the Hydro-Québec plan, it included information to more clearly and transparently describe and provide context around potential or anticipated climate related impacts on utility resources, activities and assets; actions to address issues identified; potential and likely adaptation measures; and any challenges to mitigating risks. NS Power is directed to file a revised Climate Change Adaptation Plan with the Board adding these elements no later than October 1, 2026.

4.4 Lingan Unit 2 and Trenton Unit 5

[712] In its general rate application, NS Power assumed sustaining capital expenses of $20,829,182 at Lingan 2 during the 2026-2027 test period, including $18,433,591 in 2026 and $2,395,591 in 2027 (Bates White IR-11, Attachment 1). At the hearing, NS Power stated that, based on the latest information, the forecast sustaining capital costs for Lingan 2 are now projected to be deferred from 2026 to 2027.

[713] Moreover, it forecasts OM&G costs of $8.9 million at Trenton Unit 5 and Lingan Unit 2 during the test period due to a change in the retirement assumptions for these coal units and increased hours of operation [Exhibit N-6, Appendix 7C, PDF p. 63]. The OM&G costs include increased labour, contracts and materials resulting from the need for these units to remain available for dispatch until at least 2027 for Lingan 2 and 2029 for Trenton 5 [Exhibit N-23, GT IR-26]. The increased OM&G labour costs for these two coal units represent an increase of 49 FTEs in 2026 compared to 2024CR [Exhibit N-27, NSEB IR-42, pp. 2-3].

[714] In its evidence, Bates White noted that the forecast sustaining capital costs at Lingan 2 marks a departure from recent experience at the coal unit and represents a relatively "substantial cost" for the modest amount of energy the unit is forecast to provide

in the test period. It recommended that the proposed large increase in sustaining capital costs for Lingan 2 “be supplemented with additional narrative support” by the company.

[715] In response to questions from Board Counsel and the Board, NS Power stated that until now the company has managed the risks of operating Lingan 2 through asset management techniques, including “operational restrictions and enhanced monitoring”. It said it has delayed major refurbishment work but now a complete turbine and generator refurbishment is needed to maintain the safe operation of the coal unit. It also noted that sustaining capital for Lingan 2 has been very low compared to other units. Failure to conduct refurbishment work could result in significant consequential damages.

[716] Jonathan MacIntosh, Director of Enterprise Asset Management for NS Power, testified that any capital projects for Lingan 2 will be “brought before this Board for approval in addition to its operating cost, so approving this GRA does not approve the Lingan Unit 2 capital”. However, he acknowledged in questioning by the Board that those costs are embedded in the proposed rates (Transcript, January 9, 2026, p. 694).

[717] NS Power stated that these coal units have been retained to serve customer load and provide system capacity, as required by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) requirements. It explained the changes to the coal plant retirement timelines:

> (a) The retirement assumption for Lingan 2 changed in Q2 2024 following the completion of the 2024 Load Forecast (which had an increase of 108 MW in the forecast firm peak for 2024) and concurrent with the development of the 2024 10-Year System Outlook. The resource and capacity assessment developed for the 2024 10-Year System Outlook identified that due to the change in the load forecast it was necessary to extend the use of Lingan 2 until replacement firm capacity procured by IESO-NS came online. An updated retirement date of 2027 for Lingan 2 was provided in the 2024 10-Year System Outlook, which was submitted to the Board on June 27, 2024. The change in the forecast retirement date for Trenton 5 to 2027 was a finding of the 2023 Evergreen IRP. It was first reflected in the 2023 10-Year System Outlook, and is shown in subsequent reports. The decommissioning timeline for Trenton 5 was further updated in the 2024 Decarbonization Deferral Account (DDA) - 2024 Annual Report. The update in the 2024 DDA report reflects the need to maintain units available until reliable

> operation of replacement generation has been established and that decommissioning activities are not expected to begin until after 2029.
>
> [Exhibit N-23, GT IR-26, pp. 1-2].

[718] In a recent application for Lingan 2 sustaining capital costs, NS Power noted that IESO Nova Scotia is responsible for the procurement of fast-acting replacement generation, but "given the lead times seen across the industry for new combustion turbines, it is increasingly unlikely that the NSIESO's procurement process will allow new fast-acting generation units to be online by Winter 2027-28" [Exhibit N-60, p. 2]. Accordingly, it is keeping Lingan 2 in cold reserve until the reliable operation of replacement generation is available. NS Power confirmed that it has expressed its concerns to IESO Nova Scotia about the latter's procurement of fast-acting generation and its implications, including in relation to Lingan 2.

[719] In its closing submissions, the Department of Energy submitted that the Board assess the utility's need for additional investment in Lingan 2 and to deny NS Power's request for sustaining capital costs.

4.4.1 Findings

[720] NS Power's firm capacity requirements in advance of 2030 continue to be the subject of review in several matters considered by the Board, including the Evergreen IRP Action Plan and Roadmap Update, the 10-Year System Outlook Report, the Load Forecast, the annual ACE Plan and The Path to 2030. The approval of sustaining capital costs for Lingan 2 is not an issue under review in this matter. While the Board is mindful of the concerns expressed by the Department of Energy and Bates White, NS Power's request for sustaining capital costs will be considered in another proceeding. The 2026

ACE Plan matter (M12619) noted that the application will be filed as a subsequent submittal.

[721] OM&G costs of $8.9 million are forecast at Trenton Unit 5 and Lingan Unit 2 during the test period. NS Power has demonstrated in various proceedings that Lingan 2 and Trenton 5 are required to maintain adequate capacity to serve customers, including keeping a planning reserve margin required by NERC and NPCC. These detailed proceedings have included the Evergreen IRP Action Plan and Roadmap Update, as well as the 10-Year System Outlook Report and the Load Forecast which are updated annually.

[722] The Board finds that the proposed OM&G costs for Lingan 2 and Trenton 5 are required to provide customers with safe and reliable service. They are also required to support compliance with important NERC and NPCC requirements. Accordingly, the Board approves the forecast OM&G costs for these units in the test period.

4.5 Rate Setting – Alternative Form of Regulation

[723] In its closing submissions the Nova Scotia Liberal Caucus urged the Board to exercise its statutory authority to move Nova Scotia toward a five-year rate plan that delivers stability, predictability, and fairness for ratepayers. Although the Liberal Caucus specifically referenced the Board's ability to approve multiyear rate applications under s.64A(2B) of the *Public Utilities Act* in its opening statement, more recent legislation provides more flexibility.

[724] The *Public Utilities Act* was amended in 2024 to allow the Energy Board to approve an application for a rate, toll or charge that is based on a method or technique the Energy Board considers appropriate, including an “alternative form of regulation” (s.

64(3)). This is consistent with language in the *Energy and Regulatory Boards Act* (s. 6(1)), which also provides a definition of “alternative form of regulation”:

> **Interpretation**
> **2** In this Act, unless the context otherwise requires,
>
> “alternative form of regulation” means a method of establishing just and reasonable rates, tolls, charges and tariffs by performance-based regulation, including earnings sharing, price caps, price indexing formulas, ranges of authorized rates of return and the increase, reduction or suspension of regulatory requirements, without regard to methods based strictly upon cost of service, rate base and rate of return;

[725] The possibility of implementing an alternative form of regulation was canvassed at the hearing and NS Power agreed that it was worthy of discussion. NS Power revisited this in its closing submissions:

> NS Power agrees that multi-year and performance-based rate plans warrant consideration. In theory, these plans could assist with providing for more predictable rate increases and a better understanding for customers, but the practical reality of implementing such plans is a much more complicated endeavor where an improved regulatory regime is not a certainty. Consideration of such plans must include how they may work and may improve on the current regulatory regime, taking into account the vertically integrated nature of NS Power and the work needed to meet Nova Scotia’s 2030 decarbonization goals. Included in these considerations would also be the establishment of the IESO-NS and the extent to which it will alter (1) existing regulatory responsibilities, such as RES and emissions compliance, as well as development, implementation, and oversight of wholesale and renewable to retail market tariffs, and (2) existing regulatory mechanisms, such as the FAM. NS Power would welcome the opportunity to continue such discussions with the Board and regulatory stakeholders to help the Board determine whether more detailed consideration would be appropriate.
>
> [NS Power Closing Submissions, p. 54]

4.5.1 Findings

[726] While the Board appreciates the complexity and challenges, a transition to performance-based rates should be explored. Key goals in such a transition would be the development of more predictable rate setting processes, the reduction of regulatory burden and the better alignment of utility incentives and customer interests. The Board will further consider how this may be moved forward.

4.6 Implementation of New Rates (Cyber Incident Impact)

[727] At the hearing, NS Power said that it now has communication with roughly 400,000 of its customer meters and has targeted the end of March to have all meters (approximately 555,000) communicating. It noted, however, that it was going to take time to get data from new meter reads and input that data into bills.

[728] NS Power explained that when a rate increase is implemented, it prorates the application of the new rates based upon the amount of time in the billing period that they were in effect. It also agreed that there was a potential that a longer period of time between actual meter readings might exist because of the cyber attack and that higher usage in a colder period could be charged at a higher than approved rate for that period of time given the impact of prorating rate changes:

> **THE CHAIR**: Isn't the potential now, though, right now, that there is customers who have gone on for a longer period of time between actual reads than would have been the case with prior rate increases?
>
> **MR. WILLIAMS**: There is — I do believe there is that potential, but I think it's certainly much more reduced than it would have been two or three months ago for sure.
>
> **THE CHAIR**: Okay. But still some customers who have larger than you would want periods where you're in between actual reads, you might be proportionately estimating for purposes of rate changes across potential seasons in terms of use?
>
> **MR. WILLIAMS**: I don't know that would be estimating across potential seasons at this point, but I think there is the potential there that it's longer than it would have been in some instances. But I would note that, I mean, prior to AMI technology we would have been in a very similar situation. We would have meter readers out there more regularly, and more meter readers on staff. But the issue is not a new one, in terms of having to estimate — the potential to have to estimate a bill despite the fact that there's been a rate increase.
>
> **THE CHAIR**: Well, it's colder now. So if a customer is using more electricity now, and we don't get a decision now and effective rates don't come in [‘till] March, April, whenever, part of the period is going to be an early colder period where it should be a lower rate, and part would be a higher rate but would be warmer when they're, perhaps, using less electricity. But your response is to prorate that across all of them, which would in effect have the customer really paying a little bit higher than they would otherwise. Correct?

> **MR. WILLIAMS**: Yes, sir, I agree. I mean, that is a reality in -- anytime there has been an increase in the past. And I'm going to keep going back, I suppose, to the fact that we've got 400,000 communicating at this point in time, and we do believe we're on track for March.
>
> [Transcript, January 9, 2026, pp. 788-790]

[729] NS Power also stated that when it is able to read data from the meters, it can recover stored data about historical use in the range of 60 to 90 days. However, the data is only stored for that finite period and does not include some information, such as interval usage (e.g., 15-minute interval usage).

4.6.1 Findings

[730] The Board is concerned that customers who have higher usage during the recent colder period of the year might end up paying more than the approved current rate for the electricity they are currently using because of the impact of prorating. This concern is exacerbated in cases where the period of time between actual meter reads has been prolonged because of the cyber attack.

[731] The Board understands that before the implementation of AMI meters, the implementation of a new rate in the middle of a billing cycle might mean that the bill for that period would need to be prorated. However, it is not clear to the Board why any bill rate change needs to be prorated if an AMI meter is used. As the Board understands it, an AMI meter would be able to precisely determine the amount of energy used before a new rate came into effect and after the new rate came into effect. In such circumstances, the Board would expect the approved rates at the time the energy is consumed would be used.

[732] Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time

that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used.

5.0 SUMMARY OF MAJOR FINDINGS AND DIRECTIVES

[733] The Board approves most components of the settlement agreement, subject to its findings below that amend the application. The following are approved:

- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes remains at 40.0%;

- The establishment of the securitization deferral to defer depreciation expenses and financing costs related to the coal plants and thermal-related assets within the scope of the Decarbonization Deferral Account, but only effective from the date the rate increases in this application are implemented;

- NS Power's proposed depreciation rates. The depreciation study is approved, including the exclusion of decommissioning costs for the Wreck Cove, Mersey and Tusket hydro plants; the inclusion of partial decommissioning costs for NS Power's other hydro plants; the net salvage rates for plant accounts both within and outside the settlement agreement; and the asset service lives presented in the application;

- The proposed cost-of-service methodology and cost allocation among the various customer classes, except that NS Power is directed to implement a load carrying capability adjustment to account for the demand component served by the minimum system used to classify distribution system costs and to address other cost-of-service issues as noted in this decision;

- The PHP Deferral account, based on the assumptions in the settlement agreement, to track any variances in revenue between that which would occur based on the assumptions in the cost-of-service study treating PHP as an Above-the-Line customer versus that which results from the eventual Board-approved tariff for PHP. NS Power estimated $18.2 million would accrue in the deferral if PHP remains as a Below-the-Line customer for the entirety of 2026 (Undertaking U-2), and there would also be a $5.7 million fuel balance captured under the FAM;

- The EIFEL deferral, allowing NS Power to defer incremental tax expense of about $7 million if an exemption is not enacted by the Government of Canada as it has announced;

- The inclusion of four Maritime Link transmission capital projects in rate base. The amount to be included in rate base is the net book value of these assets as of the date of the Board's Order;

- Continuing the Storm Cost Recovery Rider pilot in 2026 and 2027, but on a symmetrical basis, which allows for underspent Level 3 and 4 costs to be returned to customers;

- The change to the tariff language for the Demand Side Management Cost Recovery Rider;

- Revising the Open Access Transmission Tariff (OATT) rates to reflect changes in the generation and transmission asset mix and costs, changes in system usage since the last update in the 2023-2024 GRA, Board directives from the 2023-2024 GRA, and the revised methodology from the 2024 Cost of Service proceeding; and

- Other miscellaneous fee changes under the Schedule of Charges, such as for connection, reconnection, returned cheques, installation of recording equipment, contribution for three-phase service, load research charges, and pole attachment fees.

[734] However, the Board has made findings amending the general rate application and parts of the settlement agreement. It has made several adjustments in this decision to reduce NS Power’s proposed revenue requirement or adjust the allocation of costs among customer classes, including:

- A further reduction of $8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the $9 million outlined in the settlement agreement);
- A reduction in NS Power’s proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power’s proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of $1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;
- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and

- The denial of the proposed AMI opt-out fee.

[735] The Board has issued the following directives to NS Power:

- To provide a reconciliation showing the annual collection of interim and final net salvage in rates from 2009 onwards in its next depreciation study. This information is to be presented for actual interim salvage costs that have been incurred each year for each of the hydro assets where NS Power has proposed to cease collection of the final net salvage costs for the assets (para. [166]);

- To undertake a consultation process with interested parties about the decommissioning of hydro plants and to report on the results of the consultation every six months, starting no later than October 1, 2026 (para. [189]);

- To file an updated depreciation study with its next general rate application, with several directives to address a comparison of the ALG and ELG methodologies, including, but not limited to:

    - The interaction between depreciation expense and return on rate base;

    - The extent to which actual true aged data has been used;

    - A NS Power specific ALG vs. ELG cross-over point analysis;

    - Comparison to other peer utility data, particularly related to actual age data, the retirement patterns experienced by those utilities, recommended asset service lives, and a description of what forces of retirement those utilities have that are consistent with those of NS Power;

    - Identification of specific factors in Nova Scotia that differ from other peer utilities that would lead to a higher rate of retirement or greater forces of retirement;

    - The book accumulated depreciation reserve balance and calculated accumulated reserve balance under both the ALG and ELG procedure;

    - An evaluation of whether a change to the ALG procedure would violate the principles of gradualism and moderation, and whether a “phasing-in” of ALG would be appropriate; and

    - The proposed depreciation by asset account under both ELG and ALG procedures (paras. [233-234]);

- In its next depreciation study, to address Mr. Madsen’s recommendations related to asset service life accounts 354, 356, 367, and 390.10 (para. [254]);

- In its next depreciation study, provide at minimum the following information in support of both production Plant and mass property:

    - Detailed management notes for each account;

    - All analysis and studies performed by management for each asset to confirm the expected life;

    - All updated IRP documents;

    - A reconciliation of the lives proposed in the depreciation study to the lives proposed in the IRP; and

    - The peer analysis relied upon by the company in an Excel file (para. [255]);

- To address the additional cost-of-service concerns raised by Synapse in its application to the Board later in 2026, as required in the settlement agreement, in addition to the review of the minimum system v. basic customer method for allocating distribution system costs (para. [616]), as well as the analysis necessary to calculate the load carrying capability of its minimum system (para. [627]);

- To address the issues raised by Renewall in its closing submissions, if the utility brings forward any application relating to the OATT tariff or charges before responsibility for the transmission tariff is transferred to the Nova Scotia Independent Energy System Operator, including if NS Power files a general rate application (para. [642]);

- To address the setting of customer charges in its next general rate application (para. [653]);

- To file a revised Climate Change Adaptation Plan by October 1, 2026, outlining climate related impacts on the utility's resources, activities and assets; actions to address the issues identified; potential and likely adaptation measures; and any challenges to mitigating risks (para. [711]); and

- Unless NS Power is able to provide a compelling reason in its compliance filing demonstrating that it is not possible to use AMI data to avoid prorating bills to accommodate its proposed rate increase, the Board directs that the bills covering the time that the new rates come into effect be prepared on the basis that the energy consumed in the billing period is charged at the actual rate that was in effect when the energy was actually used (para. [732]).

6.0 COMPLIANCE FILING

[736] NS Power is to file a compliance filing based on the Board's findings in this decision. The compliance filing is to include, among other things:

- A further reduction of $8 million in Operating, Maintenance and General expenses in each of 2026 and 2027 (over and above the $9 million outlined in the settlement agreement);
- A reduction in NS Power's proposed executive compensation in both 2026 and 2027 to be consistent with the *Nova Scotia Power Incorporated Regulations*;
- The denial of NS Power's proposed deferral of general rate application OM&G costs (GRA deferral) for collection over the 2026-2027 period;
- A reduction of $1.8 million in fuel and purchased power costs in 2026 to reflect the present estimate for Maritime Link assessment costs, and to update the current 2027 estimate;
- To make the change to s. 3.2.8 of the FAM POA discussed in NSEB IR-33 and the other proposed amendments to the FAM POA and to the FAM Tariff;
- A peak load carrying capability adjustment of 0.4 kW per customer applied as a credit to the non-coincidental peak demand for determining the minimum system demand allocators for the distribution system costs (this change transfers the related costs from domestic, small general and unmetered customers to other rate classes) (Undertaking U-6); and
- The denial of the proposed AMI opt-out fee.

[737] NS Power is directed to file a compliance filing no later than two weeks after the date of this decision. Intervenors will have one week from the date that NS Power files its compliance filing to provide submissions to the Board. NS Power may file a reply within one week from the date the Intervenors file submissions.

[738] The Board approves NS Power's application, subject to the Board's findings and directives in this decision. The Board approves the rates and charges for 2026 effective the date of the Board's Order approving final rates in this matter and the rates and charges for 2027 effective January 1, 2027.

[739] Although the NSUARB approved rate increases in NS Power's last general rate application effective the date of its decision, this is not the normal practice. The normal practice, assuming an intention to implement rates on January 1st, is for NS Power to file its application early enough to allow for an appropriate process to occur and a decision to be made before January 1st. As noted earlier, NS Power did not file its application until late September 2025, practically ensuring that the matter would not be concluded before year-end.

[740] Failing that, the normal process is for rates to come into effect on the date of the Board's final Order in the matter. The exercise of the Board's discretion to do otherwise in NS Power's last general rate application was done in the unique circumstances arising at that time and it did not reflect the longstanding requirement for a compliance filing to determine the rates before they came into effect. Moreover, because new rates cannot be implemented until a final Order, if rates come into effect on the date of the Board's decision, then any bills issued after the Board's decision but before a final Order following a compliance filing would necessarily need to be retroactively adjusted. It is potentially confusing and frustrating for customers to see these sorts of adjustments on future bills. At the present time, this would only be aggravated because of recent and ongoing customer concerns about NS Power's estimation and billing practices in the wake of the cyber incident. In any event, the Board finds that allowing rates to come into effect on the date of a decision rather than when finalized in an Order should not become a customary practice.

[741] An Order will issue following the compliance filing.

DATED at Halifax, Nova Scotia, this 25th day of March 2026.

Stephen T. McGrath

Roland A. Deveau

Steven M. Murphy

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523, et al.
	:	
UGI Utilities, Inc. - Gas Division	:	

CAUSE-PA Statement No. 1

DIRECT TESTIMONY OF PATRICK M. CICERO
ON BEHALF OF
THE COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

April 13, 2026

As Corrected by Erratum

Further Corrected at June 2, 2026 Evidentiary Hearing

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PREPARED DIRECT TESTIMONY OF PATRICK M. CICERO

I. Introduction and Background

Q: Please state your name, occupation, and business address?

A: My name is Patrick M. Cicero. In my role as Of Counsel at the Pennsylvania Utility Law Project (PULP), I have a broad range of responsibilities to PULP and its clients. For example, when I am not representing any clients as an attorney, I provide analysis and testimony on utility matters for clients who are represented by members of the statewide legal aid network, including clients of PULP and other legal aid offices. PULP's business address is 118 Locust Street, Harrisburg, PA 17101.

Q: For whom are you testifying in this proceeding?

A: I am testifying on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

Q: What is the purpose of your testimony?

A: CAUSE-PA filed a complaint at this docket because it was concerned that the terms, conditions and rates for gas service proposed by UGI Utilities, Inc. – Gas Division (UGI or the Company) are neither just and reasonable nor affordable for UGI's low income customers. CAUSE-PA retained PULP to represent its interests. While other attorneys at PULP are representing the legal interests of CAUSE-PA, I have been asked to provide testimony about UGI's overall rate increase request, including its rate design, its existing tariff provisions, its proposed tariff changes, and the overall adequacy of its policies, procedures, and programs that are designed to ensure that UGI's low income customers are able to afford and maintain gas service at just and reasonable rates.

My testimony focuses on the overall unreasonableness of the Company's revenue request, its requested return on equity of 10.75%, its rate design proposals, including its proposal to increase the fixed customer charge for Residential customers from $16.25 per month to $23.00 per month, a proposed increase of 41.5%. In addition, I provide testimony about why the Company's tariffed Weather Normalization Adjustment (WNA) pilot is neither just nor reasonable and propose that it should not be renewed. I also provide recommendations about improvements that UGI can make to its customer service and universal service programs, including its allocation of universal service costs, as well as proposed changes to its tariff. Finally, I provide recommendations about reform to UGI's purchase of receivables program as well as other retail market reforms for residential customers served by retail natural gas suppliers given that residential customers have paid more than $56 million since January 2023, on net, to be served by the retail markets than they otherwise would have paid had all customers remained on default service.

Q: Have you provided testimony before the Pennsylvania Public Utility Commission in any prior cases?

A: Yes. I have served as a witness in several proceedings, including UGI's last rate case. A full list of proceedings in which I previously testified is included with my resume which is attached hereto as Appendix A. In addition to those proceedings in which I have provided testimony, I have significant prior experience before the Public Utility Commission (PUC or Commission), including in my role as the statutory representative of consumers while serving as Pennsylvania's Consumer Advocate leading the Pennsylvania Office of Consumer Advocate.

Q: What are your qualifications to provide testimony in this case?

A: I have more than 23 years of experience as an attorney, 20 years of which have been in the practice of legal aid or consumer advocacy. After 2 years clerking for a federal district court judge, I spent approximately 5 years as a staff attorney at MidPenn Legal Services in Harrisburg where I represented clients facing eviction, foreclosure, bankruptcy, and utility termination. After returning briefly to clerk at the federal district court, in early 2011, I began working at the Pennsylvania Utility Law Project – first as a staff attorney and ultimately as its Executive Director. In 2020, I was hired to lead the statewide legal aid network when I became the Executive Director of the Pennsylvania Legal Aid Network where I coordinated the work of the legal aid system in Pennsylvania that provides civil legal aid to Pennsylvania households. On December 13, 2021, I was appointed as the Commonwealth's Consumer Advocate leading the Office of Consumer Advocate (OCA) and was confirmed by the Pennsylvania Senate in June 2022. I served as the Consumer Advocate until January 31, 2025. In February 2025, I returned to work with PULP as Of Counsel.

Throughout my tenure in each of these roles, I have had the opportunity to see firsthand the extraordinary efforts that low income customers take to remain stably housed and connected to essential utility service. Day in and day out, low income – almost all of whom struggle to survive at income levels that are at or below 150% of the federal poverty level (FPL)[1] – have been forced to make difficult decisions about which bills to

[1] To put this in context, the 2026 federal poverty guidelines for a family of 4 require that a household not have more than $33,000 in annual income to be considered poor (100% FPL) which translates to $49,500 at 150% FPL. The complete guidelines are available here: Office of the Assistant Secretary for Planning

pay and which they must forgo. I have relevant experience helping low income consumers understand their utility bills and rates, why their charges are what they are, and what assistance, if any, is available to them to help pay their bills.

Furthermore, for more than 15 years at PULP and the OCA, I was instrumentally involved in the litigation of hundreds of cases before the PUC including rate cases, default service cases, universal service and energy conservation proceedings, Act 129 cases, and numerous other proceedings that require working knowledge and expertise in the issues about which I will be testifying in this proceeding. Simply put, throughout my career both in legal aid and as the Consumer Advocate, I developed specialized expertise in the needs of low income customers, the regulation of public utilities, the nuanced design and policy considerations of utility rates, and the ways that our regulatory system often fails the very consumers it is designed to protect by prioritizing the needs of public utilities over the needs of the utility's customers. This imbalance of power between utilities and consumers has resulted in utilities increasing rates at a significant pace. It has also resulted in utilities implementing more complex rates and rate designs. Taken together, this means that consumers, particularly low income consumers, are now more than ever struggling to understand the complexity of their utility bills, including how they are calculated each month, and what they can do to rein in the ever-increasing costs to allow them to afford and remain connected to essential utility service.

and Evaluation (ASPE), Poverty Guidelines, available at: https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines (Last visited March 26, 2026).

Q: Have you prepared Appendices and Exhibits to accompany your testimony?

A: Yes. I have prepared several appendices that are attached to my testimony. Appendix A is my resume, the last several pages of which contain a list of proceedings in which I have previously provided testimony. Appendix B are the interrogatory responses that I have relied on throughout my testimony. Appendix C contained various labeled exhibits there were prepared by me or under my supervision.

Q: Do you have any preliminary matters to address?

A: Yes. As noted, I am an attorney but my role in this case is as a witness. I am not serving as counsel to CAUSE-PA or any other client in this proceeding. Throughout my testimony, I refer to decisions by regulatory agencies and courts as well as reference statutes and regulations, however, these statements are not my legal opinion and should not be confused with the legal opinions of the attorneys representing CAUSE-PA. Any reference or citation is merely to provide context and support for my opinion about the public policy and rate design issues that I address and discuss in my testimony.

Q: Please summarize your conclusions and recommendations.

A: I recommend the Commission reject UGI's request to increase its rates. The evidence shows that UGI has sufficient revenue at current rates to provide safe and reliable service, cover its reasonably and prudently incurred expenses, and has a reasonable opportunity to earn a fair rate of return on its investments even at the end of the fully projected future test year. The evidence also shows that UGI's low income customers are significantly energy burdened at existing rates and any rate increase will exacerbate that burden.

I also recommend that the Commission deny any increase in UGI's fixed customer charge and recommend that the charge remains at its currently authorized level of $16.25 per month for residential customers. This recommendation is contingent on the Commission accepting my recommendation that UGI's WNA rider produces unjust and unreasonable rates as applied to all residential rate classes (R and RT), and specifically its low income customers and that the Commission should require UGI to allow the pilot to end on October 31, 2027, as scheduled. If the Commission permits UGI to continue its WNA pilot, it should impose the additional conditions recommended in my testimony and, in that event, I do not oppose a modest increase in the customer charge as recommended in my testimony. Finally, the Commission should accept my recommendations regarding changes to UGI's purchase of receivables program and other recommendations that I am making concerning customer service and universal service programs and tariff changes.

II. Overview of Rate Request and Role of Regulation

A. UGI's Rate Request

Q: Please describe UGI's requests.

A: UGI seeks to increase the rates of its customers by $99.368 million per year, of which it seeks to recover approximately $74.675 million or 75.2% of the proposed rate increase from residential customers.[2] For residential customers, this would result in an increase in rates of 9.4%. On an individual customer basis, UGI projects the monthly bill of an average residential customer using 68.7 ccf of gas each month would increase by $9.91 per month.[3] This would increase their bill from $113.64 per month on average to

[2] UGI Statement No. 1 at 5:22; Filing Requirements, UGI Gas Exhibit E at 1 (Summary – Total Rev).
[3] UGI Statement No. 1 at 8, Table 1.

$123.55 per month on average.[4] According to UGI, when it looks into the future, it asserts that its current rates are inadequate as they would produce – without rate relief – a 7.7% return on equity as of the end of the of the Fully Projected Future Test Year (FPFTY) on September 30, 2027.[5] UGI states that it requires a return on common equity of 10.75%.[6] UGI also seeks to use its equity-skewed capital structure comprised of 54.25% equity and 45.75% debt with an embedded debt cost of 5.17%.[7] Combined, UGI seeks an overall rate of return of 8.20%.[8]

UGI seeks to collect its revenue requirement assigned to its residential customers through an increase in its residential customer charge and an increase in its volumetric charge.[9]

Table 1 - Proposed Increase

Description	Current Rate	Proposed Rate	Increase ($)	Increase (%)
Customer Charge (per month)	$16.25	$23.00	$6.75	41.5%
Distribution Charge (per Mcf)	$6.3317	$6.8383	$0.5066	8.0%

UGI also seeks to continue its WNA pilot for another five years through October 31, 2032. This pilot was first authorized by the Commission in its 2022 gas rate case at Docket No. R-2021-3030218, and which was modified in its 2025 rate case pursuant to a compromise settlement that was approved by the Commission in September 2025 at

[4] Id.
[5] UGI Statement No. 1 at 6.
[6] UGI Statement. No. 8 at 65.
[7] Filing Requirements, UGI Gas Exhibit A, Fully Projected Future, Exhibit B-7 at 1 of 1.
[8] Id.
[9] Filing Requirements, UGI Gas Exhibit E at 2 (Rate R).

Docket No. R-2024-2052716.[10] Pursuant to the terms of the Settlement, the pilot will end on October 31, 2027, unless reauthorized by the Commission.

B. Role of the Regulation

Q: What is the role of the Public Utility Commission in this case?

A: If you are a residential customer who lives in UGI's service territory and you need gas distribution service, you must buy it from UGI at the prices set by the Commission. You cannot buy it from anyone else at any other price. Because its customers do not have a choice to buy gas distribution service from anyone else or at any other price, UGI must receive the Commission's approval to increase its distribution rates. Consumers rely on the Commission to set rates that are fair, just, and reasonable and the Commission's job is to stand in the gap for consumers to protect them from a utility's monopolistic overreach. That is, UGI – like all monopolies with no competitors – is inclined to seek rates that are excessive and extractive. The Commission's job is to check this tendency and balance the interests and legal rights of consumers with the interests and legal rights of the utility. Overall, the purpose of rate regulation is to determine the just and reasonable rates necessary to support prudent investment that is in the public interest, and which allows a utility to earn a fair rate of return on its investment.

In addition, consistent with the Commission's suspension order in this proceeding, the Commission and parties have been charged with examining all UGI's proposed and existing rates, rules, and regulations.[11] To fulfill this charge, the Commission must

[10] Pa. P.U.C. et al. v UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716, Order (Order entered September 11, 2025); UGI Utilities, Inc.-Gas Division Tariff, Supplement No. 37 to UGI Gas – Pa. P.U.C. No. 7, Sixth Revised page No. 54. ("WNA Rider").

[11] Pa. P.U.C. v. UGI Utilities, Inc. – Gas Division – Docket No. R-2025-3059523, Order at ¶¶ 1 and 4 (Order entered February 19, 2026). Vice Chair Barrow issued a statement at the time of suspension that

determine not only whether all rates sought (how much) and the chosen rate designs to collect that revenue (how those rates are collected) are just and reasonable, but must also consider the impact of rates on consumers.[12] This includes whether the programs designed to assist consumers of limited economic means are sufficient to allow them to continue to afford to maintain and access service on reasonable terms and conditions.

Q: Why must the Commission consider the impact to consumers in making its determination about the appropriate rate increase?

A: As noted, it is the Commission's job to restrain the monopolistic tendencies of public utilities.[13] Having only one provider of gas distribution service is an intentional system design because multiple companies running mains, pipes, and meters to deliver gas to customers within a geographic area would be inefficient, disruptive, and costly. Thus, in exchange for the right to serve customers without competition for its services, and the requirement and duty to provide service to all customers, gas utilities like UGI submit to price regulation by the Commission, including oversight as to rates and service quality. In exchange, the Commission must permit UGI the opportunity to recover its prudently and reasonably incurred costs, including its cost of debt, and allow it the

requested the parties to address "I urge the parties to take a critical look at the Company's requested rate of return and return on equity (ROE) as well as the capital structure (common equity ratio and debt capital) to ensure reasonableness. Pa. P.U.C. v. UGI Utilities, Inc. – Gas Division – Docket No. R-2025-3059523, Statement of Vice Chair Kimberly Barrow (February 19, 2026). ("Vice Chair Barrow Statement").

[12] Federal Power Comm'n v. Hope Nat'l Gas Co., 320 U.S. 591, 603 (1944) ("[T]he fixing of 'just and reasonable rates', involves a balance of the investor and consumer interests.").

[13] This principle, that it is the job of the PUC to restrain the monopolistic tendencies of public utilities is not new or novel, but rather foundational to the role of regulators. The PUC recently reaffirmed this principle in its Fully Projected Future Test Year Final Rulemaking Order when it said: "Inherent in the 'cost of providing service' principle of ratemaking is the recognition that public utilities are natural monopolies and that the PUC's oversight through cost-of-service ratemaking regulation serves as a proxy for a competitive market in appropriately restraining, or exerting downward pressure on, the profit-maximizing prices a monopoly could otherwise charge in the absence of price regulation." Use of Fully Projected Future Test Year 52 Pa. Code Chapter 53, PUC Docket No. L-2012-2317273, Final Form Order at 4 (order entered January 8, 2025), available at: https://www.puc.pa.gov/pcdocs/1874340.pdf (hereinafter "FPFTY Final Form Order"). (Last visited April 10, 2026).

opportunity – though not a guarantee – to earn a fair rate of return on its shareholder investments. This is generally what is referred to as the regulatory compact.

Q: Is the regulatory compact a legal concept?

A: No, it is a public policy concept, but the Commission has statutory authority and discretion to enforce the regulatory compact through the Public Utility Code. Traditionally, this is done through cost-of-service ratemaking that allows a utility the opportunity to earn its allowed rate of return through effective and efficient management. When done correctly, this benefits both customers and the utility.

Q: Please explain.

A: Traditional cost of service ratemaking serves as a substitute for the beneficial aspects of competition because it sets rates only on a forward-going basis.[14] In a competitive market, a business is not guaranteed a profit, instead it must operate efficiently and control its costs. With traditional ratemaking, this is the same pattern for a utility. Rates are set at a point in time, based on the known and measurable costs and need for revenue by the utility, and then only on a forward-going basis. Once set, the rates are fixed until changed by the Commission in subsequent rate cases. This practice encourages the utility to operate efficiently because it cannot increase rates again without Commission permission. As a result, a utility faces the risk of under recovery due to normal business risks and management underperformance. This lack of any guaranteed revenue is a significant and important protection that traditional cost of service ratemaking provides to consumers.

[14] See FPFTY Final Form Order at 4.

Q: Do we have traditional cost of service ratemaking in Pennsylvania?

A: Pennsylvania has modified traditional cost of service ratemaking in several ways, all of which generally reduce risk for the utility and place more of that risk onto consumers. I will discuss three which are relevant to this case:

- Use of Future Test Year or Fully Projected Future Test Year for setting rates to reduce regulatory lag between plant investment and recovery;[15]
- Utilities can propose and the Commission can approve alternative ratemaking methodologies such as the WNA proposed to be continued by UGI in this case;[16] and,
- Approval of a distribution system improvement charge (DSIC) to collect additional revenue over and above the authorized revenue requirement between rate cases.[17]

Each of the above modifies the traditional paradigm and shifts the risk of under recovery of the authorized revenue requirement from the utility to its customers in ways that are often subtle but cumulatively add significantly more certainty for a utility's bottom line. This shift also minimizes the incentive for a utility to operate efficiently as compared to the regulatory lag inherent in traditional ratemaking. Despite offloading risk, utilities still demand returns that are excessive when viewed from the lens of customer's ability to afford rates charged.

[15] 66 Pa. C.S. § 315(e).
[16] 66 Pa. C.S. § 1330.
[17] 66 Pa. C.S. § 1353.

Q: Please explain your concerns.

A: In general, I am concerned that UGI's combined use of multiple alternative rate mechanisms has a compounding negative impact on consumers. First, there is the use of the fully projected future test year or FPFTY. As applied to this case, UGI is projecting forward into the future what it believes its expenses, capital additions, and other costs will be as of September 30, 2027, but is asking that rates be set as of the end of the suspension period, which is October 29, 2026, on a prospective basis. Like all people and businesses, UGI does not know the future. It is making projections about what the world will be like as of the end of September 2027, but it is permitted to charge rates *as if* those projections will in fact be true as of October 2026. For example, UGI sets rates based on projections of utility plant in service by the end of the FPFTY but if it does not meet that goal then customers end of paying rates for anticipated utility plant that was not actually placed into service. Rather than prepaying UGI, they may end up overpaying UGI. The same is true of other projections – such as use per customer, number of customers, operations expenses, and the whole array of issues that are decided in a rate case. That is, effective with the end of the suspension, if any rate increase is granted, UGI would be collecting more revenue than it needs at that time because its rates are set to coincide with the world as UGI projects it to be in September 2027. The effect is to reduce the risk of under collection for UGI and shift it to consumers because consumers are, in effect, paying for the cost of providing gas distribution service based on the projection of those costs in the future – not as the costs exist when the rates go into effect. This reduces the lag associated with ratemaking for UGI by placing more risk – and cost – onto consumers. In my view, UGI's ability to charge rates ahead of when capital is invested and expenses

are incurred should reduce the authorized return that the Commission allows because UGI is already getting the benefit of its own future projections, thereby reducing regulatory lag in its collections. This reduced risk for UGI should result in a lower return on equity (ROE).

Second, the use of WNA further reduces risk for UGI – again shifting that risk onto consumers. I discuss UGI's WNA below in significant detail, but this mechanism allows UGI to spread risks to consumers that were historically born by UGI. In the absence of the WNA, if weather is warmer than normal and customers use less gas, UGI receives less revenue. This incentivizes UGI to accurately project usage and use an appropriate baseline for normalized weather when setting rates. If weather is colder than normal, UGI gets more revenue than it projected when setting rates. That is, UGI is held harmless because it always gets to collect based on normalized weather as opposed to actual weather at the time bills are rendered.

The WNA shifts more risk to consumers than they historically have not had to bear. While it is true that if the weather is colder than normal, UGI provides credit to customers because they used more gas service than was projected, this bi-directionality still means that the benefits and burdens of weather changes are shared between the utility and customers whereas in the past these risks and benefits were placed solely on the utility. Moreover, as discussed in more detail below, the issuance of credits has occurred relatively infrequently since 2022 when the WNA was first put into place. Thus, while bi-directional, the WNA rarely works to the benefit of consumers and allows UGI to offload some of its risk to customers despite UGI being the far more sophisticated party in the

endeavor. In my view, like the use of an FPFTY, this lessening of risk should result in a lower ROE.

Third, UGI has an approved Distribution System Improvement Charge (DSIC) that allows it to currently charge up to 5% additional surcharge on billed distribution revenue once it reaches its fully projected future test year and its net plant in service number. Depending on how long UGI stays out of rate cases in the future, this surcharge has the potential to result in significant additional dollars charged to residential customers. The ability of UGI to charge a DSIC also shifts future risks onto consumers because it reduces PPL's risk that rates set in this case will be insufficient to meet its planned capital plant investments. This too should reduce the ROE required by UGI on its overall ratemaking rate base because the DSIC will enable it deploy capital over and above its rates and earn a return of and on that investment.

Taken together, each of these modifications to traditional ratemaking spread risk from UGI to its customers and require substantial scrutiny by the Commission in its exercise of discretion in setting rates. All of them should result in a lower ROE than the Commission would authorize in their absence.

Q: Will you be addressing each of these issues further through this direct testimony?

A: No. I do not further address the use of an FPFTY or the DSIC. As to the projections for expenses and plant in service at the end of the fully projected future test year, the statutory advocates and others in this case will address the prudency of those expenses and capital costs and whether they will be reasonably and foreseeably incurred. I simply urge the Commission to pay attention to the projections provided by statutory advocates

and others in contrast to those of UGI, as it is critical for consumers that UGI is not permitted to overestimate its expenses or plant in service numbers. As to the DSIC, I do not address it further in this testimony. However, I would urge the Commission to remember the DSIC is a percentage-based charge and as a result, the amount UGI collects in the future when DSIC is utilized is based on its billed distribution revenue amounts. The higher the approved rates in this proceeding, the more DSIC revenue UGI can collect.

Q: Will you be addressing the WNA?

A: Yes. I address the WNA in Section V.B., of my testimony, as a component of UGI's proposed rate design.

III. Impact of the Proposed Rate Increase on Low Income Households

Q: What is the purpose of this section of your testimony?

A: To describe the impact that UGI's existing rates and its proposed rate increase has on the ability of its low income customers to reasonably afford and maintain gas service to their homes.

A. Overview of Residential Rate Class

Q: Please summarize UGI's residential rate class.

A: UGI has a general residential rate class Rate R that serves both residential customers on default service (Rate R) and customers who have elected to receive gas commodity service from a natural gas supplier other than UGI (Rate RT). There is no material distinction between these two rate classes for purposes of cost allocation, either at the class level or in terms of the rate design.

Q: How do low income customers fit within Rate R and RT?

A: The vast majority of UGI's estimated low income customers – 82% – are not enrolled in UGI's Customer Assistance Program (CAP) and thus are served under the same rates as all other general residential rate classes – Rate R or RT.[18] Some of UGI's low income customers are enrolled in UGI's CAP, which provides a reduced bill based on the household's income and ability to pay and provides other benefits such as the possibility of earning forgiveness of accrued arrears with each in full payment. Customers enrolled in CAP cannot be served by a competitive gas supplier and must remain on default service.[19] All CAP customers have discounted bills but are otherwise served under Rate R. The difference between a CAP customer's CAP bill and a full undiscounted bill is recovered as CAP credits through UGI's Rider F-Universal Service Program and charged to other residential customers.[20]

Q: How much of UGI's requested $99.4 million annual rate increase is it proposing to allocate to residential customers?

A: UGI is proposing to allocate approximately 75.2% of the increase or $74.7 million to residential customers, with the remainder assigned to small business customers, a small amount charged to Rate classes DS and LFD. UGI is proposing a rate *decrease* for all other rate classes.[21] Of this $74.7 million, I estimate the UGI is seeking to require

[18] As of January 2026, UGI reports that 26,250 customers were enrolled in its CAP. As of August 2025, UGI witness Brian Meilinger reports that UGI serves 143,404 estimated low income customers. UGI Statement No. 12 at 16. Thus, as of January 2026, 117,154 estimated low income customers – or 82% – were not enrolled in CAP. See UGI Response to CAUSE-PA 1-6, Attachment, Attached hereto at Appendix B.

[19] I support this policy as it protects UGI's low income customers enrolled in CAP, as well as other residential ratepayers who pay for the CAP program, from the consistently higher commodity costs charged in the competitive market. See Section IX, infra.

[20] See UGI Tariff Supplement No. 63 to UGI Gas – Pa. P.U.C. No. 7, Seventeenth Revised Page No. 58, Rider F – Universal Service Program.

[21] UGI Exhibit E, Proof of Revenues, Page 1 of 7.

its confirmed low income customers to pay approximately $7 million of the increase based on the fact that these customers comprise 9.4% of the residential customer class on average between 2023-2025.[22] Even this may be a low estimate because of the difference in usage between low income households and all residential customers.

Q: Why does it matter what percentage of the increase is functionally assessed to UGI's low income customers?

A: As noted later in this section, low income customers who are not enrolled in CAP cannot consistently afford to maintain gas service even at the current rates being charged by UGI, and they certainly cannot afford to pay rates at the increase sought by UGI. However, UGI's CAP participation rates are insufficient relative to the need. Furthermore, UGI's CAP costs are currently only assessed to residential customers, even though all customer classes benefit when CAP customers remain connected to service, and thus, in my view, the allocation of any revenue increase across rate classes must consider the burdens imposed on those customers bearing the heaviest increase and those most at risk of being priced out of the market for essential gas services to their home.

Q: Please explain what you mean when you state that the allocation of any revenue increase must consider the burdens imposed by customers within rate classes?

A: First, I want to note that except for my proposal in Section VII below to reallocate universal service costs, I am not taking a specific position on the allocation of the overall revenue requirement across rate classes. That is, I am not taking a position on whether

[22] This calculation is based on an average of 620,818 residential customers from 2023-2025 and average of 58,170 Confirmed Low Income Customers over that same period. See UGI Response to CAUSE-PA 1-5, Attachment, attached hereto at Appendix B and Attachment SRR-RR-3, UGI Filing Requirements. Calculations provided in Cicero Miscellaneous Workpapers, Tab 4.

the cost allocation proposed by UGI is methodologically sound. While a cost allocation guides allocation of the granted revenue requirement increase across classes, cost of service is only a guide not a master, and the Commission must consider other factors before finally allocating any granted revenue increase across customer classes.

UGI itself articulates a similar principle through its choice of allocation and its decision to propose to move all rate classes closer to the overall system rate of return.[23] UGI argues that this reduces subsidies occurring between classes[24] and thus, is a form of the argument that I make above that any rate allocation process must consider relative burdens between classes when apportioning the proposed revenue increase to its rate classes. While UGI prioritizes cost of service as the "polestar" of cost allocation,[25] thus moving rate classes closer to their relative cost of service, this is not the only consideration when determining whether rates are just and reasonable.

Notwithstanding UGI's assertions that it is adhering to principles of cost causation in its prioritization of relative rates of return, the Commission should look with suspicion at UGI's cost allocation because it is proposing to provide some rate classes (XD - Firm and Interruptible) a rate decrease based on the fact that the other rate classes are paying higher relative rates of return and thus, according to UGI, overpaying their cost of service.[26] It is my view that if an increase is approved, all rate classes should share the associated pain keeping in mind principles of cost causation and gradualism. This is particularly true when a utility seeks to impose on the most vulnerable customers – those

[23] UGI Statement No. 10 (Taylor) at 20:10-12.
[24] Id. at 20:10.
[25] See Lloyd v. Pa. P.U.C., 904 A.2d 1010 (Pa. Cmwlth. 2006), appeal denied, 591 Pa. 676, 916 A.2d 1104 (2007).
[26] UGI Exhibit E, Proof of Revenues, Total Revenue, page 1 of 7.

households experiencing poverty – a significant increase while at the same time providing a rate decrease to far more sophisticated customers with far more economic resources to bear an increase.

B. Low Income Customer Demographics

Q: Who qualifies as a low income customer?

A: The term "low income customer" is defined in the Commission's regulations and includes any residential customer whose household income is at or below 150% of the Federal Poverty Level (FPL).[27] Most utility assistance programs – including UGI's CAP – require households to have low income to receive assistance; however, there are some exceptions, including UGI's hardship fund which allows customers with income up to 250% FPL.[28]

Q: Please describe the FPL.

A: The FPL is a measure of poverty based exclusively on the size of the household and its income. It does not consider the composition of the household (i.e. whether the household consists of adults or children, and the relative associated costs) or variations in the cost of basic needs in different geographic locations. A family of four with household income of exactly 150% FPL has a gross annual income of $49,500 ($4,125/month).[29] This is significantly more income than most households who are receiving utility assistance. UGI reports that the average annual income of confirmed low income

[27] See 52 Pa. Code § 54.72 (Defining low income customers for the purposes of Universal Service programs and reporting).
[28] 2020-2025 UGI Universal Service & Energy Conservation Plan, 2022-2025, Docket Nos. M-2017-2598190; M-2019-3014966 (2020-2025 USECP) at 5, 22-23.
[29] See US Dept. of Health & Human Services, HHS Poverty Guidelines for 2026, available at: https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines. (Last visited March 13, 2026). Attached to my testimony at Appendix C, Cicero Exhibit C-1 is a table from U.S. HHS that shows the 2026 FPL at different household sizes and multiples.

customers is $20,146,[30] and the average annual income of CAP customers is $17,208.[31] This is substantially less than a household needs to meet their basic expenses in any of the counties that UGI serves.[32]

Q: Please explain what you mean when you say this level of income is less than a household needs to meet their basic expenses.

A: While the Commission utilizes FPL in its definition of "low income customer", this definition does not capture household income which is necessary to afford basic needs. A more accurate benchmark meant to assess how much income a household needs to live without assistance in Pennsylvania is the Self-Sufficiency Standard.[33] This Standard is a benchmark used to assess how much income a household needs to live without assistance in Pennsylvania. It measures the income that a family must earn to meet its basic needs and consists of the combined cost of six (6) basic needs – housing, child care, food, health care, transportation, and taxes – without the help of public subsidies.[34] Unlike the FPL, which does not change based on geographic location or family composition, the Self-Sufficiency Standard accounts for the varied costs of the six basic needs in different geographic areas and for differently aged household members.[35]

Based on the 2024 Self Sufficiency Standard, a family of four (consisting of 2 adults and 2 school-aged children) living in the counties served by UGI requires an income ranging from $69,077 to $104,762. This is approximately between $19,577 (140%) and

[30] UGI Response to CAUSE-PA 1-17. Attached hereto at Appendix B.
[31] UGI Response to CAUSE-PA 1-18. Attached hereto at Appendix B.
[32] Self-Sufficiency Standard, available at: http://www.selfsufficiencystandard.org/Pennsylvania. (Last visited March 31, 2026*).*
[33] Id.
[34] See PathWays PA, Overlooked and Undercounted 2019 Brief: Struggling to Make Ends Meet in Pennsylvania, available at: http://www.selfsufficiencystandard.org/Pennsylvania. (Last visited March 31, 2026).
[35] Id.

$55,262 (211%) per year *more* than a four-person household with annual income at 150% FPL – the maximum amount permitted to be eligible for CAP.[36]

Q: If the Commission does not use the Self Sufficiency Standard as a measure of eligibility for assistance, why is this information important?

A: It is important for context. The Self Sufficiency Standard helps illuminate the full scope of utility insecurity and the need for utility rates and rate design to not exacerbate the precarious financial position of those UGI customers who, while not considered low income by the Commission nevertheless struggle to make ends meet each month.

The simple reality is that the number of households in need of assistance and the amount of assistance needed per household is far greater than UGI, the Commission, or many parties have historically acknowledged. Given that households subsisting at more than double the poverty level within UGI's service territory cannot afford necessities, there is little to no chance that households at less than 150% of the poverty level can afford essential utility service without significant assistance. This fact must be considered by Commission in exercising its discretion over the authorized ROE, rate design, and overall revenue requirement – as well as programs and terms and conditions of service that help ensure universal access to service, which is at the heart of the regulatory compact.

Q: How does UGI determine how many low income customers are in its service territory?

A: UGI is required to track its low income customer population in two ways: (1) confirmed low income customers and (2) estimated low income customers.

[36] See Id. (2024 Pennsylvania Data Set).

Q: How many confirmed low income customers does UGI report?

A: As of January 2026, UGI reported 68,289 customers (or 11% of residential customers) confirmed low income customers.[37] As I explain later, I believe this number should be much higher based on additional data that UGI has collected that would reasonably place additional customers in a low income designation.

Q: How many estimated low income customers does UGI report?

A: As of August 2025, UGI reported 143,404 estimated low income customers to the Commission (or 23% of residential customers).[38] This estimate was developed in accordance with the Commission's Bureau of Consumer Services (BCS) specified methodology, which "derived the estimated number of low income customers by calculating the number of UGI Gas customers in each county of its service territory multiplied by the 2019-2023 American Community Survey 5 Year Estimates census data provided by the Bureau of Consumer Services for that county."[39]

Q: Does UGI provide another estimated low income customer count in its testimony?

A: Yes. UGI witness Brian Meilinger asserts that the Commission's methodology used to calculate estimated low income customers "should be considered an over estimation and referenced with caution."[40] He argues that the Company's Low Income Customer Assessment and Outreach Pilot undertaken with a proprietary Experian-developed method identified an "estimated" low income population of 98,785 customers at or below

[37] UGI Response to CAUSE-PA 1-5, Attachment; see also UGI Response to CAUSE-PA 1-7, Attachment (UGI reported 636,412 residential customers as of Jan. 2026). Attached hereto at Appendix B.
[38] UGI Statement No. 12 at 16. see also UGI Response to CAUSE-PA 1-7, Attachment (UGI reported 621,606 residential customers as of Aug. 2025). Attached hereto at Appendix B.
[39] UGI Statement No. 12 at 16.
[40] Id.

150% FPIG in the fall of 2023. He further argues that the Experian estimate "uses actual demographic income data of UGI customers and identifies significantly less customers."[41] In discovery, UGI indicated that the updated Experian number is 96,137 as of January 2026.[42]

Q: Do you agree with Mr. Meilinger?

A: No. Mr. Meilinger's testimony makes it clear that for the 96,137 low income customers identified through the Pilot as of January 2026, the Company used Experian to obtain actual demographic information for the households that would reasonably place them in a low income designation. UGI explained in discovery that, while it does not have actual income data for all customers, "[f]or the January 2026 data assessment, there was a 90% match rate on name and address."[43] In other words, the Company now has information that reasonably places 90% of the households included in the Experian survey in the low income category. Thus, under the Commission's regulatory definitions, these households should be classified as **confirmed** low income households, not estimated low income households. As part of the Settlement in its last rate case, UGI adopted the definition of "confirmed low income" consistent with 52 Pa. Code § 62.2.[44] The Commission defines "Confirmed low-income residential account" as:

> Accounts **where the NGDC has obtained information that would reasonably place the customer in a low-income designation**. This information may include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).[45]

[41] Id.
[42] UGI Response to CAUSE-PA 6-17. Attached hereto at Appendix B.
[43] Id.
[44] UGI Response to CAUSE-PA 1-4. Attached hereto at Appendix B.
[45] 52 Pa. Code § 62.2 (emphasis added).

The Commission has explained that section 62.2 defines the "Confirmed Low-Income Customers" designation in broad terms, and while it provides examples of information that a utility may rely upon when making such designation, this is not an exhaustive list.[46] The enumerated examples given do not imply the exclusion of others if the information is obtained by the Company and would reasonably place the customer in a low income designation.[47]

If UGI has used Experian to collect **actual demographic information** for the household indicating that they are at or below 150% FPL, this information would reasonably place the customer in a low income designation, and these accounts should be designated as confirmed low income. At the very least, this should be the case for the 90% of households for whom UGI matched names and addresses with demographic income data. If this correction is made, then UGI's confirmed low income customer count would increase from 68,289 (11% of residential customers) to 96,137 (~15% of residential customers).

Furthermore, I disagree with Mr. Meilinger that the Commission's estimated low income customer count is over inclusive. It uses reasonable and consistent methodologies to ensure accurate comparisons across the state and thus should be relied on for assessing the number of eligible customers and the effectiveness of UGI's universal service program participation and outreach.[48] Therefore, for purposes of evaluating the impact of UGI's rates and terms and conditions of service – including the

[46] See Pa. PUC v. PGW, Docket No. R-2023-3037933, Final Order at 221 (Entered Nov. 9, 2023) ("Section 62.2 of our Regulations defines the "Confirmed Low-Income Customers" designation in broader terms, as it provides examples of information . . . and not an exhaustive list. In other words, the enumeration of these examples of information in the regulation does not imply the exclusion of others if the information is obtained by the Company and would reasonably place the customer in a low-income designation.")
[47] Id.
[48] See Id. at 222.

adequacy of its universal service programs – it is more accurate to utilize the census-based estimated low income customer counts.[49] Which would be an estimated low income customer count of 143,404.

C. Impact of Rate Increase on Low Income Households

Q: How would UGI's proposed rate increase impact low income households?

A: UGI's proposed rate increase would severely and detrimentally impact the ability of low income families to afford their monthly expenses and further hinder their ability to maintain gas service. Low income families already struggle to make ends meet each month and are forced to make untenable choices between affording utility services and other basic necessities – such as food, medicine, and housing.

To contextualize the impact of the proposed rate increase, it is helpful to look at the relative energy burden of low income households. To be affordable, a household's total housing costs – *including utility costs* – should account for no more than 30% of a household's total income.[50] According to formal Commission policy, to be considered affordable, rates should fall below the following energy burdens:

Table 2: PUC CAP Policy Statement Maximum Energy Burdens[51]

Income Level (% FPL)	Natural Gas Heating	Natural Gas Heating and Electric Baseload Combined
0-50%	4%	6%
51-100%	6%	10%
101-150%	6%	10%

[49] See Id. at 222.
[50] U.S. Census Bureau, Nearly Half of Renter Households Are Cost-Burdened, Proportions Differ by Race, available at: https://www.census.gov/newsroom/press-releases/2024/renter-households-cost-burdened-race.html. (Last visited April 6, 2026).
[51] Policy Statement on Customer Assistance Program, 52 Pa. Code § 69.261-69.267

UGI's low income customers who are not enrolled in CAP have burdens that are significantly higher than these, and the proposed rate increase would materially increase the portion of low income household energy burdens attributable to their gas bill. The table below uses data provided by UGI in discovery to analyze the burden impact for confirmed low income households not in CAP (Non-CAP CLI) monthly. This table uses 2023-2025 average usage data. I then compare the bill at current rates versus the bill at proposed rates. Using this same information, the last column shows the monthly percentage of income low income customers must allocate towards their gas bills at proposed rates.

Table 3: Impact Rate Increase Impact Non-CAP CLI Customers[52]

Month/Year	3 Year Mean Non-CAP CLI Customers Mcf/Month	Bill at current rates ($)	Bill at proposed rates ($)	Percentage of Monthly Income Current Rates	Percentage of Monthly Income Proposed Rates
Jan-25	16.5	$250.20	$264.61	15%	16%
Feb-25	16.3	$247.36	$261.68	15%	16%
Mar-25	12.8	$197.75	$210.43	12%	13%
Apr-25	8.4	$135.38	$146.00	8%	9%
May-25	3.9	$71.59	$80.11	4%	5%
Jun-25	2.2	$47.49	$55.21	3%	3%
Jul-25	1.6	$38.99	$46.43	2%	3%
Aug-25	1.4	$36.15	$43.50	2%	3%
Sep-25	1.6	$38.99	$46.43	2%	3%
Oct-25	2.4	$50.33	$58.14	3%	3%
Nov-25	6.2	$104.19	$113.79	6%	7%
Dec-25	13.6	$209.09	$222.15	12%	13%
Annual Avg/Month	*7.2*	*$118.96*	*$129.04*	*7%*	*8%*

[52] See UGI Response to OCA 4-6, Attachment, 3-year Mean by Month 2023-2025, Attached hereto at Appendix B. UGI Response to CAUSE-PA 1-17, Attached hereto at Appendix B. Calculations are contained in Cicero Workpapers distributed with testimony.

As shown here, if UGI's proposal is approved, the annual gas bill energy burden for non-CAP confirmed low income customers with average income and average usage would increase by a full percentage - from approximately 7% to approximately 8% over the course of the year. The energy burden for these customers **during the winter months** is already far above what is considered affordable, and UGI proposes to raise it even higher. The amount a low income household pays each month varies depending on their usage – just as it would for all residential customers. In January, when usage is highest, low income (non-CAP) households with average income and median usage are charged as much as 15% of their income at current rates. At proposed rates, the average energy burden for these same households would increase two full percentage points - to 16%. Note that these percentages should be compared to the maximum recommended burden of 6% as they do not include a household's electric bill burden. Thus, the energy burden for low income customers not enrolled in CAP is already far above what is considered affordable, and UGI proposes to raise it even higher.

Q: In addition to high energy burdens, discussed above, is there other evidence that UGI's low income customers are struggling to afford gas services even before any rate increase is approved?

A: Yes. UGI's low income customers carry a disproportionate amount of customer debt and are far more likely to have their service involuntarily terminated for nonpayment. If UGI's proposed rate increase is approved, these pronounced disparities will increase, as will the risk of consequences to the health and safety of low income customers and their households and the corresponding level of uncollectible expenses which are recovered from all ratepayers.

First, UGI low income customers have markedly higher rates of service terminations for nonpayment compared to UGI's residential customers as a whole, as illustrated by the following Table:

Table 4: Involuntary Termination Rate (2023-2025)[53]

Year	All Residential Term. Rate[54]	Residential Term Rate Excluding CLI[55]	All CLI Term Rate[56]	Non-CAP CLI Term Rate[57]	CAP Term Rate[58]
2023	5%	4%	18%	20%	8%
2024	5%	4%	18%	21%	10%
2025	5%	3%	19%	26%	7%

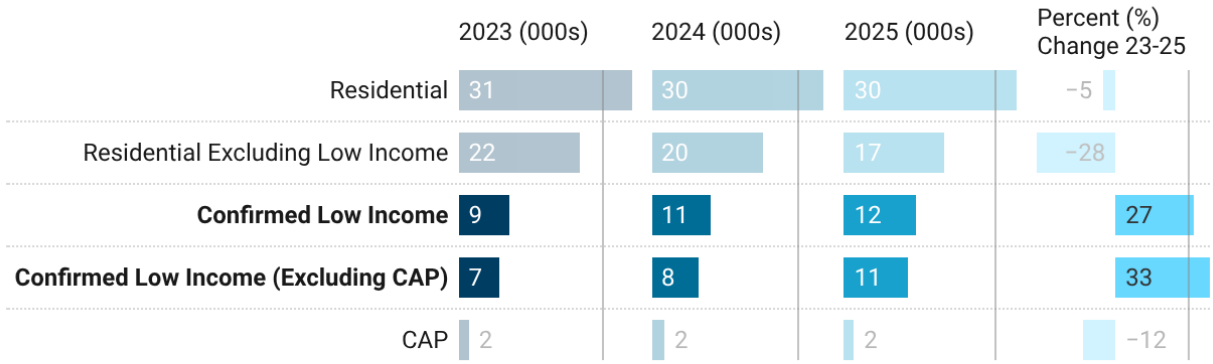
Table 4 shows that confirmed low income customers who are not enrolled in CAP have a utility termination rate that is 400%-500% higher than all residential customers and 500%-850% higher than residential customers who are not low income. Even low income customers in CAP have rates that are more than 200% higher than non-low income customers. Critically, however, for low income customers, enrollment in CAP reduces termination rates significantly as compared to paying full tariff rates.

The overall termination trends for UGI's service territory from 2023 through 2025 reveal another significant and concerning shift: while total residential terminations have remained relatively stable, including terminations of customers enrolled in CAP (even

[53] Termination rates were calculated using the termination data in UGI Response to CAUSE-PA 1-14, Attachment, applied to the average number of customers in each category for each year.
[54] UGI Response to CAUSE-PA 1-7, Attachment (for residential customer count). Attached hereto at Appendix B.
[55] UGI Response to CAUSE-PA 1-9(a), Attachment (for residential customers, excluding confirmed low income and CAP). Attached hereto at Appendix B.
[56] UGI Response to CAUSE-PA 1-5, Attachment (for confirmed low income customer count). Attached hereto at Appendix B.
[57] UGI Response to CAUSE-PA 1-9(b), Attachment (for confirmed low income customers, excluding CAP). Attached hereto at Appendix B.
[58] UGI Response to CAUSE-PA 1-6, Attachment (for CAP customers count). Attached hereto at Appendix B.

slightly decreasing), terminations specifically for CLI customers in general and those not enrolled in CAP specifically have increased sharply. This is shown in the visual below:

Chart 1: Terminations (2023-2025)



Termination Numbers and Percentages Rounded

Source: Created by Patrick Cicero from UGI Discovery Responses • Created with Datawrapper

As can be seen from the above chart,[59] terminations for the poorest customers *increased* by 27% during the last three-year period – and for those not enrolled in CAP the increase was 33% – even though terminations for all other groups decreased during this period. The financial burden of rates and risk of termination are becoming increasingly concentrated within the UGI's low income customer base who are not receiving program assistance. This is the group of households who are most affected by the increase proposed by UGI.

In fact, in 2025, more than one-third (36.4%) of all residential gas shut-offs were of confirmed low income customers not enrolled in CAP,[60] despite these customers only

[59] The data sources used to create Chart 1 were various responses provided by UGI is discovery and are outlined and provided as a part of my workpapers. The underlying interrogatory responses are UGI's Response to CAUSE-PA 1-7, Attachment, UGI Response to CAUSE-PA 1-9(a) attachment, and UGI Response to CAUSE-PA 1-9(b), attachment. All are attached hereto at Appendix B.

[60] In 2025 UGI reported 29,715 residential payment based terminations, 10,825 of which affected low income customers not enrolled in CAP. See UGI Response to CAUSE-PA 1-14, Attachment. Attached hereto at Appendix B.

accounting for 7% of customers.[61] These facts, in addition to the stark disparities in termination rates for low income families shown in Table 4, especially those not enrolled in CAP, will deepen if UGI is permitted to increase its basic rates of gas service without addressing the unaffordability of rates.

Simply put, there is a growing need for more targeted and strategic outreach to these high-risk customers to ensure that they have every opportunity to enroll in CAP before they experience service loss. Enrollment in CAP is the most significant, preventative thing that UGI can do to reduce the rate of service loss for low income customers, but the ability of UGI's CAP to mitigate unaffordability is immaterial if families are not enrolled. This makes UGI's significant and pervasive undersubscription to the program, as I discuss in Section VI.B., below, even more critical.

Q: Are there other indicators that UGI's low income customers struggle to afford gas service?

A: Yes. UGI's low income customers also carry substantially higher levels of arrears compared to non-low income residential customers. Table 5 demonstrates that the average arrearages carried by CLI customers are consistently higher than the average arrears carried by non-low income customers:

Table 5: UGI Customer Arrearage and Debt Levels (2024-2025)[62]

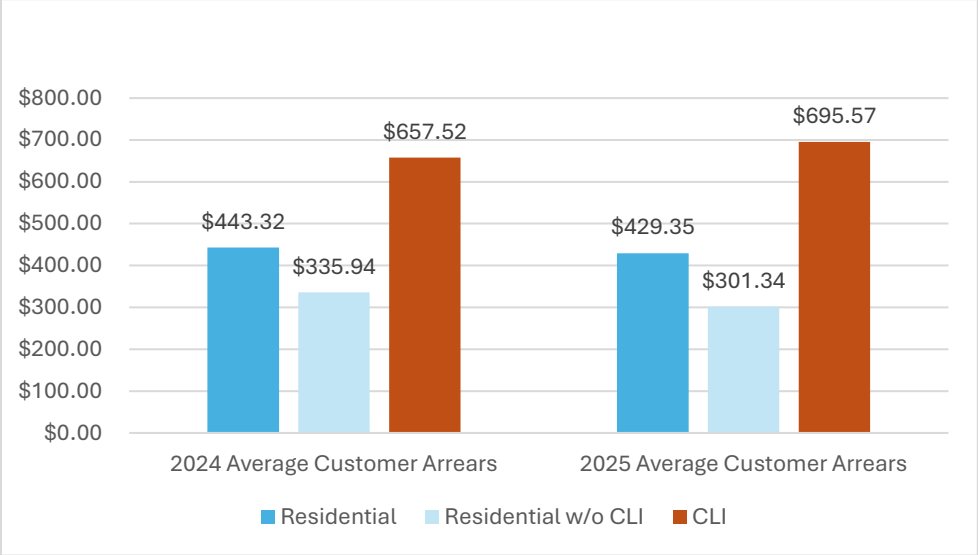
	2024 Average Arrears	2025 Average Arrears
Residential	$443.32	$429.35
Res. w/o CLI	$335.94	$301.34
CLI	$657.52	$695.57

[61] UGI reported a monthly average of 627,819 residential customers and 42,288 non-CAP CLI customers (7%) in 2025. See UGI Response to CAUSE-PA 1-14, Attachment; UGI Response to CAUSE-PA 1-7, Attachment. Both attached hereto at Appendix B.

[62] UGI Response to CAUSE-PA 1-22, Attachment (Average of all months). Attached hereto at Appendix B.

This same information is presented in Chart 2, below.

Chart 2: UGI Customer Average Arrears (2024-2025)[63]



This data demonstrates that the average arrearages carried by confirmed low income customers are approximately twice as high as those carried by non-low income residential customers. Notably, in 2025, total confirmed low income arrears comprised more than half (51%)[64] of total residential debt, despite only accounting for only 10% of all residential customers reported in 2025.[65]

These indicators demonstrate that UGI's low income consumers already have excessive energy burdens and struggle to pay for gas service leading to disproportionate arrearages and terminations rates. Low income customers will likely experience increased arrears, increased termination, and increased payment trouble if the proposed rate increase is approved.

[63] UGI Response to CAUSE-PA 1-22, Attachment. Attached hereto at Appendix B.
[64] UGI Response to CAUSE-PA 1-22, Attachment ($30,138,452.10 of $58,701,299.07 residential debt was attributed to confirmed low income customers in 2025). Attached hereto at Appendix B.
[65] UGI reported a monthly average of 627,819 residential customers and 65,636 (10%) CLI customers in 2025. See UGI response to CAUSE-PA 1-5, Attachment; UGI Response to CAUSE-PA 1-7, Attachment. Attached hereto at Appendix B.

Q: Will UGI's Customer Assistance Program (CAP) protect low income households from the financial impact of the proposed rate increase?

A: Not entirely. UGI's CAP is a critically important affordability program and is successful in reducing low income termination rates and arrearage levels by providing a fixed payment amount (based on a percentage of income, average bill, or minimum payment); arrearage forgiveness over 36 months; and exemption from late payment fees.[66] However, the program will not fully shield the Company's low income customers from the impact of the proposed rate increase because the program is severely undersubscribed, and thousands of CAP customers receive average bills and will bear the full impact of the proposed rate increase. Specifically:

- Approximately 82% of UGI's estimated low income customers are not enrolled in CAP, limiting the ability of CAP to mitigate unaffordability at present and proposed rates.[67]

- As of March 2026, 7,291 out of 26,641 reported accounts – or 27% -- had their CAP amounts calculated based on their average monthly bills.[68] These customers will experience an increase (up to their respective percentage of income payment amount) in their bills immediately upon their next quarterly budget bill adjustment.

Q: Does LIHEAP mitigate the harm of the proposed rate increase on low income households?

A: No. LIHEAP is a federal program designed as a supplement to assist households to better afford energy services, but the program only reaches a small fraction of eligible households and is not adequately funded to address existing unaffordability – let alone increased unaffordability because of increased rates. The program is subject to annual

[66] UGI USECP 2020-2025 at 22-24.
[67] UGI Response to CAUSE-PA 1-6, Attachment (As of January 2026, UGI reports that 26,250 customers were enrolled in its CAP), Attached hereto at Appendix B; UGI Statement No. 12 at 16 (UGI's most recent estimated low income customer count was143,404 estimated low income customers).
[68] UGI Response to CAUSE-PA 1-3. Attached hereto at Appendix B.

reauthorization and allocation of funding by the federal government, a fact brought into sharp focus by the recent federal government shutdown. The shutdown delayed the opening of the 2025-26 LIHEAP season by a month, throwing low income households into uncertainty as they faced the prospect of losing critical heating assistance.[69] Although the end of the federal government shutdown enabled the release of LIHEAP funding for the 2025-2026 LIHEAP season, the reality is that LIHEAP has never been adequately funded to eliminate UGI's excessive low income termination, arrears, and energy burden levels – let alone mitigate the impact of UGI's proposed rate increase. For the second year in a row, LIHEAP is proposed for elimination in the federal budget.[70] In my estimation, it is inappropriate to consider the potential availability of LIHEAP funds as a factor in setting rates.

Further, while LIHEAP is a critically important program and provides life-sustaining assistance to those in need, the program is only intended to provide supplemental assistance and is not enough to mitigate the financial harm of a rate increase. UGI's proposed rate increase, if authorized, will also consume a substantial portion of LIHEAP assistance currently received by UGI's customers. In the 2025-26 LIHEAP program year, the minimum Cash grant is just $200.[71] The average statewide LIHEAP cash grant for PY

[69] See Pa. Dept. of Human Services, Due to Federal Government Shutdown, Opening of the 2025-26 Low-Income Home Energy Assistance Program (LIHEAP) Season Delayed to December, available at: https://www.pa.gov/agencies/dhs/newsroom/due-to-federal-government-shutdown--opening-of-the-liheap-season. (Last visited March 29, 2026).
[70] Nat'l Energy Assistance Directors Association (NEADA), Press Release: President's FY 2027 Budget Eliminates Federal Funding for LIHEAP (Apr. 3, 2026), https://neada.org/wp-content/uploads/2026/04/PresidentBudget2027Response.pdf.
[71] Pa. LIHEAP State Plan, FY 2026, at ii, available at: https://www.pa.gov/content/dam/copapwp-pagov/en/dhs/documents/services/assistance/documents/heating-assistance_liheap/2026-liheap-state-plan.pdf *(Last accessed March 29, 2026).*

2025-26 as of April 2, 2026 is $275 for gas utilities.[72] Under UGI's proposed rate increase the average residential heating customer bill will increase by $9.91 per month, or 118.92 annually.[73] Thus, UGI's proposed increase would consume 43% of the LIHEAP grant to a typical gas consumer.

Q: Do you have any proposals that could help remediate the financial impact of UGI's proposed rate increase on low income customers?

A: Yes. I have several recommendations to help mitigate the financial impact of UGI's proposed rate increase on low income households. As outlined more fully below, the Commission should deny UGI's rate increase in its entirety as the record evidence shows that it has sufficient revenue to earn a fair rate or return and provide safe and reliable service. If the Commission is inclined to grant an increase, it should reduce the requested ROE and adjust the Company's capital structure for ratemaking purposes. Both would have an immediate and tangible impact on the overall revenue requirement. I make several recommendations below about how to structure UGI's rate design and how to spread the cost of the universal service programs to all ratepayers thus reducing the burden on residential ratepayers, including low- and moderate-income customers. Also, as described later in my testimony, UGI should implement additional routine screening to identify low income customers and enroll them in CAP.

[72] Pennsylvania Department of Human Services Energy Assistance Summary report, p. 68 of 136, dated April 4, 2026, attached hereto at Appendix C, Exhibit Cicero C-2.
[73] UGI Statement No. 1 at 8, Table 1.

IV. Revenue Requirement and Rate of Return

Q: Please describe this section of your testimony.

A: In this section of my testimony, I am recommending that the Commission deny UGI's rate increase in its entirety because the record demonstrates that even in the absence of an increase, UGI has sufficient revenue at present rates to maintain safe and reliable service to its customers and has a reasonable opportunity to earn a fair rate or return.

Q: Please discuss the reasons why you do not believe that a rate increase is warranted.

A: Simply put, UGI does not need the increase. For important context:

- UGI last filed for a rate increase in January 2025 that sought $110 million and was permitted to increase its rates by $69.5 million effective October 28, 2025 after the Commission approved a settlement in that proceeding.[74]
- In its 2025 case, UGI projected its needs in its 2025 rate case through its fully projected future test year as of September 30, 2026.
- Even though UGI got the benefit of projecting its needs through that date when it agreed to the settlement, it chose to file this case a mere three months after its rate increase went into effect seeking an additional $99.4 million increase with an effective date of October 29, 2026.

This illustrates the very issue that I highlighted above about the fully projected future test year. In its last rate case, UGI was able to set rates based on its projections about the world as they thought it would be in September 2026 – when their FPFTY in the last case ended. UGI settled a case based on those projections and other compromises with

[74] Pa. P.U.C. et al. v UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716, Order (Order entered September 11, 2025) (Adopting Joint Petition for Settlement allowing a $69.5 million annual rate increase). The 2025 settlement also extended UGI's WNA only through October 31, 2027, unless it is affirmatively extended by the Commission. Pa. P.U.C. et al. v UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716, Joint Petition for Settlement, ¶ 58(e), approved by Final Order entered September 11, 2025).

the parties, yet it apparently decided that it made a bad deal because it chose to file this case three months later. Customers have no such protection and thus bear most of the risk. If UGI determined that it was over-collecting revenue it could choose to remain out of a rate case, but when it determined that it wanted to collect additional revenue, it came in for this filing.

Q: Does the evidence in this case show that UGI is earning significant profits based on its current rates?

A: Yes. There are several metrics that demonstrate UGI has healthy revenue, access to capital, and sufficient returns. First, in the last 5 years (2021-2025) UGI has returned $249 million in dividend payments to its single owner/corporate parent UGI Corporation,[75] and received only $50 million in common equity infusions from its corporate parent. This is shown in Table 6, below.

Table 6: Common Equity Payments and Dividends

Year	Common Equity from UGI Corp to UGI Utilities[76]	Dividend Payment from UGI Utilities to UGI Corp.[77]
2021	$0	$35,000,000
2022	$35,000,000	$0
2023	$0	$0
2024	$0	$135,000,000
2025	$15,000,000	$79,000,000
Total	**$50,000,000**	**$249,000,000**

That is, in the two years during which its last rate case was pending and when this rate case was filed, UGI sent more than $214 million back to its corporate parent in profits.

[75] UGI Response to Standard Data Request – SDR-ROR-20 (stating that UGI Gas does not have publicly traded common stock and has not issued stock as a dividend to UGI Corporation, its 100% common equity owner).
[76] UGI Response to Standard Data Requests – SDR-ROR-11.
[77] UGI Response to Standard Data Requests – SDR-ROR-12.

This is hardly surprising given that ***every quarter since 2021,*** UGI has had net income from its operations totaling more than $2 billion as shown in Table 7, below.

Table 7: UGI Utilities, Inc. – Net Income.[78]

Quarter Ending	Net Income
Mar-21	$ 99,000,000
Jun-21	$ 9,000,000
Sep-21	$ 146,000,000
Dec-21	$ 57,000,000
Mar-20	$ 115,000,000
Jun-22	$ 19,000,000
Sep-22	$ 195,000,000
Dec-22	$ 73,000,000
Mar-23	$ 129,000,000
Jun-23	$ 13,000,000
Sep-23	$ 206,000,000
Dec-23	$ 80,000,000
Mar-24	$ 135,000,000
Jun-24	$ 14,000,000
Sep-24	$ 219,000,000
Dec-24	$ 79,000,000
Mar-25	$ 142,000,000
Jun-25	$ 8,000,000
Sep-25	$ 213,000,000
Dec-25	$ 88,000,000
Total	**$2,039,000,000**

This income was undoubtedly fueled by the actual returns on equity that UGI has been earning over this period. In the last three years alone (2023-2025), UGI has had net profit of more than $613 million.[79] This is not surprising given that over the last three years, UGI has ***never*** had a calculated ROE that was lower than 10.43% and often had returns that were significantly higher. In discovery, UGI provided its calculated ROEs for each of the

[78] UGI Response to OCA 2-18(B), Attachment. Attached hereto at Appendix B.
[79] UGI Response to CAUSE-PA 6-11. Attached hereto at Appendix B.

last three calendar years. They show that UGI is earning significant returns for its sole corporate owner UGI Corporation as shown in Table 8, below.

Table 8 UGI Gas Calculated Return on Equity[80]

Twelve Months Ended	Calculated ROE
12/31/2025	10.43%
9/30/2025	10.43%
6/30/2025	10.85%
3/31/2025	11.32%
12/31/2024	11.12%
9/30/2024	11.17%
6/30/2024	12.11%
3/31/2024	12.39%
12/31/2023	12.19%
9/30/2023	11.43%
6/30/2023	12.94%
3/31/2023	13.45%

This is consistent with what UGI has disclosed in response to discovery from I&E, in which it admitted that for each of the last three fiscal years, its ROE was never below 10.4%:

Table 9: Fiscal Year ROE UGI Utilities, Inc. – Gas Division[81]

	Fiscal 2025	Fiscal 2024	Fiscal 2023
Return on Equity	10.4%	11.2%	11.4%

In discovery, UGI also admitted that "UGI's ability to attract capital needed to make investments that support operating a safe and reliable distribution system was not jeopardized during any quarter in the period from January 1, 2023 through December 31, 2025."[82] The facts are clear: UGI is earning year in and year out significant profits

[80] UGI Response to CAUSE-PA 3-1(a), Attachment. Attached hereto at Appendix B.
[81] UGI Response to I&E-RR-6-D, Attachment. Attached hereto at Appendix B.
[82] UGI Response to CAUSE-PA 3-1(b), Attached hereto at Appendix B.

begotten by significantly high ROEs, and has returned hundreds of millions in dividends to its corporate parent. Yet, it wants its customers to pay more.

Q: All of these are past results, and UGI is making its claim based on a fully projected future test year, why is all this relevant?

A: Because it frames the request that is at issue here. It should be material to the Commission's decision making that ***less than 30 days before it filed this rate case***, UGI was earning a return on equity of 10.43% and had $88 million in net income, and at no point over the last several years – including when it was in its last rate case – did it earn a return less than that percentage or did it have a quarter where it did not have millions of dollars in net income. Additionally, *at current rates*, UGI projects net income of more than $236 million in the current year ending September 30, 2026, and anticipates returning dividends of $60 million to its parent company.[83]

For its part, UGI wants to look past the fact that it has had significant net income, profit, and high ROEs at present and over the past several years and focus only on its projections into the future. That is the nature of future-based ratemaking that is reliant wholly on projections developed by the Company and for the benefit of the parent Company. However, given the extraordinary hardship that UGI's residential customers are facing because of acute and real affordability concerns as outlined above in my testimony, the Commission cannot look past the present reality of UGI's robust financial condition in deciding whether to grant a rate increase. Myopically focusing on the FPFTY for UGI, but not its customers' financial status and ability to pay, would skew the Commission's analysis. If one looks to September 2027 for UGI's low income customers,

[83] See UGI Filing Requirements, Book I, Attachment III-A-13.

the picture is as bleak financially given pending rate increases in this case, as well as overlapping electric, water, and wastewater service territories.

Q: Even focusing on the end of the FPFTY, do you have an opinion about whether UGI's projected ROE is sufficient?

A: Yes, it is sufficient. If rates are not increased, UGI projects that it would yield an overall rate of return of 6.55% which equates to a return of common equity (ROE) of 7.70% for the twelve-month period ending September 30, 2027.[84] UGI witness Bell asserts – without further explanation – that this return "***could*** jeopardize UGI Gas's ability to attract the capital needed to make investments that support operating a safe and reliable distribution system and enhance the reach of capacity of facilities that are required for system growth."[85] When asked about the analysis he relied on to support this conclusion, Mr. Bell indicated that he did no independent analysis and relied on the analysis of UGI Witness Dylan D'Ascendis in his testimony and UGI Gas Exhibit B.[86]

For his part, Mr. D'Ascendis' analysis in testimony and responses to discovery relies on his own cost of capital calculations, which appear geared towards ensuring that the recommended ROE is as high as possible within the range of outcomes that he projects. When asked whether UGI would be able to raise capital in the capital markets at ROEs that were at 8.75% or 9.75%, as opposed to his recommended 10.75%, Mr. D'Ascendis admitted that it was possible, but he did not think that it could be done under "reasonable costs" – by which he meant a "return that is sufficient to maintain the integrity

[84] UGI Statement No. 1 at 6:18-21.
[85] UGI Statement No.1 at 6:24-7:3 (emphasis added).
[86] UGI Response to CAUSE-PA 3-1(d). Attached hereto at Appendix B.

of presently invested capital and permits the attraction of needed new capital at a cost that is competitive with other firms of comparable risk."[87]

Despite these circular answers by Mr. Bell and Mr. D'Ascendis, the reality is that even UGI's own expert concedes that UGI could attract capital without a rate increase.[88] Critically, it is important to note that UGI's source of capital is its parent company, to which is has returned $249 million in dividends in the last few years. Moreover, as shown above, quarter in and quarter out, UGI has earned net income to the tune of more than $2 billion over the last 5 years. Finally, in response to discovery, UGI indicated that despite getting a rate increase in 2025, UGI has not had to have an actual infusion of external capital from the equity markets.[89]

All of these metrics suggest to me that the internally generated cash from its operating subsidiaries – including UGI Gas – is more than sufficient given that UGI's parent company has not had to go to the capital markets in recent years, it would appear that UGI has well capitalized sources to ensure that it continues to have access to sufficient capital and fair rates to ensure that it can maintain safe and reliable service.

Q: Isn't UGI also entitled to the opportunity to earn a fair rate of return on its capital investment?

A: Yes, but an opportunity is not the same as a guarantee. The policy questions the Commission must address are: (1) what is a fair opportunity, and (2) what is a reasonable rate of return? The Commission is vested with significant discretion in determining what constitutes a fair rate of return. While counsel for CAUSE-PA will fully brief the applicable

[87] UGI Response to CAUSE-PA 3-4 and 3-5. Attached hereto at Appendix B.
[88] Id.
[89] UGI Response to CAUSE-PA 3-1(h). Attached hereto at Appendix B.

legal standards as applied to this case, it is important to understand, and it is widely accepted, that there is no single way to arrive at just and reasonable rates and the Commission has board authority on both these matters.[90]

Q: If the Commission does not completely reject UGI's rate increase, do you have an opinion about how much the Commission should authorize?

A: I do not have a recommendation about an increase that the Commission should authorize, because it is my opinion that the Commission should not authorize any increase. However, if the Commission authorizes any increase in rates, it should ensure that the ROE is no higher than necessary and it should impute a ratemaking capital structure that is fairer to consumers. I am making this recommendation because this is one of the many areas where the Commission has an abundance of discretion that it can and should exercise in restraining the monopolistic tendencies of UGI who has captive ratepayers.

Q: What is the impact to the revenue requirement of UGI's request to increase its projected ROE from 7.70% to 10.75%?

A: It is significant. Per my calculations, the dollar impact on the overall revenue requirement for every 10 basis points (0.10%) is approximately $3,000,000.[91] This means that every basis point (0.01%) results in a revenue requirement increase of approximately $300,000 to UGI's customers. At the 305 points that UGI is asking for in this case to take

[90] See Pa. P.U.C. et al. v UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716, Recommended Decision at 22 (August 8, 2025) (quoting Popowsky v. Pa. Pub. Util. Comm'n, 683 A.2d 958, 961 (Pa. Cmwlth. 1996) (adopted by Commission via Order dated September 11, 2025) ("2025 UGI RD"). See also 2025 UGI RD at 51 (citing Duquesne Light Co v. Barasch, 488 U.S. 299, 315-16 (1989) (quoting Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944), and stating "the Commission was not bound to the use of any single formula or combination of formulae in determining rates").

[91] See UGI Gas Exhibit A – Fully Projected, changing tab B-7, line 3 (common equity) to 10.65% and holding all else equal reduces the required revenue increase to $96.361 million from the requested $99.368 million. (99.368 at 10.75% vs. 96.361 at 10.65% = 3.007).

its ROE from 7.70% to 10.75%, UGI is asking the Commission to require customers to pay an additional $91.5 million each year.[92]

Q: Are you saying that out of the $99.4 million increase that UGI is requesting in this case that $91.5 million of that is driven by the Company's request to increase its projected ROE from 7.70% to 10.75%?

A: Yes. The extent of the increase sought by UGI in this case appears to be driven almost entirely by its desire to increase its shareholder return. This is reflected in both its choice of an equity skewed capital structure as outlined above and its decision to present a case that argues that it is entitled to 10.75% return on equity.

Q: Are you recommending a specific lower ROE in this case?

A: As noted above, I am not making a recommendation about the specific cost of equity that should be used to determine UGI's ROE in this case. I encourage the Commission to look at the ROE recommendations by other parties – including those recommended by the OCA – in determining what ROE to authorize. However, the Commission's job as UGI's economic regulator is to ensure that, as a monopolistic enterprise, UGI is not taking undue and unfair advantage of its customers through an ROE that is higher than what it reasonably would need to attract sufficient capital in the market. In my view, this is part and parcel of determining whether rates are just and reasonable. Given that every 10 basis points at the as-filed rate base and capital structure takes $3,000,000 annually from the pockets of ratepayers and puts it into the coffers of UGI and, eventually, net income and profit to shareholders, the Commission should

[92] 10.75% less 7.70% equals 3.05% or 305 basis points. 305 times $300,000 = $91,500,000. Expressed differently, 3o.5 times $3,000,000 = $91,500,000

seriously consider what is a sufficient but not excessive ROE is in its determination of setting rates in this proceeding.

Q: Are there other ways in which the Commission could exercise discretion and protect ratepayers?

A: Yes, it could impute a fairer capitalization ratio. The capitalization ratio is how the overall rate of return is calculated. It consists of debt and equity. Debt is determined by the actual debt issued by the Company at the weighted average cost of debt. The Company places an excessive and undue emphasis on the higher return on equity at the expense of the lower cost of debt and the PUC should impute a capitalization ratio for ratemaking purposes that the evidence demonstrates would be sufficient. In this case, UGI's requested ROE of 10.75% is more than two times higher than its cost of debt at 5.17%. and is at a rate that is significantly higher than the overall return that the major U.S. stock markets have earned over the last 50 or 100 years.[93] UGI has chosen a capitalization ratio for these two costs of 45.75% debt and 54.25% equity. This means that the embedded cost of debt at 5.17% counts less in the overall calculation of the rate of return than the embedded cost of equity at 10.75%.

[93] The Consumer Price Index inflation adjusted return of the Dow Jones Industrial Average from March 1976 to October 2026 (50 years) is 7.52% if all dividends were reinvested. For the past 100 years (March 1926 to March 2026) the return is 6.90%. See DQYDJ Dow Jones Industrial Average Return Calculator, available at: https://dqydj.com/dow-jones-return-calculator/. (Last visited March 30, 2026). There are similar results when looking at the S&P 500. Over the last 50 years, the S&P 500 earned an inflation adjusted return of 7.75% and over the last 100 years, the return was 7.30% See S&P 500 Return Calculator, with Dividend Reinvestment, available at: https://dqydj.com/sp-500-return-calculator/ (Last visited March 30, 2026). I recognize that the calculation of the cost of capital for purposes of setting a return on equity is forward focused not backward looking, I make this observation about the overall stock market returns over the past 50 to 100 years as a real life gut check on UGI's requested ROE. It defies logic, common sense, and reason that one should reasonably expect to earn 10.75% on a safe investment like utilities over a long period of time.

Q: Must the Commission accept the capitalization ratio chosen by UGI?

A: No. The Commission can determine that the capitalization ratio chosen by the Company places an excessive and undue emphasis on the higher return on equity at the expense of the lower cost of debt and can impute a capitalization ratio for ratemaking purposes if the evidence demonstrates a reduction would nevertheless be sufficient.

Q: Please explain the impact of the chosen capitalization ratio on UGI's requested overall revenue requirement.

A: UGI Gas Exhibit A, Schedule B-7 to the rate case presents various schedules that show that the impact of the chosen capitalization ratio at the Company's desired ROE of 10.75% and cost of debt of 5.17% is an overall rate or return of 8.2%. If the Commission were to impute a ratemaking capitalization ratio of 50% equity and 50% debt, the overall rate of return at the Company's desired ROE of 10.75% would be 7.97% as shown in Table 10, below:

Table 10 – Rate of Return at 50/50 Capitalization Ratio.[94]

Description	Capitalization Ratio	Cost	Return %
Long-Term Debt	50.00%	5.17%	2.59%
Common Equity	50.00%	10.75%	5.38%
Total	**100.00%**		**7.97%**

The effect of this reduction in overall Rate of Return from 8.2% to 7.97% in the overall revenue requirement is $17.4 million which is the difference between the $99.4 million sought by UGI in this case and the $82 million that would be required if the PUC were to

[94] Derived from UGI Gas Exhibit A – Fully Projected Future Test Year, Schedule B-7 changing capitalization ratio to 50/50. This reduces the overall needed change in revenues displayed on Schedule A-1 from $99.4 million to $82 million all other factors held constant. $99.4-$82 is $17.4 million annual reduction to revenue requirement.

impute a 50/50 capital structure.[95] This means that merely by re-weighing the capitalization ratio to have 50% of the return weighted at UGI's calculated cost of debt and 50% weighted at its requested ROE of 10.75%, the PUC could save ratepayers $17.4 million annually.

Q: Are you recommending that the Commission adopt a 50/50 capital structure?

A: Yes. The Commission should consider imposing a mitigated/imputed ratemaking capital structure. This is important for several reasons. First, as noted above, a 50/50 capital structure for ratemaking purposes would save $17.4 million annually in rates. Second, the Commission should consider the fact that UGI is not a publicly traded company, and its corporate parent is entirely in control of its capital structure and equity contributions. This matters because there are layers between UGI and the actual capital markets. This is the Commission's job as UGI's economic regulator: to ensure that as a monopolistic enterprise UGI is not taking undue and unfair advantage of its customers through its choice to skew its capital structure more favorably towards equity than its cost of debt. Given that even without any other changes to the case as presented by UGI, the Commission could shave $17.4 million from the requested revenue requirement simply by requiring UGI to use a 50/50 capital structure for ratemaking purposes, the Commission should seriously consider this in its setting of rates in this proceeding.

[95] Id.

Q: Please summarize your overall conclusions from this section of your testimony?

A: Based on the record evidence in this proceeding, the Commission should not increase UGI's rates. This conclusion is based on the totality of factors, including:

- The hardship that this rate increase would cause of UGI's customers is significant as outlined thoroughly in my testimony above.
- The fact that UGI appears to be sufficiently well capitalized earning a return that provides sufficient revenue for UGI to be able to provide safe and reliable service.
- Specifically, less than one month before UGI filed this rate increase, its calculated ROE was 10.43%[96]
- For each of the last 5 years, it has had actual ROEs that were never lower than 10.43% and were as high as 13.45%[97]
- Additionally, *at current rates*, UGI projects net income of more than $236 million in the current year ending September 30, 2026, and anticipates returning dividends of $60 million to its parent company.[98] This is in *addition to* the more than $249 million that it paid in dividends to its parent company since 2023.[99]

It is not readily believable that UGI's financial condition will deteriorate so rapidly between the end of the Future Test Year (September 30, 2026) when it projects $236 million in net income and dividends of $60 million to its parent that it requires rate relief in the amount requested in this case. While it *projects* that it will only earn 7.7% ROE as of the end of its FPFTY, the Commission should scrutinize this claim carefully given the above and, in my view, should reject UGI's rate increase request in its entirety.

If the Commission decides to allow a rate increase, it should carefully measure the amount of increase needed and follow the recommendations of the OCA regarding a recommended rate or return and should impute a capital structure for ratemaking

[96] See supra, Tables 8-9
[97] See Id.
[98] See UGI Filing Requirements, Book I, Attachment III-A-13.
[99] See supra, Table 6.

purposes that equally values equity and debt at 50%. These recommendations are meant to temper the excessive rates sought by UGI and more fairly balance the needs of UGI with its customers, particularly its low income customers.

V. Rate Design

Q: Please summarize UGI's proposed rate design for its residential customers.

A: UGI is seeking to continue collecting its total revenue allocated to residential customers by charging a fixed monthly customer charge and a volumetric charge. The increases are as follows:

Table 11: Proposed Rate Design and Increases

Description	Current Rate	Proposed Rate	Increase ($)	Increase (%)
Customer Charge (per month)	$16.25	$23.00	$6.75	41.5%
Distribution Charge (per Mcf)	$6.3317	$6.8383	$0.5066	8.0%

UGI is seeking to assess $74.7 million of its total increase of $99.4 million to residential customers. Of this amount, the increase to the fixed customer charge would generate $51.4 million additional dollars each year at proposed rates and the remaining $25.6 million would be collected through volumetric charges.[100] The total increase for the average residential customer using 68.7 ccf of gas each month would be $9.94 per month or 8.7% after accounting for the removal of the Distribution System Improvement Charge.[101] Over the course of the year, this increases the average customer's bill by $119.

[100] UGI Exhibit E, Proof of Revenues, page 2 of 7. The total amount of the increase equals $74.7 million after accounting for a reduction in certain riders and zeroing out of the DSIC.
[101] UGI Gas Statement No.1 at 8, Table 1.

In addition, UGI has proposed to continue its Weather Normalization Adjustment (WNA) rider[102] with modest adjustments. As explained more fully below, the WNA Rider is a charge applied to customers in the residential (R and RT) and small business rate classes (N and NT) for bills rendered during the 7-month period from October to April. This charge was approved first in UGI's 2021 rate case and first went into effect on November 1, 2022. The net result is not positive for customers. As discussed more fully below and shown in Table 12, residential customers paid more than $44.2 million in WNA charges since November 2022.

Q: Do you have concerns about UGI's proposed rate design?

A: Yes. I have several concerns about UGI's proposed increase to its fixed customer charge and its decision to maintain its WNA. In short, these proposals are geared towards shifting risk of UGI under collecting its revenue requirement from UGI's shareholders to its customers because they work together to lock in revenue for UGI at the expense of customers and irrespective of whether a customer can or cannot afford service.

Q: Please explain what you mean when you say that the fixed customer charge and WNA rider work to lock in revenue for UGI.

A: The combination of an increased customer charge and the WNA together work to ensure that UGI is insulated from the risks associated with the fact that they are in the business of providing a commodity that a consumer may use less of in a given year – whether that usage reduction is driven by externalities like weather, the adoption of efficiency measures, the installation of electric appliances or supplemental heating equipment, or careful conservation. In general, residential customers use the most gas

[102] Book XI, UGI Utilities, Inc.-Gas Division Tariff, Supplement No. 63 to UGI Gas – Pa. P.U.C. No. 7, Fifth Revised page No. 53. ("Proposed WNA Rider").

service in the winter to serve their winter heating load. If more of a customer's bill is fixed each month through the fixed monthly charge, then less of it is dependent on how much gas they use. On the other side, if the weather sensitive volumetric usage is surcharged through a WNA for 60% of each the year (October – April), then UGI is made whole when the weather is warmer than the historical average. Together, UGI's proposed high fixed charge and WNA create a double penalty for customers because they either pay a higher fixed customer charge regardless of usage or they bear more of the risk of a warmer winter. Both are problematic for low income customers who struggle each month to be able to afford to retain gas service.

A. Monthly Customer Charge

Q: Please discuss your concerns about UGI's proposal to increase its monthly customer charge for residential customers from $16.25 per month to $23 per month as it relates to low income households.

A: The proposed increase in the fixed monthly customer charge weakens the ability of low income households to save money on their bills each month because less of their bill is dependent on the volume of gas they consume. The proposed fixed customer charge will result in an increase of $81 per year, an amount which will be unavoidable for low income households struggling to maintain service and will exacerbate an acute affordability crisis.

Q: UGI witness Taylor asserts that the increase would benefit low income customers. Please explain his rationale.

A: Mr. Taylor asserts that this increase would benefit low income customers who tend to have higher than average use.[103] Mr. Taylor also asserts that placing more of the overall revenue requirement collection into volumetric charges harms low income customers because it requires them to have to make decisions to reduce their gas usage that may impact their quality of life.[104] He further states that he conducted an analysis that shows, based on the Company's requested revenue requirement, that an average UGI non-CAP low income customer with a usage of 86.7 Mcf/year would save $7.18 per year, or 0.8% of their annual bill, if the fixed customer charge is increased to $23 per month than if it remains at $16.25 per month.[105]

Q: Do you agree with Mr. Taylor's analysis?

A: I agree with his math and that at 86.7 Mcf/year at UGI's proposed revenue requirement, a customer would make out marginally better (~$7/year) at a $23 monthly customer charge and a volumetric rate of $6.8383/Mcf as compared to a $16.25 fixed customer charge and a volumetric rate of $7.8558/Mcf. The breakeven point appears to be usage of about 78.6 Mcf/year. If you use more than that amount, you will benefit from UGI's proposal. But if you use less than that, you will pay more under UGI's proposal. The use of averages by their very nature fails to accurately reflect the range of consumption patterns of customers. All customers have factors that influence how much or how little they use or do not use, including things like how many people live in the house, the size

[103] UGI Statement No 10 at 28-29.
[104] Id. at 29.
[105] Id. at 31, Table 7. Although Table 7 is labeled "Average CAP Customer" annual charges, the text of Mr. Taylor's testimony and the data make it clear that he uses the average usage of non-CAP CLI customers.

of the residence, the efficiency of the heating equipment, whether the customer's home is air sealed or whether it is drafty.

Q: Would UGI's proposed increase to the fixed charge affect the Company's Low Income Usage Reduction Program (LIURP)?

A: It could. UGI's proposal undermines the explicit goals of LIURP to "reduce residential energy bills." [106] By reducing the amount of bill reduction that can be obtained through LIURP measures, the proposed increase to the fixed charge threatens the continued effectiveness of ratepayer investments intended to reduce energy consumption, delinquencies, collections, and uncollectible costs. Thus, the proposed increase to the fixed charge will, in turn, impact the ability of LIURP to "decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs."[107] This would produce an unreasonable result. LIURP is a statutorily mandated program to be provided by the Companies to help low income customers reduce or manage their energy consumption in a cost-effective manner. Any increase to the fixed charge would both undermine the goal of LIURP and make the existing program less cost effective.

The ability to save money through energy efficiency is tied directly to a bill structure that bases costs on throughput. But as more residential customer costs are shifted to the fixed charge, the achievable bill savings – and the corresponding impact on bill payment

[106] 52 Pa. Code § 58.1 ("The programs are intended to assist low-income customers conserve energy and reduce residential energy bills. The reduction in energy bills should decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs.").
[107] Id.

behavior – will erode. The ability to achieve bill savings through energy efficiency and conservation measures is especially important for households with income above 150% but less than 200% of poverty who are ineligible for CAP or LIHEAP but are eligible for energy efficiency and conservation services through LIURP or the federal Weatherization Assistance Program (WAP) – both of which have income guidelines of up to 200% of the Federal Poverty Level (FPL).[108] These households need to retain the ability to reduce their monthly energy costs through adoption of comprehensive energy efficiency and conservation programming.

Given that low income households are disproportionately at risk of termination and often lack the ability to control usage due to poor housing stock and older, less efficient appliances,[109] it is critical that they continue to have access to effective conservation tools capable of producing meaningful and lasting bill reductions.

Q: Mr. Taylor also asserts that fixed monthly charges allow for greater predictability in household budgets and, thus, are preferable because low income households have less ability to control their usage[110] Do you agree with Mr. Taylor?

A: I agree with Mr. Taylor that many low income households take steps to reduce usage that are better characterized as deprivation of essential services rather than truly

[108] While generally available only to customers up to 150% of poverty, up to 20% of LIURP participants may have household income up to 200% of poverty on a first come, first served basis. See UGI Universal Service & Energy Conservation Plan for the Five Year Period January 1, 2020 – December 31, 2025 at 34 (Weatherization Program Eligibility). Available at: https://www.puc.pa.gov/media/2953/usecp_ugi_electric-gas_revised030424.pdf (Last visited April 10, 2026).

[109] See, Nat'l Energy Assistance Directors' Ass'n (NEADA), Energy Hardship Report at 16 (Aug. 2024) (finding that low income consumers are more likely to live in housing with poor quality insulation or no insulation at all), https://neada.org/wp-content/uploads/2024/08/August-Summer-Hardship-Report-Final.pdf (Last visited April 10, 2026).and, Hernandez, Diana, Energy Insecurity and Health: America's Hidden Hardship, Health Affairs Health Policy Brief, June 29, 2023 (finding that energy insecurity is rooted in the interconnection of poverty and housing deficiencies), available at: https://www.healthaffairs.org/content/briefs/energy-insecurity-and-health-america-s-hidden-hardship-1773887489273 (Last visited April 10, 2026).

[110] UGI Statement No. 11 at 29-30.

conservation of energy. These households do so out of necessity and poverty. As outlined more fully in my testimony above, acute energy unaffordability has a profound impact on families – causing many to forego food, medicine, and other necessities to maintain energy services to their home. However, I disagree with Mr. Taylor that the solution to this problem is to increase the fixed customer charge for these households. Additional funds for energy efficiency and weatherization, easier access for tenants to take and receive full cost LIURP services, and improvements in access to CAP are far better tools to assist low income customers and allow them to avoid the consequences of energy deprivation than a rate design that locks in more of their monthly costs regardless of usage. Wresting control from customers to reduce their bill through reducing their usage does not benefit low income customers, it weakens their ability to maintain access to service.

Finally, regarding Mr. Taylor's assertion that a fixed bill provides a more stable and predictable bill each month, I would submit that a bill that is stable but unaffordable is meaningless for low income customers. While bill stability is a helpful tool for customers, enrollment in CAP which provides a bill based on a customer's ability to pay is far more useful to create actual bill stability from one month to the next than a higher fixed customer charge. Furthermore, UGI is legally required to offer the option of budget billing which is meant to produce bill stability without decreasing incentives for conservation and energy efficiency.

Q: Should UGI's fixed customer charge be increased?

A: No. UGI's fixed monthly customer charges should not be increased because I do not recommend an increase in the revenue requirement, and I recommend that the WNA end with the current pilot. These recommendations are inextricably entwined. If the

Commission awards any increase and if the Commission allows UGI to retain its WNA, then I would do not oppose an increase in the monthly customer charge that is proportionately scaled back from the proposed $23 to any revenue requirement authorized in this case.

Q: Why does your recommendation about the customer charge depend on whether the Commission eliminates UGI's WNA?

A: To be clear, the outcome dictated by the evidence and my analysis is that UGI should not receive any increase, the customer charge should remain $16.25, and the WNA should be eliminated. This combination places risk of under-collection on UGI who is in the best position of all entities to manage that risk and produces the most favorable opportunity for low income customers to reduce their bills each month by reducing their usage. However, if the Commission decides to allow UGI to retain its WNA despite its impacts on customers, then a higher volumetric charge (all other things being equal) will produce a higher WNA charge in the months a WNA is assessed because it is based on the volumetric charge. Thus, my secondary recommendation is that to the extent the Commission allows UGI to retain its WNA, then a modest increase in the monthly customer charge would mitigate against the continued impact of the WNA.

B. Weather Normalization Adjustment

Q: What is UGI proposing regarding its WNA rider?

A: Under the terms of UGI's current tariff, the Company's 5-year WNA pilot will end on October 31, 2027, unless affirmatively extended or otherwise permitted by

Commission order.[111] UGI proposes to continue the WNA as a pilot for an additional 5 years, through October 31, 2032, with the modification that the charge be calculated using a 10-year average of heating degree days that will be updated at each rate case.[112]

Q: Please explain UGI's WNA.

A: UGI's WNA is a charge that currently UGI applies to residential and small business customers bills each month from October to April to account for whether the temperature for the month was warmer than normal or colder than normal. Here is an explanation of how the WNA will work based on the Company's proposal:[113]

- UGI calculates normal weather based on a concept known as a heating degree day (HDD). An HDD is the number of degrees below 65 degrees Fahrenheit. In other words, 10 HDD would mean that on a given day the average measured temperature was 55 degrees Fahrenheit. UGI calculates the number of "normal" HDDs for each day of the year based on the 10-year average number of HDDs in the delivery region. UGI has three delivery regions.
- The WNA assumes that the weather in the future – when bills are charged – will reasonably approximate this 10 year daily average HDDs. That is, the WNA is set based on the presumption that UGI should be permitted to collect normalized revenue produced by normalized temperatures rather than the revenue associated with the actual temperatures at the time service is delivered.
- In the 7 months of October through April, UGI calculates what it calls a customer's weather normalized billing Ccfs (WNBC). This is the amount that the customer ***would have used*** if weather had conformed to the "normal" pattern (e.g., the average weather over the past 10 years) and there were the same number of HDDs for the billing period. This WNBC is adjusted to account for a 3% cushion of HDDs on either side of normal – often referred to as a 'dead band'.[114]

[111] See Book X, UGI Exhibit F, Current Tariff, Supplement No. 59 to UGI Gas – Pa P.U.C. No 7, Fourth Revised Page No. 53.
[112]UGI Statement No. 11 at 33-34.
[113] Book XI, UGI Gas Exhibit F – Proposed Tariff, UGI Utilities, Inc.-Gas Division Tariff, Supplement No. 63 to UGI Gas – Pa. P.U.C. No. 7, Fifth Revised Page 53 No. 53. ("WNA Rider").
[114] See id. at (g) ("A deadband of 3% shall apply. The WNA for a billing cycle will apply only of the [Actual HDD] for the billing cycle are lower than 97% of higher than 103% of the [Normal HDD] for the billing cycle.")

- UGI subtracts from the WNBC the usage that it considers to be baseload monthly Ccfs (BLMC), which is calculated from the customer's usage in the summer months. UGI asserts that this calculation allows it to isolate application of the WNA to apply to a customer's weather sensitive usage.
- During the WNA months of October through April, UGI calculates a customer's actual monthly Ccfs (AMC), which is their actual metered usage.
- To determine the WNA, UGI then subtracts the weather normalized bills Ccfs (WNBC) (i.e., what they should have used under "normal weather") from the actual monthly Ccfs (AMC) less their baseload monthly Ccfs (BLMC) to arrive at their Weather Normalized Adjustment Ccfs (WNAC).
- The WNAC is then multiplied by the applicable distribution charge for the rate class to determine the WNA amount that is applied to the bill.
- These are the amounts, in aggregate, that are reflected in Table 12, above and have resulted in $53.5 million in net WNA charges over the period from November 2022 through January 2026.

In simplified terms, the WNA is a charge applied to residential and small business customers' bills not based on what they use but based on what they *would have used* had the weather been outside of 97% - 103% of the "normal" weather, as calculated by UGI's tariff reflected in HDDs. When the weather is warmer than 103% of normal as reflected in HDDs, UGI charges customers for service they <u>did not use</u> but that they would have used had the temperature been "normal" per UGI's calculation. When the weather is colder than 97% of normal as reflected in HDDs, it credits them for service that they <u>did use</u> but would not have used had the temperature been "normal" per UGI's calculation.

Q: What are your concerns about the WNA?

A: I have several concerns that I list here and outline more fully below:

- The WNA shifts weather related risk from the utility to customers in a way that is inappropriate for a monopoly provider of essential services because the WNA improperly assumes that UGI is entitled to revenue based on weather as it existed in the past rather than as it exists as the time service is delivered.

- The WNA requires an overly complicated and nuanced calculation that is difficult for customers to understand because it charges customers not for their actual usage but their hypothetical usage.
- While mathematically bi-directional, in practice, the WNA more often works to the detriment of customers and the benefit of UGI as it results in millions of dollars of additional charges each year that customers pay for service they did not use.
- The WNA charge inflates other riders collected by UGI including its DSIC.

Q: Please explain why the WNA shifts weather related risk from the utility to customers in a way that is inappropriate for a monopoly provider of essential services?

A: The WNA shifts weather-related risk from the utility to customers by assuming that UGI is entitled to revenue based on its calculation of normalized weather as opposed to actual weather at the time that it bills a customer. This is problematic from a consumer's perspective. The very nature of gas distribution service is that it exists to deliver a commodity that is weather dependent. Residential customers would likely not pay for *an entire gas distribution system* simply to only cook, heat water, or have fireplaces, as it would be too expensive for the system to exist solely for that purpose. We have these systems because it produces heat in winter months, these other uses are ancillary. In my view, it is inappropriate for a monopoly provider of essential utility service that is inherently weather dependent to shift weather-related risk to consumers. As a monopoly, the utility has no competition and is guaranteed a customer base. As such, the Commission needs to exercise the appropriate level of competitive restraint on the kinds of charges that it allows companies like UGI to assess.

Q: Is UGI better able to shoulder the risk of revenue fluctuations created by warming weather?

A: Yes. As outlined by above, low income customers do not have any margin month in and month out to spend more on energy costs. In winter months that are warmer than normal, these customers are expecting a lower bill not a weather adjusted bill. In contrast, utilities like UGI benefit from regulatory frameworks that allow them to recover costs and earn a reasonable return on their investments from captive ratepayers. In this case, UGI is projecting its revenue needs based on a fully projected future test year and is allowed to establish a revenue requirement based on its projections of the world as it expects it to be as of September 30, 2027. UGI also will be permitted to charge a DSIC after September 20, 2027, of up to 5% of billed revenue for necessary infrastructure upgrades and operational expenses. Both built-in alternative rate mechanisms offer the kinds of financial protection to UGI that customers simply do not have and allow UGI to be better positioned to absorb the effects of variable weather conditions without passing these risks down to consumers. Instead of offloading the risk to ratepayers, it would be more appropriate for the utility to manage the risk.

Q: Do you have other concerns about the WNA?

A: Yes, the WNA requires an overly complicated and nuanced calculation that is difficult for customers to understand because it charges customers not for their actual usage but for their hypothetical usage. It is not reasonable to assume that customers understand the WNA or why it is in place. While UGI recently revised its WNA scripting to improve the information that it provides, the concept that one must pay for usage that UGI anticipates that they would use under normal weather rather than what you did use under

actual weather is a difficult concept to understand. Most people expect to be billed for what they use, not what the utility calculates that they should have used had the weather been an average winter.

Q: You mentioned above that the existence of credits when weather is colder than normal. Is this a benefit to customers?

A: Yes, but it is not worth the tradeoff because it happens so inconsistently. I do not dispute that under the WNA formula when weather is colder than normal customers get a bill credit that they would not otherwise have received in the absence of the WNA charge. The problem is that this rarely happens. The WNA has been in effect since November 2022. In the months between November 2022 through February 2026, there have only been 6 months (January-February 2025 and November 2025-February 2026) in which the WNA was assessed where customers in aggregate were provided with credits. The remaining months, customers were charged. On net, the WNA has simply not been positive for customers.

Table 12 – Net WNA Charge to R and RT Customers[115]

Year	WNA Revenue
2022	$1,797,324.60
2023	$24,315,727.00
2024	$30,472,835.86
2025	$1,766,165.42
Jan. 2026	($3,857,593.80)
Feb. 2026	($10,281,879.00)
Total	**$44,212,580.08**

As shown above, the WNA has surcharged customers a total of $44.2 million based on what UGI calculated they should have used had the weather conformed to normal. While

[115] WNA Calculation derived from UGI Response to OCA 7-2, Attachment and 8-50, Attachment. Attached hereto at Appendix B.

this winter was significantly colder than normal and customers saw significant credits in aggregate in early 2026, this comes after several years of paying more each winter because of significantly warmer weather than normal. I submit that customers would overall find it of little value that they can receive a credit in months that are colder than normal because, based on the history, while it happened recently, it does not appear that these months occur with any regularity.

Q: Doesn't the fact that the WNA credits some months and charges others mean that it's working how UGI intended it?

A: Yes. The WNA is working exactly like UGI intended to it to work: It collects substantial net revenue from customers precisely because, over the long term, winters are warmer and they are projected to continue to warm.[116] There is no real debate about the direction that our weather is headed long term given the impacts of climate change. It is warming overall significantly and, thus, the WNA is far more likely to produce significant asymmetry and surcharge customers on net each year than it is that customers will see net credits.[117] Thus, it is no accident that the WNA shows very few months where there is a bill credit. I doubt very much that UGI would have proposed a WNA if it did not work to its financial benefit. In fact, shortly after this case was filed, UGI Utilities, Inc. – Electric division filed a rate case.[118] These companies are owned by the same corporate parent; however, UGI Electric did not file a reciprocal adjustment mechanism to account

[116] See Pennsylvania Department of Environmental Protection, Pennsylvania Climate Impacts Assessment 2024 at 18 (finding that Pennsylvania's annual total heating degree days are anticipated to decrease by 13% by mid-century and 25% by end-of-century compared to the historical baseline). Available for download at: https://www.pa.gov/agencies/dep/residents/climate-change/impacts.html (Last visited March 30, 2026).
[117] See id.
[118] UGI Utilities, Inc. – Electric Division PA P.U.C. No. 6, Supplement No. 92, Docket No. R-2025-3059430 (Filed Mar. 27, 2026).

for weather sensitive electric usage (i.e., air conditioning usage in the summer) that would credit customers for warmer than normal summer temperatures and more cooling degree days than a 10 year normal.

Q: Do you have other concerns about the WNA?

A: Yes, UGI's DSIC charge is also assessed on the WNA rider which means that UGI receives DSIC revenue based not only on the revenue charged based on a customer's usage but also based on what UGI calculated that the customer should have used had the weather been "normal." This compounds the irrationality of the WNA because it charges a surcharge on a surcharge, which works to increase UGI's billed revenue at the expense of its customers.

Q: Does UGI appear to need the WNA charge to generate sufficient overall revenue?

A: No, not in my judgment. There are a few factors upon which I base this determination. First, UGI admitted in response to discovery that the WNA has no bearing on whether it can provide safe and reliable service, instead it is about whether it can meet its authorized revenue requirement.[119] Thus, there is no basis in the record to conclude that the WNA is necessary for the safety or reliability of UGI's service to customers, which would include its compliance with its long term infrastructure improvement plan (LTIIP) and any other capital replacement and improvement plan that is about the safe and efficient operation of its system. As such, I am left to conclude that more revenue is not at all driven by the operational needs of the system. Instead, the WNA is all about whether UGI can maximize its revenue for the benefit of its shareholders.

[119] UGI Response to CAUSE-PA 4-7, Attached hereto at Appendix B.

Second, with the WNA in place, UGI loses a significant incentive to operate efficiently. As noted at the beginning of my testimony, under the framework of traditional ratemaking, once rates are set the utility can earn at or above its authorized revenue requirement through operating efficiencies that generate fewer expenses than projected leading to higher retained earnings. With the WNA in place, there is one less variable for the Company to concern itself with and UGI hits its projected revenue targets for the end of the fully projected future test year regardless of the efficiency of its operations. While UGI may see this as a net positive, in my view, because it works to discourage efficient operations, the WNA effectively works as a wealth transfer from UGI's customers to UGI's shareholders for services that were not used by UGI customers.

Q: UGI is changing its definition of normal weather to a 10-year normalization period that it proposes to adjust at each rate case. Does this change alleviate any of your concerns?

A: No. While I support this change if the WNA is to continue as it will more closely align normal weather for establishing rates in a rate case with normal weather under the WNA, it does not alleviate the underlying uncertainty associated with billing based on normalized weather rather than actual weather. Although I anticipate under this change the WNA charges and credits will be lower, my objection to the WNA is that is shifts the risk of under collection from the utility where it belongs to its far less sophisticated customers – many of whom simply cannot bear this risk financially.

Q: Mr. Taylor asserts that its WNA is just and reasonable based on the factors outlined in the Commission's policy statement related to alternative ratemaking mechanisms at 52 Pa. Code § 69.3302. Do you agree?

A: Mr. Taylor outlines his responses to each of these factors in his exhibit JDT-4. I have responded to each of Mr. Taylor's assertions in Appendix C, Cicero Exhibit C-3.

Q: What is your overall conclusion about whether the WNA should continue?

A: I recommend that the Commission reject UGI's request to continue its WNA and that the WNA cease, effective October 31, 2027, as is set out in its current tariff. UGI's WNA is designed to stabilize UGI's revenue fluctuations caused by variations in weather, but it does so by disproportionately burdening low income customers, raising deep concerns about fairness and equity. While this mechanism protects UGI from revenue volatility, it transfers the financial risk of warmer weather onto customers who may have already reduced their consumption to manage tight household budgets. For low income households, which often face difficult choices between heating, food, and other essentials, these additional charges undermine their ability to plan for and manage utility expenses effectively.

Additionally, the timing and unpredictability of WNA-related charges exacerbate the financial stress experienced by low income customers. Because the WNA is applied retrospectively to account for weather variations, customers may face unexpected bill increases that are difficult to predict or budget for. These charges are also assessed in the months with the highest bills thereby compounding monthly bill unaffordability. This unpredictability is particularly harmful to low income households, where any deviation in monthly expenses can disrupt financial stability. The WNA introduces a variable that

makes it more challenging for vulnerable households to manage their limited resources effectively.

Q: If UGI is permitted to continue the WNA, should it be reformed?

A: Yes. While my primary recommendation is that the WNA should be eliminated at the conclusion of the current pilot, if the WNA is not eliminated it should be significantly reformed in the following ways.

First, UGI's proposal to change its WNA to normalized 10-year period that it updates at each rate case should be accepted. As noted above, this is better than the status quo and will more readily conform normalized weather to actual weather.

Second, the WNA should remain a pilot but should be approved for a period of no more than 3 years rather than 5 years so that its effectiveness can be assessed more frequently.

Third, the months in which the WNA is operable should be reduced to the period from December through March, as these are the winter months recognized by the Commission and the General Assembly for other public policy purposes such as the winter termination rules that prevent termination of service to households with income at or below 250% FPL. If these are the months when economically vulnerable households must retain service because of the possibility of cold weather, it is unreasonable to allow UGI to assess a weather-related charge in the months of October, November, April, or May. At the very least, the month of October should be eliminated to be consistent with the Commission's most recent decision in the Columbia Gas 2025 rate case where it approved Columbia's WNA only for the months November through April.[120]

[120] Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2024-3067174, Final order at 202 (Dec. 4, 2025).

Fourth, WNA billed revenue should be excluded from the revenue upon which the DSIC is assessed. In my view, UGI should not be allowed to assess an up to 5% surcharge on top of the WNA surcharge. It compounds the harm to households for whom the WNA is assessed and inflates the revenue that UGI collects through its DSIC.

Fifth, the deadband should be increased to 5% rather than the current 3%. This would bring the WNA in alignment with that which was recently permitted to continue in the Columbia Gas 2025 rate case and would produce fewer months where the WNA would be charged or credited and allow for actual significant deviations in weather to be adequately addressed.

Finally, to promote revenue stability, the WNA should be applied on a per class basis, reconciled annually, and surcharged over the full 12-months of the subsequent year rather than on a per customer basis. This change would eliminate the hardship that currently exists by imposing WNA charges during the highest usage and most expensive bills in the winter where energy burdens are at their highest.

Q: Please explain more fully your last recommendation.

A: The WNA is designed to collect revenue on a per class basis measured against an aggregate number of heating degree days using a 10-year time frame, but UGI currently assesses it on a per customer basis and does so immediately as the charges are incurred. This means that if December is warmer than normal by 5 HDDs UGI will impose a WNA charge in January to account for this 5 HDD difference. If in January, the weather is colder by 5 HDDs, they will apply a credit in February for this difference. While these net out, I am concerned about the impact the WNA has on low income households' monthly ability to afford service as they already face significant bills in the winter and have energy

burdens that are as high as 16% during these months. My alternative proposal would have UGI accrue as a regulatory asset all WNA charges and credits during the winter months on a per class basis. At the end of the WNA period (March or April depending on whether the Commission accepts my recommendation to narrow the WNA months for December – March), UGI would allocate the residential class wide net WNA charge across all residential customers on a per ccf basis to all residential non-CAP customers over the subsequent 12-month period. Spreading the WNA out over a 12-month timeframe on a class wide basis would, at least partially, address my concerns about higher charges occurring during the winter months. It would also be a more effective means of reducing the impact of the WNA on a month-to-month basis and balancing the adjustments over a longer timeframe.

VI. Universal Service and Energy Conservation Programs

Q: What are universal service and energy conservation programs?

A: In short, universal service and energy conservation programs are inclusive of those programs, policies, and procedures which help ensure low income households stay connected to service and reduce their usage.[121]

Q: Please briefly describe UGI's universal service and energy conservation programs.

A: UGI operates four Universal Service and Energy Conservation programs that assist low income customers: (1) the Customer Assistance Program (CAP); (2) the

[121] 66 Pa. C.S. § 2203.

Hardship Fund (Operation Share); (3) the Low Income Usage Reduction Program (LIURP); and (4) the Customer Assistance Referral and Evaluation Services (CARES).[122]

As a threshold matter, I note that on April 1, 2025, UGI filed its proposed Universal Service and Energy Conservation Plan for 2026-2030 (Proposed 2026 USECP), which remains pending before the Commission.[123] I also note that in the Settlement of its most recent rate case, UGI made several commitments related to its Universal Service and Energy Conservation programs that it is still in the process of implementing.[124] I am not seeking to disrupt those processes, but have several additional recommendations that are not accounted for by either its pending USECP or its prior rate case settlements.

Q: Is UGI proposing any substantive changes to its Universal Service and Energy Conservation Programs in the context of the present proceeding?

A: No.

Q: Please explain how this section of your testimony is organized.

A: I will assess and offer recommendations related to UGI's universal service programs. I will also assess and offer recommendations related to UGI's overall policies and processes for universal service program outreach and enrollment.

A. Customer Assistance Program (CAP)

Q: Please briefly describe UGI's CAP.

A: UGI's CAP provides discounted monthly bills and arrearage forgiveness to low income customers at or below 150% FPL. UGI's CAP rates are calculated each month

[122] 2020-2025 USECP at 1-2.
[123] UGI Utilities, Inc. - Gas Division and UGI Utilities, Inc. - Electric Division Universal Service and Energy Conservation Plan for 2026-2030, Docket No. M-2025-3054362 and M-2025-3054366. (Proposed 2026-2030 USECP)
[124] Pa. PUC v. UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716, et al., Joint Petition for Settlement of All Issues (Submitted July 9, 2025).

based on the lower of a percentage of customer's monthly income (Percentage of Income Payment (PIP) amount), or a CAP participant's average monthly bill.[125] For gas heating customers, maximum monthly CAP payments are set at 4% for customers with household incomes between 0-50% FPL, and 6% for customers with household incomes between 51-150% FPL.[126] CAP participants with no income are responsible for making a minimum monthly CAP payment, which is set at $25 for gas heating customers and $15 for non-heating customers.[127]

Q: How many customers are enrolled in UGI's CAP?

A: As of January 2026, UGI reports that 26,250 customers were enrolled in its CAP.[128] As of August 2025, UGI witness Brian Meilinger reports that UGI serves 143,404 estimated low income customers.[129] Thus, in January 2026, 117,154 estimated low income customers – or 82% – were not enrolled in CAP.

Q: Do you have concerns about the number of low income customers not enrolled in UGI's CAP?

A: Yes. CAP is a critically important affordability program, helps to reduce low income termination rates and arrearage levels of participants. However, most customers eligible for CAP assistance are not enrolled, limiting the ability of CAP to mitigate unaffordability for its broader low income customer population at proposed and present rates. This under enrollment is especially concerning in the face of UGI's proposed rate increase, the effects of which will fall hardest on low income households who are not enrolled in CAP.

[125] 2020-2025 USECP at 22.
[126] 2020-2025 USECP. at 23.
[127] 2020-2025 USECP. at 24.
[128] UGI Response to CAUSE-PA 1-6, Attachment. Attached hereto at Appendix B.
[129] UGI Statement No.12 at 16.

Q: Has UGI made efforts to improve its CAP enrollment?

A: Yes. In his testimony, UGI witness Brian Meilinger indicates that UGI's average CAP enrollment for 2025 was 25,346 customers, representing a 3% increase over 2024, and a 26% increase over 2022 CAP average enrollment of 20,134.[130] He addresses efforts that UGI has undertaken to increase CAP enrollment.[131] He indicates that the Company undertook a project to assess, identify, and engage with low income customers in 2023-2024, and that UGI's Low Income Customer Assessment and Outreach Pilot utilized Experian to help identify potential low income customers and performed targeted marketing via email and direct mail.[132] Mr. Meilinger indicates that UGI will continue its general outreach efforts, as well as a twice a year personalized outreach via email and direct mail to customers who are self certified low income and to LIHEAP recipients that are not currently enrolled in CAP. UGI is also undertaking expanded outreach efforts through additional in person Winter Assistance Relief Mobilization ("WARM") events held at targeted locations each year.[133] UGI also has been participating in the DHS data sharing process conducting outreach to data sharing participants who have not yet enrolled in CAP, and utilizing the data sharing file to recertify customers for CAP.[134]

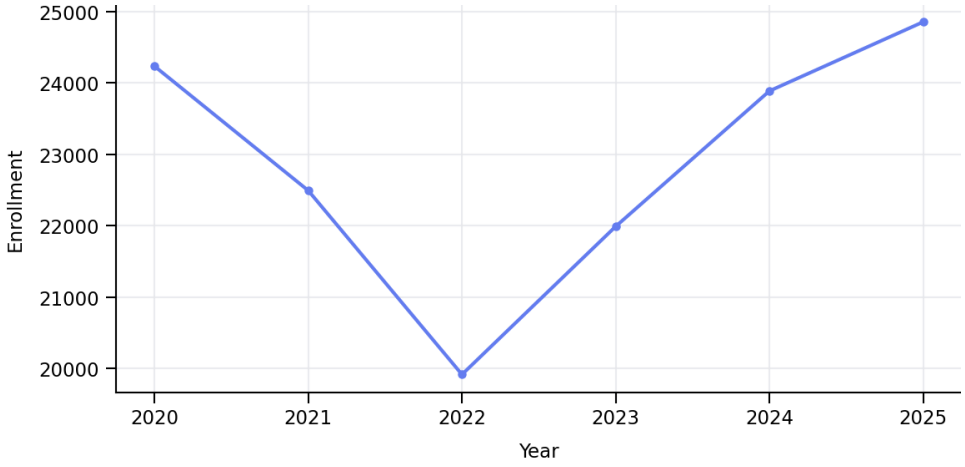
Q: Are UGI's initiatives adequate to address the undersubscription of its CAP program?

A: No. While I appreciate that UGI has made efforts to improve its CAP enrollment in recent years, it is important to consider the longer term trend. UGI witness Brian Meilinger

[130] UGI Statement No.12 at 5.
[131] UGI Statement No.12 at 6.
[132] UGI Statement No.12 at 6.
[133] UGI Statement No.12 at 12.
[134] UGI Statement No.12 at 13.

argues that UGI's average CAP enrollment for 2025 was 25,346 customers, representing a 3% increase over 2024, and a 26% increase over 2022 CAP average enrollment of 20,134.[135] However, he fails to acknowledge that UGI's CAP enrollment dropped off dramatically between 2020 and 2022; thus, the improvement from 2022 to 2024 essentially returned UGI's CAP enrollment to its prior levels – when its rates, and the corresponding need for rate assistance, were substantially lower than they are now. The following chart shows UGI's CAP enrollment since 2020:

Chart 3 UGI CAP enrollment 2020-2025[136]



While I acknowledge that enrollment has continued to increase in the past few years, it remains troubling that a large majority of UGI's estimated low income customers (82%) and a majority of UGI's reported confirmed low income customers (62%) remain

[135] UGI Statement No.12 at 5.
[136] 2023-2025 average CAP enrollment was derived from UGI's response to CAUSE-PA 1-6 Attachment. 2020-2022 CAP enrollment is reported in [136] Pa. PUC Bureau of Consumer Services, Report on Universal Service Programs & Collections Performance (2020), at p. 58 (Published Nov. 2021); Pa. PUC Bureau of Consumer Services, Report on Universal Service Programs & Collections Performance (2021), at p. 60 (Published Dec. 2022); Pa. PUC Bureau of Consumer Services, Report on Universal Service Programs & Collections Performance (2022), at p. 59 (Published Sep. 2023); available at: https://www.puc.pa.gov/filing-resources/reports/universal-service-programs-and-collections-performance-reports/

unenrolled in CAP.[137] These non-CAP low income customers will be disproportionately impacted by any rate increase approved in this proceeding as they will be forced to shoulder the full impact of any rate increase on top of their already unaffordable energy burdens.

Q: Do you have recommendations to improve UGI's CAP enrollment?

A: Yes. I recommend a more systematic and comprehensive approach to identifying eligible customers and enrolling them in CAP. To that end, the Commission should require UGI to implement routine screening of its applicants and customers to determine eligibility for CAP and other universal service programs.

While I am supportive of UGI's ongoing outreach efforts to connect customers with assistance, it is imperative that increased efforts are made to routinely and proactively connect customers with assistance before payment difficulties occur. Improving the identification of UGI's low income customers – and better matching these customers to critical rate assistance and usage reduction services at the earliest opportunity – is essential to providing just and reasonable rates and service to low income households, and to ensuring all consumers, including those eligible for CAP, are receiving the most advantageous available rate. Proactive CAP enrollment strategies, such as routine screening, also serves as a critical collections and cost containment tool – helping to reduce the accrual of unmanageable debts, reduce uncollectible expenses and other collections costs, and reduce the cost of the CAP arrearage management program.

[137] UGI Response to CAUSE-PA 1-6, Attachment (68,289 confirmed low income customers as of Jan. 2026); UGI Response to CAUSE-PA 1-6, Attachment (26,250 CAP customers as of Jan. 2026). Attached hereto at Appendix B.

To more accurately identify CAP eligible customers and enroll these customers in available assistance, I recommend that UGI be required to:

- Screen all new and moving customers for income level at the time their service is established and ask whether they would like information about income qualified programs that may reduce their rate.
- Screen existing customers for household income level on any non-emergency calls and inquire whether there have been any updates to household income information.
- Develop a process for routine income screening through UGI's online account portal.

Customers identified as low income through these regular screening processes should be referred for enrollment in CAP and other universal service programs – as well as LIHEAP. While UGI customers should be able to opt out of providing household income information, they should first be informed that if they choose to disclose this information, they may be eligible for lower rates or energy efficiency measures. I recommend that UGI develop and implement screening and referral recommendations within 90 days of the final order in this proceeding.

Q: Do you have recommendations about UGI's Universal Service Outreach in general?

A: Yes. I understand that, pursuant to the agreement in last year's UGI rate case, UGI is undertaking expanded outreach efforts in 2026 through additional in person WARM events held at targeted locations each year.[138] I also understand that each year thereafter, the Company will target a minimum of three new cities within its service territory as set forth in its tariff, which will be identified in consultation with its Universal Service Advisory

[138] UGI Statement No.12 at 12.

Committee.[139] I believe it is appropriate to utilize some of the geographic data provided by UGI in this proceeding to help inform the targeting of future outreach events, such as the WARM events. In response to discovery, UGI provided breakdowns of their confirmed low income customers and CAP customers by Zip code.[140]

According to this data, a majority (22,929 out of 41,697) of UGI's confirmed low income customers not enrolled in CAP are in 10 urban centers. The areas with the most confirmed are primarily in the following urban centers:

Table 13: UGI Service Territory
Areas with the Most Confirmed Low Income Customers Not Enrolled in CAP[141]

Area (Zip Codes)	**Number of Non-CAP CLI Customers**
Reading[142] (19601, 19602, 19604, 19605, 19606, 19607)	3,908
Wilkes Barre (18701, 18702, 18704, 18705, 18706)	3,666
Scranton (18504, 18505, 18507, 18508, 18509, 18510, 18512)	3,019
Allentown[143] (18101, 18102, 18103, 18104, 18106, 18109)	2,910
Harrisburg[144] (17101, 17102, 17103, 17104, 17110, 17111)	2,461
Lancaster (17601, 17602, 17603)	2,178
Bethlehem (18015, 18017, 18018)	1,506
Easton (18042, 18045, 18040)	1,181
Hazelton (18201, 18202)	1,343
Williamsport (17701)	1,025
Total	**23,197**

These areas all ranked among the highest in volume of low income service terminations.[145] These areas represent effective locations for targeted outreach and enrollment efforts for the Customer Assistance Program.

[139] Id.
[140] UGI Response to OCA 4-4, Attachment. Attached hereto at Appendix B.
[141] UGI Response to OCA 4-4(c), Attachment. Attached hereto at Appendix B.
[142] 2,817 of these customers are concentrated in Zip Codes 19601, 19602, 19604 (Central Reading, Southeast Reading, Northeast Reading).
[143] 1,580 of these customers are concentrated in 18102 Zip Code (Central Allentown).
[144] Notably, UGI also has an additional 758 Non-CAP CLI customers in the neighboring communities of Steelton (17113) and Colonial Park/Progress (17109)
[145] See UGI Response to OCA 4-16 (b), Attachment. Attached hereto at Appendix B.

I understand that UGI has already agreed to hold multiple outreach events in Lancaster, Wilkes Barre, and Williamsport.[146] I recommend that UGI prioritize scheduling additional future events, at a similar scale and frequency, in the other areas identified in Table 13.

Q: Are there other areas that UGI should target for outreach?

A: Yes, while the highest volume of terminations is in the urban centers listed above, the most aggressive growth in low income terminations is occurring in rural and smaller market areas. Several rural and mid-sized community ZIP codes have seen their confirmed low income terminations nearly double in the last two years. These areas represent a growing high risk tier outside of the major cities:

- Lebanon (17042, 17046): This area has seen the largest rural increase, with terminations jumping from 102 to 206 (+102%).
- Berwick (18603): Terminations rose from 60 to 113 (+88%).
- Pittston/West Pittston (18640): Significant growth from 68 to 114 terminations (+67%).
- Sunbury (17801): Terminations increased from 69 to 108 (+56%).[147]

These areas are reaching termination levels previously only seen in much larger urban centers. I also recommend that UGI target these areas for Universal Service Outreach.

[146] UGI Statement No.12 at 12.
[147] UGI Response to OCA 4-16(b), Attachment. Attached hereto at Appendix B.

B. Hardship Fund

Q: Please briefly describe UGI's Hardship Fund, Operation Share.

A: Operation Share is administered by UGI's universal service program staff.[148] It provides eligible customers with grants up to $600.[149] To qualify for an Operation Share grant, residential customers must:

- Have household income at or below 250% FPL and meet the following requirements:
  - Not have received an Operation Share grant in the last 12 months;
  - Have an outstanding balance on their utility bill;
  - Provide adequate information to demonstrate inability to pay energy bills; and,
  - Have contacted UGI's credit department to discuss their options.[150]

Q: Has UGI made proposals in this proceeding regarding its Operation Share program?

A: While UGI has not proposed changes to the program structure as part of this case, UGI is committing to contribute $1,000,000 annually each year for fiscal years 2027 to 2029 to its Operation Share program.[151]

Q: Does UGI's commitment constitute an overall increase to the Operation Share contribution?

A: No. While I strongly support UGI's proposal to contribute $1,000,000 annually to the Operation Share program, the Operation Share contribution will nonetheless be a reduction for years 2027 to 2029 compared to the 2026 budget. As part of the UGI Gas 2025 Settlement, Paragraph 62(a), the Company increased its Operation Share

[148] 2020-2025 USECP at 13.
[149] Id. at 14.
[150] Id.
[151] UGI Statement No.1 at 10; UGI Statement No.12 at 2.

commitment by $500,000 from $584,500 to $1,084,500 total.[152] In addition, in November 2025, UGI donated an additional $500,000, bringing the total donated to Operation Share to more than $1.5 million for fiscal year 2026.[153] The Settlement provision required that UGI maintain this donation level "until the effective date of rates established in the next base rate case."[154] Thus, the increased contribution will expire upon the effective date of rates in this proceeding and UGI's overall contribution will reduce by $584,500 per year.

While I strongly support UGI's proposed commitment to its Operation Share Program, I recommend that UGI, **at a minimum**, continue its $1,584,500 total contributions to prevent a reduction in available funding for this vital program. However, if any rate increase is approved in this proceeding, I believe it would be appropriate for UGI to contribute additional funds over and above this $1.5 million to account for the additional hardships caused by the impact of such an increase.

VII. Universal Service Cost Recovery

Q: What issues will you discuss in this section of your testimony?

A: I will address UGI's proposal to assign, on a voluntary and negotiated basis, Universal Service and Energy Conservation program costs to Rate XD customers. I propose a broad reallocation of these costs to all customers classes to mitigate the cost impact to residential customers and broaden the reach of these critical affordability programs.

[152] UGI Statement No.12 at 8; UGI.
[153] UGI Statement No.12 at 9
[154] UGI 2025 Rate Case Settlement at ¶ 62(a)

Q: Please explain the current cost recovery mechanism for UGI's Universal Service and Energy Conservation costs.

A: As noted previously in my testimony, UGI's Universal Service and Energy Conservation programs refer to a suite of assistance programs that help low income households remain connected to service. These programs are required by state law to be offered and effectively implemented by UGI and are overseen by the Commission. The foundation of this requirement is in the Natural Gas Choice and Competition Act codified in Chapter 22 in Title 66. There, the General Assembly made several declarations of state policy regarding continued access to natural gas service. It stated:

> (6) After notice and hearings, the commission shall establish for each natural gas distribution company an appropriate nonbypassable, competitively neutral cost-recovery mechanism which is designed to recover fully the natural gas distribution company's universal service and energy conservation costs over the life of these programs. Except as provided in paragraph (10), policies, activities and services under this paragraph shall be funded and spent in each natural gas distribution company's service territory. Nothing in this chapter shall be construed to prohibit public funding or voluntary funding by third parties of a natural gas distribution company's universal service and energy conservation programs.
>
> (7) The commission shall, at a minimum, continue the level and nature of the consumers protections, policies and services within its jurisdiction that are in existence as of the effective date of this chapter to assist low-income retail gas customers to afford natural gas services.
>
> (8) The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each natural gas distribution service territory. The commission shall encourage the use of community-based organizations that have the necessary technical and administrative experience to be the direct providers of services or programs which reduce energy consumption or otherwise assist low-income retail gas customers to afford natural gas service. Programs under this paragraph shall be subject to the administrative oversight of the commission, which shall ensure that the programs are operated in a cost-effective manner.[155]

[155] 66 Pa. C.S. § 2203(6)-(8).

The term "universal service and energy conservation" as used in Chapter 22, was defined by the General Assembly as:

> **"Universal service and energy conservation**." Policies, practices and services that help residential low-income retail gas customers and other residential retail gas customers experiencing temporary emergencies, as defined by the commission, to maintain natural gas supply and distribution services. The term includes retail gas customer assistance programs, termination of service protections and consumer protection policies and services that help residential low-income customers and other residential customers experiencing temporary emergencies to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs and consumer education**.**[156]

For purposes of this case, all the programs collected through UGI's existing and proposed Universal Service Rider meet the definition of the public purpose costs that the General Assembly has required UGI to develop, offer and implement.

Under its current Universal Service Rider, UGI assigns the costs of these programs only to residential customers.[157] In its proposed tariff, UGI continues only assign these costs to residential customers, but also proposes to add that the "rider may also apply to customers receiving service under Rate XD on a negotiated basis,"[158] and that :[t]he USP rate for customers receiving service under Rate XD, if applicable, may differ from the USP rate stated below and may be applied on a volumetric, fixed, charge, percentage or other basis."[159] UGI witness Epler states that the reason for this change is to allow the assignment to Rate XD and "otherwise lower USP costs borne by the Company's residential customers."[160]

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[156] 66 Pa C.S. § 2202 (definitions) ("Universal service and energy conservation") (emphasis in original).
[157] Book X, UGI Exhibit F - UGI Utilities, Inc. – Gas Division., Supplement No. 62 to UGI Gas – PA.P.U.C. No. 7, Seventeenth Revised page No. 58. ("USP Rider (Current")).
[158] Book XI, UGI Exhibit F – UGI Utilities, Inc. – Gas Division, Supplement 63 to UGI Gas – PA P.U.C. No. 7, Eighth Revised Page No. 59.
[159] Id.
[160] UGI Statement No.10 at 22:13-14.

In the Fully Projected Future Test Year, UGI projects these costs to be approximately $30.5 million annually.[161] This amount is simply a projection, and UGI flows the actual costs of the programs, plus reconciliation for under or over collection. It resets its rate quarterly at the same time as it makes a change in its purchased gas costs. Currently, the cost per Mcf imposed for residential customers is $0.06363/Mcf[162].

Q: Historically, these costs have only been recovered from residential customers, why should UGI be required to recover these costs more broadly?

A: There is no rational basis for residential customers to solely bear the burden of these costs. The General Assembly has clearly recognized these costs are public purpose costs because they assist poor Pennsylvania families to be able to maintain access to essential natural gas service. The "cause" of the need for this program is poverty – a societal problem. Residential customers do not cause poverty. This fact was recognized by the Commission in its Final CAP Policy Statement and Order, where the Commission addressed the recovery of universal service program costs. While the Commission did not require jurisdictional utilities to propose specific allocations, the Commission indicated that it is appropriate to consider recovery of the costs of customer assistance programs from all ratepayer classes because "poverty, poor housing stock, and other factors that contribute to households struggling to afford utility service are not just 'residential class' problems."[163] The Commission explained that the provision of universal services to help low income families maintain service to their homes is "a benefit to the economic climate

[161] Book V, UGI Gas Exhibit E – Proof of Revenue, Page 2 of 7.
[162] USP Rider (Current).
[163] Final CAP Policy Statement and Order, Docket No. M-2019-3012599, at 97 (Order entered Nov. 5, 2019); see also 52 Pa. Code §§ 69.265(1), 69.266(b).

of a community."[164] The Commission directed utilities and stakeholders to address CAP cost recovery in utility-specific rate proceedings, indicating that "*the Commission will no longer routinely exempt non-residential classes from universal service obligations*."[165]

Even looking at a model where the "beneficiary pays" causes the conclusion that while the most obvious benefits of universal service programs are apparent to the residential rate class, this is too narrow of a view as there are a multitude of societal benefits which inure to non-residential ratepayers that cannot be ignored. These programs are meant to remediate the impacts of poverty and utility insecurity with long-term and far-ranging impacts for low income households, as well as the surrounding communities in which they live and work.[166] Households who cannot afford utility services are more prone to a host of adverse consequences, including increased rates of health complications and hospitalization, eviction, and food insecurity.[167] For children in low income households, utility insecurity has been linked to adverse impacts on long-term health and developmental delays.[168] Communities of color also continue to experience

[164] Final CAP Policy Statement and Order at 7, 94-96, 107.
[165] Id. at 97 (emphasis added); see also 66 Pa. C.S. § 69.266(b).
[166] See Diana Hernández, Energy Insecurity And Health: America's Hidden Hardship, Health Affairs, available at: https://www.healthaffairs.org/do/10.1377/hpb20230518.472953/ (Last visited April 10, 2026). (as a parallel to energy affordability, discussing the links between energy insecurity and adverse outcomes in health, food insecurity, and access to stable and affordable housing)
[167] Id.; Diana Hernandez, editorial, Energy Insecurity: A Framework for Understanding Energy, the Built Environment, and Health Among Vulnerable Populations in the Context of Climate Change, American Journal of Public Health, Vol.103, No 4 (April 2013), available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC3673265/pdf/AJPH.2012.301179.pdf (last visited April 10, 2026); Diana Hernández, Yumiko Aratani, and Yang Jiang, Energy Insecurity Among Families with Children (January 2014), available at http://www.nccp.org/publications/pdf/text_1086.pdf. (Last visited Apr. 10, 2026).
[168] See Diana Hernández, Yumiko Aratani, and Yang Jiang, Energy Insecurity Among Families with Children (January 2014), available at http://www.nccp.org/publications/pdf/text_1086.pdf (Last visited April 10, 2026). (while the author discusses energy insecurity, parallels exist related to utility insecurity as a whole)

utility insecurity at disproportionate and high levels.[169] Similarly, since low income customers who do not participate in these programs often have significant arrearages,[170] these costs cannot be avoided in rates. They will either be paid as a part of foregone revenue upfront through assistance programs or collected through uncollectible expenses.

Furthermore, many low income assistance program participants are employed, but do not receive a wage that is adequate to afford basic household needs. This is evident from the self-sufficiency data that I discuss earlier in my testimony and from the fact that 30% of CAP customers, 31.7% of LIURP recipients, and 47% of customers who received a hardship fund were employed.[171] The next largest group of low income assistance program participants are retired seniors or individuals on disability who do not receive sufficient social security, disability, or retirement benefits to afford basic life necessities, including energy services.[172]

In addition to the adverse physical health impacts which result from lack of utility services, low income customers who face utility insecurity often struggle with heightened levels of stress, anxiety and depression – and must take time away from work to arrange payments, locate or apply for assistance programs, and arrange for reconnections.[173]

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[169] Environmental and Climate Justice Program, NAACP, Lights Out In The Cold: Reforming Utility Shut-Off Policies as If Human Rights Matter at ix (March 2017), available at https://naacp.org/resources/lights-out-cold (Last visited Apr. 10, 2026) (while the author primarily discusses energy insecurity, parallels exist to utility insecurity as a whole, and its disproportionate impact on communities of color).
[170] See Table 10, supra.
[171] PUC 2024 Universal Service Programs Collections Performance at 50, available at: https://www.puc.pa.gov/media/3771/2024-universal-service-report-final.pdf. (Last visited March 31, 2026).
[172] Id.
[173] Diana Hernandez, Understanding 'energy insecurity' and why it matters to health, Social Science & Medicine, Volume 167, October 2016, available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5114037/ (similar utility insecurity stress with energy). (Last visited Apr. 10, 2026)

These consequences of utility insecurity significantly undermine worker productivity, which – in turn – impacts businesses, nonprofits, governmental entities, schools, and other non-residential customer groups. In addition, low income assistance programs help utility companies to control uncollectible expenses which ultimately impact all ratepayers.

In sum, all customer classes (including industry, business, commerce, educational institutions, hospitals, local and state governments, and other residential customers) benefit from the availability and existence of universal service programs and assistance. It is a sound policy decision for all customers to share the costs of providing these programs to UGI's most vulnerable customers.

Q: If the Commission agrees to assign the costs of the universal service programs to all customers, how do you recommend that they do so?

A: I support a broad allocation of costs to all rate classes. Ultimately, these costs should be assigned to all rate classes based on their respective distribution revenue requirements per the Company's cost of service study (COSS) filed in the current case.[174]

Q: If the Commission rejects broad allocation of universal service costs, do you have an alternative recommendation for allocation?

A: Yes, although I support broad allocation of costs because of the public purpose nature of these programs, the Commission's policy statement, and because all utility ratepayers benefit from the existence of these programs, if the Commission rejects this proposal then, at the very least, these costs should be assessed consistent with UGI's proposal to assign them to Rate class XD, but with the modification that such assignment should be required rather than permissive.

[174] See UGI Utilities, Inc. – Gas Division, Gas Class Cost of Service Study, Schedule 6 – Internal Allocation Factors, Line 44.

VIII. Security Deposits

Q: What are UGI's policy regarding the collection and return of security deposits relative to its low income customers and applicants?

A: UGI's tariff acknowledges that the Company may not require a cash deposit from an applicant who is, based upon household income, confirmed to be eligible for a customer assistance program.[175] UGI's policy states that an applicant is "confirmed to be eligible for a customer assistance program" if the applicant "provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the Company's customer assistance programs."[176] For existing customers that already have monies paid against a security deposit, UGI will only return their deposit if they "become enrolled in the Company's customer assistance programs."[177]

Q: Do you have concerns about this policy?

A: Yes. Section 56.32(e) of the Commission's regulations prohibits utilities from collecting security deposits from customers who are confirmed to be income eligible for its customer assistance programs.

The Commission has issued explicit guidance on this issue and was clear that a low income household does not need to enroll in CAP or another universal service program for the prohibition on security deposits to apply.[178] In its Attachment A to its Ch. 56 Rulemaking Order, the Commission clarified that the prohibition on collecting security

[175] UGI Gas Exhibit F, Current Tariff, Supplement 59 to UGI Gas-PA. PUC No. 7 First Revised Page No. 30.
[176] Id.
[177] Id.
[178] 52 Pa. Code § 56.32(e).

deposits from low income customers is "referring to eligibility based upon the customer's household income – *not on other miscellaneous eligibility criteria that can vary by utility*."[179] The Commission also stated:

> Regarding the concerns expressed about this same section by LICRG that it is eligibility and not actual enrollment into CAP that determines the customer's exemption from deposit requirements, we agree and point out that ***this section specifies "eligible," not "enrolled" or "participating."*** We think this language is sufficient direction that the customer only has to be "eligible" and not actually enrolled in CAP to be exempt from a deposit request.[180]

The Commission also requires both verbal notice of the exemption to be provided to applicants and customers *at the time the security deposit is assessed*, as well as instructions for how the applicant or customer can verify income.[181]

The imposition of a security deposit can pose a significant barrier to low income customers who are already struggling to connect to and maintain service. UGI's security deposit collection policies that are reflected in its current tariff are overly restrictive and do not comport with the Commission's guidance.

Q: Does UGI's policy in its tariff conflict with information provided in discovery?

A: Yes. In response to discovery, UGI indicated that it "releases security deposits on accounts automatically through the Company's customer information and billing systems once they are identified as income verified"[182] In response to confidential discovery, UGI

[179] Rulemaking to Amend the Provisions of 52 Pa. Code, Chapter 56 to Comply with the Amended Provisions of 66 Pa. C.S. Ch. 14, L-2015-2508421, Final Rulemaking Order, Attach. One at 48 (Feb. 28, 2019).
[180] Id. (emphasis added).
[181] Id.; see also 52 Pa. Code §§ 56.36, 56.286.
[182] UGI Response to CAUSE-PA 6-5 and 6-3. Attached hereto at Appendix B.

indicates that it releases the deposit and sends it directly to the customer.[183] However, based on my review of all of the responses and UGI's tariff it is not clear what UGI's actual practices are concerning refunds for existing customers who have paid a deposit and UGI later verifies that the customer is low income. Specifically, it is not clear whether UGI requires the customer to actually enroll in CAP before returning the security deposit and it is unclear applies returned deposits to the customer's account or allows the customer to determine whether the customer wants the security deposit refunded to them directly or whether they want it applied to their account.[184]

Q: How do you recommend UGI reform its security deposit policies?

A: I recommend that UGI amend its tariff and all its internal processes so that customers who have been confirmed to be income eligible for CAP have their security deposit refunded to them regardless of whether they enroll in CAP or not. CAP enrollment is not required and the decision whether the refund is sent directly to customer or applied to the customer's bill should belong to the customer. Both recommendations are consistent with Commission policy. This change should be made immediately and UGI should be required to make all such refunds within 90 days of the effective date of rates.

IX. Purchase of Receivables

Q: What will you be discussing in this portion of your testimony?

A: I will be discussing recommended changes to UGI's Purchase of Receivables (POR) program considering the significant and adverse cost impacts for residential and

[183] UGI Response to CAUSE-PA 6-10 (CONFIDENTIAL). This response is not attached and nothing in the text of my testimony quotes directly from the document.
[184] UGI Response to CAUSE-PA 6-1. Attached hereto at Appendix B.

confirmed low income customers not enrolled in CAP who have chosen to shop with a competitive electric supplier. Specifically, I recommend that UGI provide notice to suppliers that effective January 1, 2027, it will no longer be purchasing the receivables from participating suppliers, unless the supplier provides natural gas service at a price that is at or below UGI's default service price.

Q: Please explain the existing POR program.

A: Because non-CAP residential customers can choose to be served by a retail natural gas supplier, UGI has developed a POR program whereby it agrees to purchase the uncollected receivables the result from a contract between a Natural Gas Supplier (NGS) and its customer. Under UGI's current tariff, Participating NGSs are paid 97.30% of the face value of the residential amounts billed, with this 2.70% discount representing the overall uncollectible rate.[185] The discount is updated whenever UGI updates its uncollectible expense in rate cases through its merchant function charge. In this proceeding, UGI seeks to increase the payment to suppliers to 97.49%.[186] In order to agree to have UGI purchase receivables, NGSs have to agree to abide by the Rules and Regulations in the Choice Supplier Tariff and sign a POR Agreement and Affidavit.[187] Suppliers may only be paid through the POR for "basic natural gas supply services" and not other goods, services or other products.[188] If a supplier participates in POR, then the

[185] Book X, UGI Exhibit F - UGI Utilities, Inc. – Gas Division., Supplement No. 59 to UGI Gas – PA.P.U.C. No. 7S, Sixth Revised Page No. 115.
[186] Book XI, UGI Exhibit F - UGI Utilities, Inc. – Gas Division., Supplement No. 63 to UGI Gas – PA.P.U.C. No. 7S, Seventh Revised Page No. 115.
[187] Copies of the POR Agreement and Affidavit are available for download on UGI's Energy Management Website. See https://ugi.outsystemsenterprise.com/UGIProcedures_FO/Procedures?Division=Gas&SubMenu=Choice. Then click on "Choice Suppler Registration Information" to download copies. (Last visited March 31, 2026).
[188] Book X, UGI Exhibit F - UGI Utilities, Inc. – Gas Division., Supplement No. 59 to UGI Gas – PA.P.U.C. No. 7S, Sixth Revised Page No. 115.

uncollected account balance is owned by UGI and UGI proceeds to bill and collect those charges like it would for all charges that it bills and collects for default service customers. This includes, but is not limited to, taking steps to terminate service for non-payment.

Q: What is your concern with the POR program as it is currently structured?

A: Because suppliers are paid upfront with a discount that only reflects the overall uncollectible rate, they have very little incentive to moderate the prices that they charge customers and have no incentive to be concerned if they are charging customers prices that are significantly more than what UGI would charge customers. From the supplier's perspective it does not matter what they charge because UGI will buy the receivables and must manage the collection process. This is problematic because overall customers served by NGSs pay significantly more than they otherwise would pay had they remained on default service.

Q: Please explain how much more residential shopping customers have paid compared to default service customers?

A: In response to discovery, UGI provided the following data points for the period from January 2023 through February 2026 for residential shopping and default service customers and for the period from January 2023 through January 2026 for Confirmed Low Income Customers (non-CAP):[189]

- Total number of shopping customers
- Total billed usage of shopping customers
- Total billed commodity supply charges
- Total number of default service customers
- Total billed usage of default service customers

[189] UGI Response to CAUSE-PA 5-1, Attachment and CAUSE-PA 5-2, Attachment. Attached hereto at Appendix B.

- Total billed commodity charges for default service customers.

Based on this information, I was able to arrive at the average cost per Mcf per customer by month for both shopping and default service customers, the dollar amount difference in the average cost per customer by month for shopping versus default service customers, the percentage difference in the average cost per customer for shopping versus default service customers, and the aggregate difference in cost per customer for shopping versus default service customers. This information is presented in Appendix C, Cicero Exhibits C-5 and C-6 that is attached to my testimony. In summary, over the period from January 2023 through February 2026, residential customers who were served by a retail NGS paid in aggregate **$57.9 million more** than they would have otherwise paid had they all been on default service during that same period. Of that amount, confirmed low income customers who were served by an NGS paid in aggregate **$5 million** more than if they had all been on default service during that same period. Furthermore, confirmed low income shopping customers paid on average higher prices than residential shopping customers as a whole for a comparable period.

Table 14: Average NGS Price v. Price to Compare[190]

Customer Type	Average Cost per Mcf Paid by Shopping Customers	Average PTC per Mcf	Difference per Mcf	Difference Shopping % higher than PTC
Residential Customers January 2023-February 2026	**$9.35**	**$6.37**	**$2.98**	**46.8%**
Confirmed Low Income (Non-CAP) January 2023 - January 2026	**$9.45**	**$6.35**	**$3.10**	**48.8%**

[190] See Appendix C, Exhibit Cicero C-3 through C-5.

Q: What is your concern?

A: My concern is that low income customers already face high energy burdens at exiting rates charged by UGI. NGS rates that are almost 50% higher than UGI's applicable rate for commodity costs exacerbate these households' inability to afford service. Furthermore, I am concerned that these higher costs flow through to the uncollectible expenses paid for by all ratepayers and lead to increased debt, arrearages, and terminations for residential customers above that which would have occurred had all customers paid prices that were no higher than UGI's default service price.

Q: What is your recommendation?

A: My recommendation is that UGI revise its POR program to require that to participate in POR and have UGI buy its receivables an NGS would have to certify that its rates are at or below the applicable default service price. If a supplier wants to take advantage of UGI's POR program, it should not be permitted to charge rates that are in excess of what UGI charges. Under my proposal, NGSs would still be able to offer contracts to customers at any rate they wish, but if those rates are higher than the default service price, they would not be able to participate in POR.

Q: Would this change mean that customers would have to receive a dual bill from UGI and the NGS?

A: No. The supplier could still participate in UGI's consolidated billing program but would not be paid for its supply charges until or unless UGI was paid by the customers. Furthermore, under UGI's supplier tariff, suppliers who elect not to participate in POR

because they wish to charge more than UGI's charges would be responsible for their own collections if their charges go unpaid.[191]

Q: When should this change go into effect?

A: I am proposing that UGI issue a notice to all suppliers indicating that effective January 1, 2027 and forward all suppliers who wish to remain in the POR program will need to complete an updated POR Agreement and Affidavit that would require all charges for contracts or renewals of contracts entered after that period be at or below the default service price to compare in order to have any charges after that date be included in the POR program. If a supplier elects to participate, they will remain in POR, if a supplier elects to charge rates higher than UGI's charges, they could elect to remain in UGI's consolidated billing program, but their charges would be non-POR eligible. This change would be made on a forward going basis and would provide all suppliers with notice of the change before it goes into effect.

X. Termination Notices and Other Tariff Cleanup

Q: What will you address in this section of your testimony?

A: I will address minor changes that I believe need to be made to clean up UGI's current tariff. First, UGI should amend Rule 9 involving termination and discontinuance of service. As written, UGI's current tariff reads:

> 9.1 (a) Termination of Service. The Company may terminate service on reasonable notice and remove its equipment in case of Customer's (i) nonpayment of an undisputed delinquent account, (ii) failure to complete payment of a deposit, provide a guarantee of payment or establish credit,

[191] See Book X, UGI Exhibit F - UGI Utilities, Inc. – Gas Division., Supplement No. 59 to UGI Gas – PA.P.U.C. No. 7S, Sixth Revised Page No. 115 ("The termination and reconnection provisions of Chapter 14 and Chapter 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing.")

> (iii) failure to permit access to meters, service connections or other property for the purpose of replacement, maintenance, repair or meter reading, (iv) failure to comply with the material terms of a payment arrangement, or (v) violation of tariff Rules and Regulations. The Company may terminate service promptly and without notice for Customer's (i) Unauthorized Use of Service delivered on or about the affected dwelling or premises, (ii) fraud or material misrepresentation of the Customer's identify for the purpose of obtaining service, (iii) abuse of or tampering with the meters, connections or other equipment of the Company, (iv) violating tariff Rules and Regulations which endanger the safety of a person or the integrity of the Company's distribution system, (v) tendering payment for reconnection of service that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice, or (vi) after receiving termination notice from the Company, tendering payment which is subsequently dishonored under 13 Pa. C.S. § 3502, or, in the case of an electronic payment, that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice. Prior to restoration of service terminated for any of the foregoing reasons, the Company may require a payment in advance of all arrearages, applicable deposit, and a reconnect charge of seventy-three dollars ($73). Effective November 1, 2025, confirmed low income residential customers who provide verification of household income will not be assessed reconnection fees.

These provisions are a mix of grounds for involuntary termination of service, some of which require notice and some of which can be performed without notice. Having them all lumped together with a catchall of "reasonable notice" does not adequately inform customers of their rights. Furthermore, UGI should eliminate its tariff provision that allows it to generally terminate service for "violation of tariff Rules and Regulations." This provision is overly broad and is not authorized by existing PUC regulations of the Public Utility Code. Thus, I recommend that UGI amend its tariff to read as follows (with changes in red and underlined):

> 9.1 (a) Termination of Service. **Termination with Notice.** The Company may terminate service on at least ten (10) days written ~~reasonable~~ notice and remove its equipment in case of Customer's (i) nonpayment of an undisputed delinquent account, (ii) failure to complete payment of a deposit, provide a guarantee of payment or establish credit, (iii) failure to permit

access to meters, service connections or other property for the purpose of replacement, maintenance, repair or meter reading, or (iv) failure to comply with the material terms of a payment arrangement. ~~or (v) violation of tariff Rules and Regulations.~~

Termination without Notice. The Company may terminate service promptly and without notice for Customer's (i) Unauthorized Use of Service delivered on or about the affected dwelling or premises, (ii) fraud or material misrepresentation of the Customer's identify for the purpose of obtaining service, (iii) abuse of or tampering with the meters, connections or other equipment of the Company, (iv) violating tariff Rules and Regulations which endanger the safety of a person or the integrity of the Company's distribution system, (v) tendering payment for reconnection of service that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice, or (vi) after receiving termination notice from the Company, tendering payment which is subsequently dishonored under 13 Pa. C.S. § 3502, or, in the case of an electronic payment, that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice.

Restoration of Service. Prior to restoration of service terminated for any of the foregoing reasons, the Company may require a payment in advance of all arrearages, applicable deposit, and a reconnect charge of seventy-three dollars ($73). Effective November 1, 2025, confirmed low income residential customers who provide verification of household income will not be assessed reconnection fees.

In addition, there are several places within UGI's tariff where it mentions state agencies with their old names – such as the Department of Public Welfare as opposed to the Department of Human Services – and references statutory provisions that have expired – such as Chapter 14 of the Public Utility Code. When it files its compliance tariff in this case, UGI should eliminate all references to expired sections of the Public Utility Code and should correct all outdated references to state agency names.

XI. Conclusion

Q: Does this conclude your direct testimony?

A: Yes.

CAUSE-PA Statement 1, Cicero

Appendix A

Resume of Patrick Cicero

Patrick M. Cicero, Esq.

pcicero@pautilitylawproject.org | 717-576-2588 (mobile)

PROFESSIONAL EXPERIENCE

PENNSYLVANIA UTILITY LAW PROJECT HARRISBURG, PENNSYLVANIA
Of Counsel, February 2025 - Present
Executive Director, July 2015 - January 2020
Co-Director, January 2013 - June 2015
Staff Attorney, January 2011 - December 2012

The Pennsylvania Utility Law Project (PULP) is a specialized legal aid office and member of the Pennsylvania Legal Aid Network. PULP's mission is to promote policies that enable consumers with low and moderate income to receive and maintain affordable utility and energy services and to live in energy-efficient homes.

As Of Counsel, in cases where I am not serving as an attorney, I provide analysis and testimony for PULP's clients in administrative proceedings before relevant state and federal agencies.

When I am not serving as a policy or technical expert, I lead the legal and policy work of the office and provide high-level legal expertise and strategic guidance to the organization. I seek to ensure that PULP's legal and policy advocacy and strategies are designed to effectively and zealously represent the interests of PULP's clients before administrative, judicial, and legislative bodies.

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE HARRISBURG, PENNSYLVANIA
Consumer Advocate, December 2021 – January 2025
(*Confirmed by the Pennsylvania Senate June 7, 2022*)

The Office of Consumer Advocate (OCA) is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission (PUC), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General. As Consumer Advocate, I served as the head of the office and directed all policy and legal advocacy.

PENNSYLVANIA LEGAL AID NETWORK, INC. HARRISBURG, PENNSYLVANIA
Executive Director, January 2020 – December 2021

The Pennsylvania Legal Aid Network, Inc. (PLAN, Inc.) is a client-centered organization that provides leadership, funding, training, and support to a coordinated network of independent legal aid organizations that deliver civil legal aid to low-income Pennsylvanians and victims of domestic violence. As Executive Director, I provided strategic leadership and direction to PLAN Inc.'s activities and oversaw its advocacy, fundraising, and management.

PROFESSIONAL EXPERIENCE – CONT.

HONORABLE SYLVIA H. RAMBO, DISTRICT JUDGE HARRISBURG, PENNSYLVANIA
THE UNITED STATES DISTRICT COURT FOR THE MIDDLE DISTRICT OF PENNSYLVANIA
Senior Judicial Law Clerk, May 2009 - December 2010
Judicial Law Clerk, August 2002 - August 2004

Analyzed federal and state law on civil and criminal motions in all phases of litigation. Drafted judicial opinions in response to civil and criminal motions, including motions to suppress, motions to dismiss, summary judgment, post-trial motions, and habeas corpus petitions. Drafted comments that were given by Judge Rambo at public speaking events and supervised her law clerks and judicial interns.

MIDPENN LEGAL SERVICES HARRISBURG, PENNSYLVANIA
Managing Attorney, January 2009 - April 2009
Staff Attorney, September 2004 - December 2008

MidPenn Legal Services (MidPenn) is a non-profit organization providing legal services to low-income individuals and families, the disabled, the elderly, children, and survivors of domestic violence. I led MidPenn's Consumer Unit where I focused on litigating consumer and housing cases related to anti-predatory mortgage lending and consumer bankruptcy and defended clients against unscrupulous debt collection practices.

TEACHING EXPERIENCE

MESSIAH UNIVERSITY MECHANICSBURG, PENNSYLVANIA

Adjunct Professor of Sociology and Criminal Justice (Periodic since 2015)

Courses Taught:
Social Inequality
Criminal Law and Criminal Procedure
Ethics in the Criminal Justice System

Visiting Lecturer of Sociology and Criminal Justice, August 2014 - May 2015

Courses Taught:
Introduction to Sociology
Sociocultural Theory
Social Inequality
Social Conflict, Justice and Peacemaking
Religion and Society
Evidence, Search and Seizure

Adjunct Instructor in General Education

Courses Taught: Law and Social Issues

EDUCATION

TEMPLE UNIVERSITY, BEASLEY SCHOOL OF LAW PHILADELPHIA, PENNSYLVANIA
Juris Doctor, magna cum laude, 2002

MESSIAH COLLEGE (NOW MESSIAH UNIVERSITY) MECHANICSBURG, PENNSYLVANIA
Bachelor of Arts in Sociology, magna cum laude, 1999

PUBLICATIONS

Pennsylvania Consumer Law by Carolyn Carter, Bisel Publishing Co., 2003, Supp. 2010-2012, Contributing Author.

MEMBERSHIPS, AFFILIATIONS, COMMITTEES

Pennsylvania State Bar (admitted 2002)
Middle District of Pennsylvania Bar (admitted 2004)
Pennsylvania Bar Association, House of Delegates, Zone 3, (2021-2024)
Pennsylvania Department of Human Services
- LIHEAP Advisory Committee (2015-2020 and 2021-2025)
Pennsylvania Department of Environmental Protection,
- Pennsylvania Energy Development Authority, *ex officio* (2021-2025)
Pennsylvania Public Utility Commission
- Consumer Advisory Council (2015-2020, 2025-Present)
- Pennsylvania Sustainable Energy Board, *ex officio* (2021-2025)
Pennsylvania Department of Community and Economic Development
- Weatherization Assistance Program, Policy Advisory Council (2015-2020)
National Association of State Utility Consumer Advocates (NASUCA), Executive Committee (2023-2025)
Upper Allen Township, Sewer Advisory Board (by appointment),
- Term: September 2025-December 2029.

LIST OF PROCEEDINGS

Below is a list of proceedings in which I have provided expert testimony. Links to my testimony are provided for all complete cases. Cases listed as ongoing cases are at various stages of litigation and will be updated as completed.

COMPLETED CASES
Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716. • Natural gas distribution base rate proceeding. • Direct and Surrebuttal testimony regarding rate design, customer service, and low income customer affordability.
Pennsylvania Public Utility Commission v. Philadelphia Gas Works, Docket No. R-2025-3053112. • Natural gas distribution base rate proceeding. • Direct, Rebuttal, and Surrebuttal testimony regarding rate design, customer service, and low income customer affordability.
Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Docket No. R-2025-3053499. • Natural gas distribution base rate proceeding. • Direct and Surrebuttal testimony regarding rate design, customer service, and low income customer affordability.
Pennsylvania Public Utility Commission v. Pittsburgh Water Sewer Authority, Docket Nos. R-2025-3055010, 3055011, and 3055012 • Water/wastewater/stormwater distribution base rate proceeding. • Direct, Rebuttal, and Surrebuttal testimony regarding rate design, customer service, low income program design, and low income customer affordability.
Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation, Docket No. R-2025-3057164. • Electric distribution base rate proceeding. • Direct and Surrebuttal testimony regarding rate design, customer service, low income program design, energy efficiency, net metering, and low income affordability.

ONGOING CASES
Joint Application of American Water Works Company, Inc., Essential Utilities, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC and Peoples Gas Company LLC and Alpha Merger Sub, Inc. for a Certificate of Public Convenience under Sections 1102(a)(3) and 2210(c) of the Public Utility Code and All Other Necessary Approvals to Effect a Change of Control of Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., and Peoples Natural Gas Company LLC Docket Nos. A-2025-3058927; A-2025-3058928; A-2025-3058929 • Merger Application of two of the largest water and wastewater utilities in the country. • Testimony regarding whether the merger results in an affirmative public benefit and protections needed to ensure low income customers receive benefit.
Pennsylvania Public Utility Commission v. UGI Utilities, Inc. Gas Division, Docket No. R-2025-3059523. • Natural gas distribution base rate proceeding. • Testimony regarding rate design, customer service, low income program design, and low income customer affordability.
Petition of FirstEnergy Pennsylvania Electric Company for Approval of Its Default Service Program for the Period June 1, 2027 to May 31, 2031, Docket No. P-2026-3060298. • Electric distribution company default service procurement plan. • Testimony regarding default service procurement and retail electric market protections for low income households.

CAUSE-PA Statement 1, Cicero
Appendix B

Interrogatories of CAUSE-PA to UGI

UGI Response to CAUSE-PA 1-3
UGI Response to CAUSE-PA 1-4
UGI Response to CAUSE-PA 1-5, Attachment
UGI Response to CAUSE-PA 1-6, Attachment
UGI Response to CAUSE-PA 1-7, Attachment
UGI Response to CAUSE-PA 1-9 (a), Attachment
UGI Response to CAUSE-PA 1-9 (b), Attachment
UGI Response to CAUSE-PA 1-14, Attachment
UGI Response to CAUSE-PA 1-17
UGI Response to CAUSE-PA 1-18
UGI Response to CAUSE-PA 1-22, Attachment
UGI Response to CAUSE-PA 3-1(a), Attachment
UGI Response to CAUSE-PA 3-1(b)
UGI Response to CAUSE-PA 3-1(d)
UGI Response to CAUSE-PA 3-1(h)
UGI Response to CAUSE-PA 3-4
UGI Response to CAUSE-PA 3-5
UGI Response to CAUSE-PA 4-7
UGI Response to CAUSE-PA 5-1, Attachment
UGI Response to CAUSE-PA 5-2, Attachment
UGI Response to CAUSE-PA 6-1
UGI Response to CAUSE-PA 6-3
UGI Response to CAUSE-PA 6-5
UGI Response to CAUSE-PA 6-11
UGI Response to CAUSE-PA 6-17

Interrogatories of OCA to UGI

UGI Response to OCA 2-18(B), Attachment
UGI Response to OCA 4-4, Attachment
UGI Response to OCA 4-6, Attachment
UGI Response to OCA 4-16 (b), Attachment
UGI Response to OCA 7-2, Attachment
UGI Response to OCA 8-50, Attachment

Interrogatories of I&E to UGI

UGI Response to I&E RR-6-D, Attachment

CAUSE-PA-1-3

Request:

As of the most recent date available, please identify the number of UGI Gas CAP customers whose bills were calculated based on:

A. Average monthly bill;
B. Percentage of income (disaggregated by income tier);
C. Minimum bill; or
D. Other (please specify).

Please provide this data in a live excel spreadsheet.

Response:

Data is provided as of March 1, 2026:

A. 7,291
B. 14,305
C. 5,045
D. Not Applicable

Prepared by or under the supervision of: Brian J. Meilinger

CAUSE-PA-1-4

Request:

Refer to the Joint Petition for Approval of Settlement of All Issues in UGI Utilities, Inc. – Gas Division rate case at Docket No. R-2024-3052716, paragraph 67 (a). Please identify all categories or identifiers that UGI Gas includes when calculating its "confirmed low income customer" count for the purposes of reporting pursuant to 52 Pa. Code § 62.5. If UGI Gas uses a different definition or categorization criteria for "confirmed low income customer" for any purpose, please identify the alternative definition and/or criteria and explain why a different definition is used.

Response:

Upon receipt of the Joint Petition for Approval of Settlement of All Issues in UGI Utilities, Inc. – Gas Division rate case at Docket No. R-2024-3052716, the Company adopted the definition of "confirmed low income" consistent with 52 Pa. Code § 62.2, which includes both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines. This includes adjusting the internal reports used to tabulate data for reporting under 52 Pa. Code § 62.5.

Prepared by or under the supervision of: Brian J. Meilinger

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 1 (1-25)
Delivered on March 19, 2026

CAUSE-PA-1-5

Request:

From January 2023 to date, disaggregated by month and year, as of the last day of the month/year, how many of UGI Gas's customers were/are categorized as confirmed low income? If UGI Gas uses multiple definitions of the term "confirmed low income", as identified in CAUSE-PA to UGI 1-4, please separately provide the data requested for each definition.

Please provide this data in a live excel spreadsheet.

Response:

Please see Attachment CAUSE-PA-1-5.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided in the response includes both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, figures prior to that date may include customers whose low income status was not yet on record with the Company.

Prepared by or under the supervision of: Brian J. Meilinger

UGI UTILITIES, INC. - GAS DIVISION
COUNT OF CONFIRMED LOW INCOME CUSTOMERS BY MONTH
JANUARY 2023 - JANUARY 2026

Month	2023	2024	2025	2026
January	48,161	54,894	62,605	68,289
February	48,695	55,513	63,327	
March	49,303	56,144	64,091	
April	50,336	57,202	65,441	
May	50,482	57,492	65,462	
June	50,695	57,547	65,726	
July	50,819	58,135	65,963	
August	51,376	58,093	65,467	
September	51,456	58,476	66,093	
October	52,306	59,317	66,465	
November	53,404	60,720	68,020	
December	54,155	61,754	68,975	

CAUSE-PA-1-6

Request:

From January 2023 to date, disaggregated by month and year, as of the last day of the month/year, how many of UGI Gas's customers were/are enrolled in UGI's CAP?

Please provide this data in a live excel spreadsheet.

Response:

Please see Attachment CAUSE-PA-1-6.

Prepared by or under the supervision of: Brian J. Meilinger

UGI UTILITIES, INC. - GAS DIVISION
COUNT OF CAP CUSTOMERS BY MONTH*
JANUARY 2023 - JANUARY 2026

Month	2023	2024	2025	2026
January	20226	24274	24007	26250
February	19227	23011	22436	
March	21383	23521	24649	
April	20713	24625	25127	
May	22144	24664	25064	
June	22047	23761	24907	
July	21859	24876	25271	
August	23334	24409	24769	
September	22364	23350	24796	
October	23655	23820	25366	
November	23714	22686	25702	
December	23219	23666	26192	

*Based upon customer being billed under the CAP program during the month

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CAUSE-PA-1-7

Request:

From January 2023 to date, disaggregated by month and year, as of the last day of the month/year, how many residential customers does/did UGI Gas serve? Please explain how UGI arrived at this figure and include citations and/or copies of any and all workpapers used to perform the calculation.

Please provide this data in a live excel spreadsheet.

Response:

Please see Attachment CAUSE-PA-1-7 in both electronic Excel format and PDF.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc.- Gas Division
Total Residential Customers 1/
January 2023-Present

January 2023	February 2023	March 2023	April 2023	May 2023	June 2023	July 2023	August 2023	September 2023	October 2023	November 2023	December 2023
618,859	619,491	619,942	616,822	615,196	613,550	612,164	610,923	612,331	616,057	620,736	623,436

January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024
625,126	625,883	626,041	623,689	620,922	619,077	616,795	616,170	617,178	621,632	625,733	629,337

January 2025	February 2025	March 2025	April 2025	May 2025	June 2025	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025
630,927	631,381	631,429	629,132	626,717	624,824	622,490	621,606	622,113	626,987	631,514	634,702

January 2026	February 2026
635,818	636,412

1/ Residential Monthly Customer Counts tie to month end close counts reported by Revenue Accounting, data is not specifically reported on a "snapshot" last day of month basis.

CAUSE-PA-1-9

Request:

From January 2023 to date, disaggregated by month and year (as of the last day of the month/year), please provide for UGI Gas customers:

A. Residential UGI Gas customers, excluding confirmed low income customers and CAP customers;

B. Confirmed low income UGI Gas customers, excluding CAP customers;

Please provide this data in a live excel spreadsheet.

Response:

A. Please see Attachment CAUSE-PA-1-9(a).

B. Please see Attachment CAUSE-PA-1-9(b).

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, figures prior to that date may include customers whose low income status was not yet on record with the Company.

Prepared by or under the supervision of: Brian J. Meilinger

UGI UTILITIES, INC. - GAS DIVISION

COUNT OF RESIDENTIAL CUSTOMERS, EXCLUDING CONFIRMED LOW INCOME AND CAP, BY MONTH

JANUARY 2023 - JANUARY 2026

Month	2023	2024	2025	2026
January	567750	568045	570116	571366
February	568277	569080	570208	
March	568787	569239	570857	
April	569201	570264	571166	
May	567495	568665	569177	
June	565824	566240	568097	
July	563755	565670	566599	
August	562731	563510	564320	
September	560464	562465	564108	
October	562282	563714	564497	
November	564418	565146	566417	
December	566126	568319	569693	

UGI UTILITIES, INC. - GAS DIVISION

COUNT OF CONFIRMED LOW INCOME CUSTOMERS, EXCLUDING CAP, BY MONTH

JANUARY 2023 - JANUARY 2026

Month	2023	2024	2025	2026
January	35614	37218	41424	42561
February	36640	38457	43371	
March	35767	38447	41956	
April	37115	38434	42602	
May	36148	38386	42444	
June	36182	38844	42556	
July	36128	38290	42165	
August	35528	38204	41827	
September	35966	38988	42103	
October	35680	39121	41606	
November	36533	41163	42501	
December	37440	41108	42897	

CAUSE-PA-1-14

Request:

From January 2023 to date, disaggregated by month and year (as of the last day of the month/year), how many UGI Gas customers were terminated for nonpayment each month, disaggregated by the following customer segments:

A. All residential UGI Gas customers;
B. Residential UGI Gas customers, excluding confirmed low income customers and CAP customers;
C. Confirmed low income UGI Gas customers;
D. Confirmed low income UGI Gas customers, excluding CAP customers;
E. UGI Gas CAP customers.

Please provide this data in a live excel spreadsheet.

Response:

A-E. Please see Attachment CAUSE-PA-1-14.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, disconnections prior to that date may include customers whose low income status was not yet on record with the Company at the time of disconnection.

Prepared by or under the supervision of: Daniel V. Adamo

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR RESIDENTIAL CUSTOMERS
FOR CALENDAR YEAR 2025

	A. All Residential	B. Residential without CLI and CAP	C. All CLI	D. CLI without CAP	E. CAP
January	32	32	-	-	-
February	110	110	-	-	-
March	158	158	-	-	-
April	3,995	2,606	1,389	1,138	251
May	3,346	2,155	1,191	1,110	81
June	4,069	2,476	1,593	1,427	166
July	4,779	2,759	2,020	1,794	226
August	4,111	2,242	1,869	1,498	371
September	4,406	2,277	2,129	1,772	357
October	2,875	1,409	1,466	1,249	217
November	1,834	996	838	837	1
December	-	-	-	-	-
Total	29,715	17,220	12,495	10,825	1,670

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR RESIDENTIAL CUSTOMERS
FOR CALENDAR YEAR 2024

	A. All Residential	B. Residential without CLI and CAP	C. All CLI	D. CLI without CAP	E. CAP
January	86	86	-	-	-
February	164	164	-	-	-
March	216	216	-	-	-
April	4544	3176	1368	1018	350
May	3847	2688	1159	1037	122
June	3543	2431	1112	943	169
July	5356	3412	1944	1507	437
August	4515	2836	1679	1320	359
September	3675	2201	1474	1085	389
October	2571	1513	1058	778	280
November	1912	1115	797	609	188
December	-	-	-	-	-
Total	30,429	19,838	10,591	8,297	2,294

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR RESIDENTIAL CUSTOMERS
FOR CALENDAR YEAR 2023

	A. All Residential	B. Residential without CLI and CAP	C. All CLI	D. CLI without CAP	E. CAP
January	5	5	-	-	-
February	285	285	-	-	-
March	315	315	-	-	-
April	5,129	3,832	1297	1131	166
May	4,367	3,344	1023	827	196
June	4,026	2,895	1131	936	195
July	3,755	2,653	1102	863	239
August	4,893	3,305	1588	1236	352
September	3,270	2,145	1125	874	251
October	2,615	1,721	894	680	214
November	2,409	1,487	922	669	253
December	-	-	-	-	-
Total	31,069	21,987	9,082	7,216	1,866

CAUSE-PA-1-17

Request:

What is the average annual income of UGI Gas's currently identified confirmed low income customers?

Response:

The average annual income of confirmed low income customers is $20,146.32, which has been annualized, since the Company collects income per month.

Prepared by or under the supervision of: Brian J. Meilinger

CAUSE-PA-1-18

Request:

What is the average annual income of UGI Gas's currently enrolled CAP customers?

Response:

The average annual income of CAP customers is $17,208, which has been annualized, since the Company collects income per month.

Prepared by or under the supervision of: Brian J. Meilinger

CAUSE-PA-1-22

Request:

From January 2023 to date, disaggregated by month and year, as of the last day of the month/year, please provide the total dollars in debt and the average arrearage level for each of the following UGI Gas customer segments:

A. All residential UGI Gas customers;
B. Residential UGI Gas customers, excluding confirmed low income customers and CAP customers;
C. Confirmed low income UGI Gas customers;
D. Confirmed low income UGI Gas customers, excluding CAP customers;
E. UGI Gas CAP customers.

Please provide this data in a live excel spreadsheet.

Response:

A-E. Please see Attachment CAUSE-PA-1-22.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, average and totals prior to that date may include customers whose low income status was not yet on record with the Company at the time of the reported arrearage.

Please note that tracking for the debt and arrearage level disaggregated by month and year for the subsets listed above commenced in October 2023. Consequently, data prior to this date is not available.

Prepared by or under the supervision of: Daniel V. Adamo

UGI UTILITIES, INC. – GAS DIVISION
AVERAGE AND TOTAL ARREARS FOR RESIDENTAL CUSTOMERS
FOR CALENDAR MONTHS IN 2023-2026

	2023		2024		2025		2026	
	Average	Total	Average	Total	Average	Total	Average	Total
January			$ 501.65	$ 64,400,693.69	$ 438.44	$ 58,611,987.81	$ 472.11	$ 67,371,785.16
February			$ 515.35	$ 71,324,142.18	$ 481.22	$ 67,818,016.73		
March			$ 534.13	$ 73,635,705.63	$ 522.17	$ 74,563,725.74		
April			$ 507.66	$ 69,369,133.47	$ 505.03	$ 77,493,713.87		
May			$ 457.08	$ 65,380,743.12	$ 481.11	$ 72,464,553.97		
June			$ 427.24	$ 58,837,282.94	$ 423.87	$ 65,172,321.17		
July			$ 408.59	$ 51,118,936.86	$ 420.98	$ 45,113,965.33		
August			$ 437.35	$ 46,069,836.21	$ 385.74	$ 49,298,571.10		
September			$ 365.05	$ 43,710,948.93	$ 306.61	$ 44,722,402.41		
October	$ 420.03	$ 50,618,313.70	$ 364.74	$ 42,439,162.54	$ 360.65	$ 44,311,694.58		
November	$ 424.91	$ 53,417,360.67	$ 406.52	$ 43,090,408.63	$ 375.28	$ 44,815,838.07		
December	$ 456.64	$ 59,641,481.63	$ 394.47	$ 48,878,186.54	$ 451.12	$ 60,028,798.03		

UGI UTILITIES, INC. – GAS DIVISION
AVERAGE AND TOTAL ARREARS FOR RESIDENTAL CUSTOMERS EXCLUDING CLI AND CAP
FOR CALENDAR MONTHS IN 2023-2026

	2023		2024		2025		2026	
	Average	Total	Average	Total	Average	Total	Average	Total
January			$ 409.58	$ 36,723,278.65	$ 332.13	$ 30,102,603.68	$ 318.59	$ 30,560,446.85
February			$ 422.57	$ 41,744,035.75	$ 375.69	$ 36,400,483.56		
March			$ 440.28	$ 43,051,926.96	$ 416.66	$ 40,835,185.32		
April			$ 409.94	$ 39,521,024.81	$ 396.17	$ 42,589,562.77		
May			$ 355.77	$ 36,401,405.75	$ 365.34	$ 38,244,034.50		
June			$ 322.41	$ 31,343,055.00	$ 307.72	$ 33,714,869.54		
July			$ 299.03	$ 25,764,203.51	$ 284.51	$ 25,228,831.90		
August			$ 319.53	$ 21,908,813.52	$ 241.60	$ 20,575,773.71		
September			$ 253.24	$ 20,514,356.67	$ 215.38	$ 16,998,838.28		
October	$ 326.74	$ 27,697,189.06	$ 251.90	$ 19,521,185.74	$ 196.58	$ 15,508,987.87		
November	$ 333.70	$ 29,580,486.11	$ 260.86	$ 19,893,286.49	$ 201.17	$ 15,034,271.07		
December	$ 366.68	$ 33,877,528.59	$ 286.22	$ 23,657,602.56	$ 283.11	$ 27,171,552.02		

UGI UTILITIES, INC. – GAS DIVISION
AVERAGE AND TOTAL ARREARS FOR RESIDENTAL CLI CUSTOMERS
FOR CALENDAR MONTHS IN 2023-2026

	2023		2024		2025		2026	
	Average	Total	Average	Total	Average	Total	Average	Total
January			$ 699.99	$ 23,983,807.89	$ 653.12	$ 26,751,742.44	$ 787.03	$ 36,270,874.22
February			$ 730.67	$ 25,838,016.79	$ 703.97	$ 29,619,654.75		
March			$ 744.96	$ 26,743,918.07	$ 742.89	$ 31,904,199.55		
April			$ 724.85	$ 26,265,780.56	$ 750.48	$ 33,214,166.74		
May			$ 692.59	$ 25,453,497.09	$ 734.98	$ 32,644,097.04		
June			$ 662.28	$ 24,326,741.36	$ 711.85	$ 31,457,451.63		
July			$ 636.77	$ 22,632,827.88	$ 691.40	$ 29,588,318.83		
August			$ 645.07	$ 21,821,584.41	$ 670.57	$ 28,088,160.10		
September			$ 588.52	$ 21,166,540.95	$ 656.25	$ 27,390,545.31		
October	$ 630.08	$ 19,505,425.44	$ 580.23	$ 21,083,848.70	$ 655.59	$ 28,659,933.12		
November	$ 632.64	$ 20,424,028.31	$ 581.55	$ 21,503,332.43	$ 667.12	$ 29,748,353.98		
December	$ 662.07	$ 22,166,830.44	$ 602.80	$ 23,537,624.40	$ 708.58	$ 32,594,801.69		

*The arrears for CAP participants used to calculate this dataset is comprised of the total account arrears as opposed to solely the CAP balances.

UGI UTILITIES, INC. – GAS DIVISION
AVERAGE AND TOTAL ARREARS FOR RESIDENTAL CLI CUSTOMERS WITHOUT CAP
FOR CALENDAR MONTHS IN 2023-2026

	2023		2024		2025		2026	
	Average	Total	Average	Total	Average	Total	Average	Total
January			$ 694.90	$ 16,915,162.68	$ 638.65	$ 18,244,286.65	$ 796.86	$ 24,559,146.59
February			$ 726.26	$ 18,430,308.69	$ 690.75	$ 20,406,680.17		
March			$ 742.07	$ 18,876,087.43	$ 736.51	$ 22,069,570.31		
April			$ 719.43	$ 18,245,526.51	$ 749.80	$ 22,913,005.37		
May			$ 680.56	$ 17,207,162.94	$ 736.47	$ 22,321,805.52		
June			$ 652.35	$ 16,293,180.84	$ 720.30	$ 21,380,719.55		
July			$ 628.20	$ 15,005,078.46	$ 700.65	$ 19,885,133.43		
August			$ 637.91	$ 14,417,411.91	$ 682.71	$ 18,935,744.50		
September			$ 576.76	$ 13,888,409.00	$ 674.55	$ 18,394,980.41		
October	$ 630.28	$ 13,492,414.27	$ 570.80	$ 13,932,705.15	$ 680.90	$ 19,243,548.50		
November	$ 631.20	$ 14,107,409.51	$ 571.26	$ 14,225,970.02	$ 693.46	$ 19,967,346.24		
December	$ 658.21	$ 15,362,058.54	$ 591.78	$ 15,792,218.98	$ 727.03	$ 21,799,362.78		

UGI UTILITIES, INC. – GAS DIVISION
AVERAGE AND TOTAL ARREARS FOR RESIDENTAL CAP CUSTOMERS
FOR CALENDAR MONTHS IN 2023-2026

	2023		2024		2025		2026	
	Average	Total	Average	Total	Average	Total	Average	Total
January			$ 748.63	$ 10,762,252.36	$ 708.96	$ 10,265,097.48	$ 767.68	$ 12,252,191.72
February			$ 783.21	$ 11,149,797.74	$ 759.53	$ 11,010,853.00		
March			$ 799.71	$ 11,707,691.24	$ 786.44	$ 11,658,970.11		
April			$ 779.85	$ 11,602,582.15	$ 779.66	$ 11,991,145.73		
May			$ 762.45	$ 11,772,174.43	$ 761.37	$ 11,898,713.95		
June			$ 721.58	$ 11,201,047.10	$ 717.68	$ 11,347,272.84		
July			$ 686.91	$ 10,349,654.89	$ 690.35	$ 10,672,113.74		
August			$ 687.57	$ 9,743,610.78	$ 656.81	$ 9,787,052.89		
September			$ 635.24	$ 9,308,183.26	$ 624.57	$ 9,328,583.72		
October	$ 657.69	$ 9,428,710.37	$ 621.73	$ 8,985,271.65	$ 608.51	$ 9,559,158.21		
November	$ 660.92	$ 9,729,465.05	$ 703.85	$ 8,971,152.12	$ 617.52	$ 9,814,220.76		
December	$ 699.01	$ 10,401,894.50	$ 647.33	$ 9,428,365.00	$ 697.65	$ 11,057,883.23		

*The arrears for CAP participants used to calculate this dataset is comprised of the total account arrears as opposed to solely the CAP balances.

CAUSE-PA-3-1(a)

Request:

See UGI St. No 1. at 6:23-7:3.

a. Please provide UGI's actual calculated return on common equity (ROE) for the end each calendar quarter for the period from January 1, 2023 through December 31, 2025.

Response:

Please see Attachment CAUSE-PA-3-1(a).

ROEs provided for the twelve months ended 3/31/2023 through 9/30/2024 are those submitted to the Commission for use in the Report on the Quarterly Earnings of Jurisdictional Utilities. For subsequent periods, the ROEs were not submitted to the Commission as the Company was involved in a rate filing. ROEs for the twelve months ended 12/31/2024 through 12/31/2025 were calculated in a manner consistent with those submitted to the Commission.

Prepared by or under the supervision of: Hans G. Bell

UGI Utilities, Inc. - Gas Division
Calculated Return on Equity

Twelve Months Ended	Calculated ROE
12/31/2025	10.43%
9/30/2025	10.43%
6/30/2025	10.85%
3/31/2025	11.32%
12/31/2024	11.12%
9/30/2024	11.17%
6/30/2024	12.11%
3/31/2024	12.39%
12/31/2023	12.19%
9/30/2023	11.43%
6/30/2023	12.94%
3/31/2023	13.45%

CAUSE-PA-3-1(b)

Request:

See UGI St. No 1. at 6:23-7:3.

b. For each quarter for the same period as set forth in part a, please indicate whether UGI's "ability to attract capital needed to make investments that support operating a safe and reliable distribution system" was jeopardized by that actual return on common equity.

Response:

UGI's ability to attract capital needed to make investments that support operating a safe and reliable distribution system was not jeopardized during any quarter in the period from January 1, 2023 through December 31, 2025. However, the Company's claim is based on the forward-looking test period (for the year ended September 30, 2027), not a backward-looking period. Please see UGI Gas Statement No. 1, pages 6 and 7.

Prepared by or under the supervision of: Hans G. Bell

CAUSE-PA-3-1(d)

Request:

See UGI St. No 1. at 6:23-7:3.

d. In his statement, Mr. Bell asserts that an ROE of 7.7% "could potentially jeopardize UGI's ability to attract capital needed to make investments that support operating a safe and reliable distribution system." Other than the testimony submitted in this case by Mr. D'Ascendis regarding UGI's requested ROE, please provide all internal analysis that Mr. Bell or anyone at UGI undertook that supports this statement.

Response:

As more fully described in UGI Gas Statement No. 1, the Direct Testimony of Hans G. Bell, page 6, lines 21 – 23, Mr. Bell did not undertake any additional analysis and relied on the analysis provided by Mr. D'Ascendis in his testimony and UGI Gas Exhibit B.

Prepared by or under the supervision of: Hans G. Bell

CAUSE-PA-3-1(h)

Request:

See UGI St. No 1. at 6:23-7:3.

h. Has UGI or its parent company been unable to attract capital from the capital markets at UGI's current ROE? If yes, please explain all steps the UGI has taken to seek capital contributions within the last 12 months.

Response:

UGI Corp (ultimate parent of UGI Utilities, Inc. - Gas Division) has not issued equity since the finalization of the last UGI Gas rate case.

Prepared by or under the supervision of: Hans G. Bell

CAUSE-PA-3-4

Request:

See UGI St. 8 at 5:13:21. Mr. D'Ascendis asserts the following: "Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk." Please answer the following questions about this statement:

a. Is it Mr. D'Ascendis's contention that 10.75% return on equity is the lowest return on equity that the Public Utility Commission could authorize to allow UGI to have "sufficient earnings"? If yes, please explain why an ROE that is lower than this would not allow UGI to have sufficient earnings.

b. If the Public Utility Commission were to authorize a return on equity that was 9.75% is it Mr. D'Ascendis's position that UGI would not be able to raise capital in the capital markets at this level? If yes, please explain the basis for this conclusion.

c. If the Public Utilities Commission were to authorize a return on equity of 8.75% s it Mr. D'Ascendis's position that UGI would not be able to raise capital in the capital markets at this level? If yes, please explain the basis for this conclusion.

Response:

a. It is Mr. D'Ascendis' opinion that the range of ROEs between 10.34% and 11.52% is applicable to UGI Gas, and his specific point estimate of 10.75% represents Mr. D'Ascendis' evaluation of the Company's risk within that reasonable range. Consistent with the Hope and Bluefield comparable risk standards, a 10.75% return on equity will ensure that the Company has a level of earnings commensurate with other enterprises corresponding risks, sufficient to maintain the integrity of presently invested capital, and permit the attraction of needed new capital at a reasonable costs and terms.

CAUSE-PA's definition of "sufficient earnings" is unclear. As such, Mr. D'Ascendis is unable to answer the request.

CAUSE-PA-3-4 (Continued)

b. The appropriate ROE is needed to attract new capital at reasonable costs and terms, not simply to access the capital markets. Since the hypothetical ROE referenced above is not in Mr. D'Ascendis' reasonable range of ROEs, it is his opinion that while the Company may be able to raise capital at that level of ROE, it may not be able to do so under reasonable costs and terms.

c. Please refer to the response in part b. above.

Prepared by or under the supervision of: Dylan W. D'Ascendis

CAUSE-PA-3-5

Request:

See UGI St. 8 at 5:18. How does Mr. D'Ascendis define the term "reasonable cost" as used in this line of his testimony?

Response:

A "reasonable cost" is a return to investors that is sufficient to maintain the integrity of presently invested capital and permits the attraction of needed new capital at a cost that is competitive with other firms of comparable risk.

Prepared by or under the supervision of: Dylan W. D'Ascendis

CAUSE-PA-4-7

Request:

If the Commission were to deny UGI's request to continue its WNA, please explain whether, in Mr. Taylor's opinion, the Company would be unable to provide safe and reliable service to its customers. If the answer to this question is yes, please explain in detail the basis for this response.

Response:

The question is based on the premise that the WNA is connected to the Company's ability to provide safe and reliable service. That premise is incorrect. The WNA is a rate design mechanism intended to address weather-related volatility in customer bills and distribution revenue recovery; it does not determine whether the Company can safely and reliably operate its system. The WNA provides the Company a reasonable opportunity to recover its allowed cost of service.

Prepared by or under the supervision of: John D. Taylor

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 5 (1-15)
Delivered on March 23, 2026

CAUSE-PA-5-1

Request:

Please provide the following for January 2023 to date, disaggregated by month and by year, as of the last day of the month/year, for UGI Gas:

A. The total usage of residential customers;
B. The total dollar amount billed for generation supply charges for residential customers inclusive of both default service customers and residential shopping customers;
C. The total number of residential shopping customers;
D. The total usage of residential shopping customers;
E. The total amount billed for generation supply charges for residential shopping customers;
F. The total number of residential default service customers;
G. The total usage of residential default service customers;
H. The total amount billed for generation supply charges for residential default service customers.

Please provide this data in a live Excel spreadsheet.

Response:

Please see Attachment CAUSE-PA-5-1 provided in Excel.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential Customers, Sales, and Commodity Supply Charges-Shopping and Default Service
January 2023 - February 2026

Month	*A. Total billed usage of Residential Customers-Mcf's	B. Total billed commodity supply charges for Residential customers - $	*C. Total Residential shopping customers	*D. Total billed usage of Residential shopping customers-Mcf's	E. Total billed commodity supply charges for Residential shopping customers - $	F. Total Residential default service customers	G. Total billed usage of Residential default service customers- Mcf's	H. Total billed commodity supply charges for Residential default service customers - $
Jan-23	8,662,027	$80,151,868	74,585	1,017,672	$10,480,307	544,274	7,644,355	$69,671,561
Feb-23	7,217,304	$66,830,469	74,687	833,004	$8,635,401	544,804	6,384,300	$58,195,067
Mar-23	7,540,443	$65,244,176	77,047	886,344	$9,111,030	542,895	6,654,099	$56,133,147
Apr-23	4,243,642	$33,769,693	78,325	502,367	$4,729,543	538,497	3,741,275	$29,040,150
May-23	2,511,214	$19,970,779	79,716	307,801	$2,871,165	535,480	2,203,414	$17,099,614
Jun-23	1,247,705	$9,965,427	80,740	159,532	$1,522,435	532,810	1,088,173	$8,442,991
Jul-23	811,306	$6,522,045	81,435	109,634	$1,077,666	530,729	701,672	$5,444,379
Aug-23	809,207	$6,520,922	81,829	111,387	$1,106,370	529,094	697,820	$5,414,553
Sep-23	775,564	$6,225,871	82,458	106,708	$1,035,909	529,873	668,856	$5,189,962
Oct-23	1,350,818	$10,750,761	83,449	181,871	$1,681,117	532,608	1,168,947	$9,069,644
Nov-23	3,202,030	$25,271,745	84,510	417,484	$3,662,748	536,226	2,784,546	$21,608,997
Dec-23	6,437,514	$43,443,425	85,446	871,019	$7,425,619	537,990	5,566,495	$36,017,806
Jan-24	8,456,366	$42,575,819	84,331	1,140,550	$9,881,161	540,795	7,315,816	$32,694,659
Feb-24	7,966,798	$40,436,479	83,221	1,053,060	$9,092,383	542,662	6,913,738	$31,344,096
Mar-24	6,384,275	$31,345,097	82,229	833,397	$7,118,399	543,812	5,550,878	$24,226,697
Apr-24	5,178,669	$24,279,418	81,425	651,798	$5,546,275	542,264	4,526,871	$18,733,143
May-24	2,215,951	$10,462,509	80,635	280,242	$2,453,487	540,287	1,935,709	$8,009,022
Jun-24	1,068,099	$5,345,804	80,196	139,162	$1,280,614	538,881	928,937	$4,065,190
Jul-24	813,315	$4,359,164	79,974	107,623	$1,036,612	536,821	705,693	$3,322,552
Aug-24	760,622	$4,071,295	79,590	100,299	$971,809	536,580	660,323	$3,099,486
Sep-24	805,881	$4,290,891	79,579	103,835	$996,481	537,599	702,046	$3,294,410
Oct-24	1,294,803	$6,840,842	79,720	168,042	$1,551,287	541,912	1,126,761	$5,289,555
Nov-24	2,486,491	$12,917,844	79,894	302,128	$2,662,949	545,839	2,184,364	$10,254,895
Dec-24	6,804,969	$38,252,487	80,188	838,283	$7,182,269	549,149	5,966,686	$31,070,218
Jan-25	10,551,661	$65,176,714	81,335	1,338,645	$11,610,440	549,592	9,213,016	$53,566,274
Feb-25	9,769,417	$60,272,905	81,605	1,228,950	$10,553,534	549,776	8,540,468	$49,719,371
Mar-25	8,009,125	$52,465,346	81,867	1,017,392	$8,735,493	549,562	6,991,733	$43,729,853
Apr-25	4,521,499	$31,932,550	81,742	566,396	$4,961,448	547,390	3,955,103	$26,971,102
May-25	2,199,142	$15,633,753	81,485	280,666	$2,544,775	545,232	1,918,476	$13,088,977
Jun-25	1,417,514	$10,144,318	81,623	179,000	$1,695,838	543,201	1,238,514	$8,448,480
Jul-25	827,816	$6,027,211	81,671	112,591	$1,148,554	540,819	715,225	$4,878,657
Aug-25	734,988	$5,379,637	82,037	98,058	$1,035,535	539,569	636,930	$4,344,102
Sep-25	831,471	$6,068,047	82,349	111,009	$1,153,684	539,764	720,462	$4,914,363
Oct-25	1,258,244	$9,110,985	83,154	167,145	$1,667,426	543,833	1,091,100	$7,443,559
Nov-25	3,237,853	$23,162,844	83,995	407,192	$3,819,383	547,519	2,830,662	$19,343,461
Dec-25	8,027,783	$58,041,554	84,776	1,053,994	$9,866,875	549,926	6,973,789	$48,174,678
Jan-26	10,133,810	$74,041,355	85,178	1,337,047	$12,580,960	550,640	8,796,764	$61,460,395
Feb-26	11,342,352	$83,216,286	84,934	1,498,503	$14,434,369	551,478	9,843,849	$68,781,918

*Includes dual billed residential customers

CAUSE-PA-5-2

Request:

Please provide the following for January 2023 to date, disaggregated by month and by year, as of the last day of the month/year, for UGI Gas:

A. The total usage of confirmed low income customers;
B. The total dollar amount billed for generation supply charges for all confirmed low income customers inclusive of both default service customers and residential shopping customers;
C. If different than what was provided in Part a, the total usage of all non-CAP (Customer Assistance Program) confirmed low income customers;
D. If different than what was provided in Part a, the total amount billed for generation supply charges for all non-CAP confirmed low income customers;
E. The total amount billed for generation supply charges for non-CAP confirmed low income shopping customers;
F. The total amount billed for generation supply charges for non-CAP default service confirmed low income customers.

Please provide this data in a live Excel spreadsheet.

Response:

Please see Attachment CAUSE-PA-5-2.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided includes both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines. Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, figures prior to that date may include customers whose low income status was not yet on record with the Company.

Additionally, the figures provided represent bills issued for service attributed to the requested months and years, since bills are not all generated on the last day of each month.

Prepared by or under the supervision of: Brian J. Meilinger

UGI UTILITIES, INC. - GAS DIVISION
USAGE AND GENERATION SUPPLY CHARGES FOR CONFIRMED LOW INCOME CUSTOMERS BY MONTH
JANUARY 2023 TO JANUARY 2026

	A. Total Usage CLI Customers (MCF)	B. Total amount billed for generation supply charges for all CLI Customers	C. Total usage of all non-CAP CLI customers (MCF)	D. Total amount billed for generation supply charges non-CAP CLI customers	E. Total amount billed for generation supply charges for non-CAP CLI shopping customers	F. Total amount billed for generation supply charges for non-CAP default service
Jan-23	7872	$7,288,548	5585	$5,203,412	$755,056	$4,448,356
Feb-23	7394	$6,842,442	5341	$4,972,117	$703,417	$4,268,699
Mar-23	6643	$5,682,167	4585	$3,960,765	$616,348	$3,344,416
Apr-23	4362	$3,470,663	3017	$2,427,609	$377,350	$2,050,259
May-23	2328	$1,851,529	1539	$1,238,477	$194,138	$1,044,339
Jun-23	1118	$868,596	748	$582,171	$98,129	$484,041
Jul-23	784	$623,469	535	$430,337	$76,293	$354,044
Aug-23	693	$547,536	463	$369,549	$68,383	$301,166
Sep-23	770	$609,305	520	$416,371	$74,935	$341,436
Oct-23	1382	$1,091,688	870	$693,358	$118,316	$575,042
Nov-23	3662	$2,880,469	2327	$1,846,869	$302,394	$1,544,475
Dec-23	7186	$4,622,722	4721	$3,082,594	$601,974	$2,480,620
Jan-24	8693	$4,321,234	5588	$2,912,997	$752,390	$2,160,607
Feb-24	8642	$4,291,782	5694	$2,955,331	$735,383	$2,219,948
Mar-24	6938	$3,302,304	4486	$2,239,874	$573,179	$1,666,695
Apr-24	5420	$2,459,116	3401	$1,627,414	$425,395	$1,202,019
May-24	2290	$1,050,477	1398	$680,761	$182,637	$498,124
Jun-24	1107	$533,798	701	$355,087	$96,670	$258,417
Jul-24	804	$420,873	509	$281,760	$75,908	$205,852
Aug-24	760	$397,345	480	$265,606	$70,741	$194,865
Sep-24	890	$396,965	569	$268,104	$69,390	$198,715
Oct-24	1415	$693,711	866	$447,775	$115,641	$332,134
Nov-24	3335	$1,689,922	2128	$1,122,368	$261,058	$861,310
Dec-24	8535	$4,553,791	5384	$2,974,551	$664,952	$2,309,599
Jan-25	12042	$7,285,556	7605	$4,727,172	$1,005,755	$3,721,417
Feb-25	12711	$7,825,968	8328	$5,267,769	$1,102,347	$4,165,422
Mar-25	9283	$6,405,122	5749	$4,069,186	$837,961	$3,231,224
Apr-25	5607	$4,140,394	3396	$2,570,318	$492,580	$2,077,738
May-25	2616	$2,021,584	1568	$1,245,351	$245,315	$1,000,036
Jun-25	1690	$1,278,973	1001	$785,024	$155,877	$629,147
Jul-25	965	$692,540	594	$440,196	$100,319	$339,876
Aug-25	859	$623,695	529	$399,320	$91,487	$307,833
Sep-25	1011	$734,194	620	$466,122	$107,090	$359,032
Oct-25	1520	$1,030,169	888	$625,074	$139,229	$485,845
Nov-25	4933	$3,494,509	2827	$2,059,702	$434,197	$1,625,504
Dec-25	10695	$7,395,796	6265	$4,442,152	$951,191	$3,490,961
Jan-26	13469	$9,739,367	7945	$5,897,263	$1,278,614	$4,618,650

CAUSE-PA-6-1

Request:

Please specifically describe all instances where UGI informs low income customers about the availability of the exemption from security deposit collection and ability to receive a refund of their security deposit.

Response:

UGI Gas informs low-income customers about the availability of the security deposit exemption and the ability to receive a refund of their security deposit through several touchpoints. When a customer is identified as verified low-income through enrollment in a qualifying program, the customer's account is automatically updated and any held security deposit is released at that time. Customers are notified of this action via their account statement reflecting the deposit return.

Additionally, information regarding security deposit exemptions for low-income customers is made available through UGI Gas's CCRs. For self-reported low income customers, customers are advised that they will be sent a CAP application/waiver letter. Please see CAUSE-PA-6-9.1 (waiver letter) and CAUSE-PA-6-9.2 (email confirmation).

Please reference CONFIDENTIAL Attachment OCA-3-2.4, page 70, for additional procedures related to security deposit exemptions.

Prepared by or under the supervision of: Daniel V. Adamo

CAUSE-PA-6-3

Request:

From January 2023 to date, disaggregated by month and year, as of the last day of the month/ year, please indicate:

A. How many security deposits UGI Gas has collected from confirmed low-income customers;

B. The total number of confirmed low income customers for whom UGI Gas held/ is holding a security deposit;

C. The total dollar value of security deposits held for UGI Gas's confirmed low income customers;

D. How many of these collected security deposits have been returned to confirmed low income customers.

Please provide this data in a live Excel spreadsheet.

Response:

A - D. Please see Attachment CAUSE-PA-6-3.

Please note that data in response A includes all residential applicants that are billed to pay a security deposit. The Company does not track this information by confirmed low-income status.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided in Parts (B), (C) and (D) includes both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines. Confirmed Low Income Status is based on a snapshot of customer data as of November 30, 2025, because timestamped income data is not readily available for historical reporting. Therefore, figures prior to that date may include customers whose low-income status was not yet on record with the Company.

The Company does not require a security deposit from an applicant who is, based upon household income, confirmed to be eligible for a customer assistance program. An applicant is confirmed to be eligible for a customer assistance

CAUSE-PA-6-3 (Continued)

program by the Company if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the Company's customer assistance programs.

A deposit is assessed for a self-certified low-income customer; however, any monies paid against the security deposit will be directly refunded, along with applicable interest, upon income verification as described above.

Prepared by or under the supervision of: Daniel V. Adamo

CAUSE-PA-6-5

Request:

Please describe the steps UGI Gas uses to investigate whether it is holding security deposits of confirmed low income customers, and the procedures related to how the security deposit is returned to a confirmed low income customer. Please also provide a copy of any and all current written policies, procedures, and/ or other documents which describe UGI Gas's existing policies related to collection and return of security deposits from confirmed low income customers.

Response:

UGI Gas releases security deposits on accounts automatically through the Company's customer information and billing system once they are identified as income verified per the process described in CAUSE-PA-6-3.

Prepared by or under the supervision of: Daniel V. Adamo

CAUSE-PA-6-11

Request:

For each calendar year ending December 31, 2023 through December 31, 2025, how much net profit did UGI Gas earn?

Response:

Net income for UGI Gas for its Fiscal Years ended September 30:

Fiscal Year 2023 – $202,282,856
Fiscal Year 2024 – $207,423,537
Fiscal Year 2025 - $203,740,613

Prepared by or under the supervision of: Vivian K. Ressler

CAUSE-PA-6-17

Request:

Reference UGI St. 12 at 16:17-21.

A. Please describe in detail the methodology used by Experian that resulted in an estimated low income count of 98,785.

B. Does UGI have demographic income data for every one of its residential customers?

C. If the answer to subpart b. above is anything other than an unequivocal yes, please describe why UGI believes that the Experian data accurately counts the number of estimated low income customers within its service territory.

Response:

A. Please see HIGHLY CONFIDENTIAL Attachment CAUSE-PA-1-11 for Experian's January 2026 data assessment and methodology which includes estimated low income counts of 96,137. The methodology used to derive this number is consistent with the methodology used to derive the 2023 figure of 98,785 reported in the Direct Testimony of Brian J. Meilinger, UGI Gas Statement No. 12, at 16:17-21.

B. No.

C. Experian accurately counts the number of estimated low-income customers because their process utilizes insights on actual UGI Gas customers. For the January 2026 data assessment, there was a 90% match rate on name and address. This is in comparison to the methodology of calculating estimated low-income customers reported annually to the Bureau of Consumer Services which is derived by using the United States Census Bureau's American Community Survey 5-year poverty level estimates by county, multiplied by the number of UGI Gas customers in that county.

Prepared by or under the supervision of: Brian J. Meilinger

OCA-2-18

Request:

Please provide the monthly (or most frequently available) balance sheet and income statements for the Company for each year from the past five years to the most currently available in live Excel format.

Response:

Please see Attachment OCA-2-18 (A) for quarterly balance sheets and Attachment OCA-2-18 (B) for quarterly income statements for UGI Utilities, Inc.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended March 31, 2021
Revenues	$ 442
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	202
Operating and administrative expenses	62
Operating and administrative expenses — related parties	7
Depreciation	29
	300
Operating income	142
Interest expense	(14)
Income before income taxes	128
Income tax expense	(29)
Net income	$ 99

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended June 30, 2021
Revenues	$ 181
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	67
Operating and administrative expenses	55
Operating and administrative expenses — related parties	5
Depreciation	29
Other operating expense, net	1
	157
Operating income	24
Pension and other postretirement plans non-service income	1
Interest expense	(14)
Income before income taxes	11
Income tax expense	(2)
Net income	$ 9

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30, 2021
Revenues	$ 1,070
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	456
Operating and administrative expenses	232
Operating and administrative expenses — related parties	21
Depreciation	118
Other operating expense, net	1
	828
Operating income	242
Pension and other postretirement plans non-service income	2
Interest expense	(55)
Income before income taxes	189
Income tax expense	(43)
Net income	$ 146

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended December 31, 2021
Revenues	$ 349
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	169
Operating and administrative expenses	56
Operating and administrative expenses — related parties	6
Depreciation	31
Other operating expense, net	1
	263
Operating income	86
Pension and other postretirement plans non-service income	2
Interest expense	(14)
Income before income taxes	74
Income tax expense	(17)
Net income	$ 57

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended March 31, 2022
Revenues	$ 587
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	319
Operating and administrative expenses	66
Operating and administrative expenses — related parties	6
Depreciation	31
	422
Operating income	165
Pension and other postretirement plans non-service income	2
Interest expense	(15)
Income before income taxes	152
Income tax expense	(37)
Net income	$ 115

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended June 30, 2022
Revenues	$ 235
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	107
Operating and administrative expenses	55
Operating and administrative expenses — related parties	5
Depreciation	32
Other operating (income) expense, net	(2)
	197
Operating income	38
Pension and other postretirement plans non-service income	2
Interest expense	(14)
Income before income taxes	26
Income tax expense	(7)
Net income	$ 19

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30, 2022
Revenues	$ 1,364
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	684
Operating and administrative expenses	234
Operating and administrative expenses — related parties	22
Depreciation	126
	1,066
Operating income	298
Pension and other postretirement plans non-service income	7
Interest expense	(58)
Income before income taxes	247
Income tax expense	(52)
Net income	$ 195

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended December 31, 2022
Revenues	$ 499
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	282
Operating and administrative expenses	65
Operating and administrative expenses — related parties	5
Depreciation	32
Other operating expense, net	1
	385
Operating income	114
Pension and other postretirement plans non-service income	1
Interest expense	(19)
Income before income taxes	96
Income tax expense	(23)
Net income	$ 73

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended June 30, 2023
Revenues	$ 226
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	92
Operating and administrative expenses	62
Operating and administrative expenses — related parties	5
Depreciation	33
	192
Operating income	34
Pension and other postretirement plans non-service income	1
Interest expense	(18)
Income before income taxes	17
Income tax expense	(4)
Net income	$ 13

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended March 31, 2023
Revenues	$ 649
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	356
Operating and administrative expenses	71
Operating and administrative expenses — related parties	5
Depreciation	33
Other operating expense, net	1
	466
Operating income	183
Pension and other postretirement plans non-service income	1
Interest expense	(17)
Income before income taxes	167
Income tax expense	(38)
Net income	$ 129

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30, 2023
Revenues	$ 1,547
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	794
Operating and administrative expenses	263
Operating and administrative expenses — related parties	22
Depreciation	133
Other operating expense, net	2
	1,214
Operating income	333
Pension and other postretirement plans non-service income	4
Interest expense	(71)
Income before income taxes	266
Income tax expense	(60)
Net income	$ 206

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended December 31, 2023
Revenues	$ 406
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	176
Operating and administrative expenses	64
Operating and administrative expenses — related parties	5
Depreciation	36
Other operating expense, net	2
	283
Operating income	123
Pension and other postretirement plans non-service income	1
Interest expense	(20)
Income before income taxes	104
Income tax expense	(24)
Net income	$ 80

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended March 31, 2024
Revenues	$ 520
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	213
Operating and administrative expenses	67
Operating and administrative expenses — related parties	7
Depreciation	36
Other operating expense, net	1
	324
Operating income	196
Interest expense	(21)
Income before income taxes	175
Income tax expense	(40)
Net income	$ 135

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended June 30, 2024
Revenues	$ 212
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	70
Operating and administrative expenses	64
Operating and administrative expenses — related parties	5
Depreciation	36
	175
Operating income	37
Pension and other postretirement plans non-service income	1
Interest expense	(19)
Income before income taxes	19
Income tax expense	(5)
Net income	$ 14

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30, 2024
Revenues	$ 1,305
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	513
Operating and administrative expenses	261
Operating and administrative expenses — related parties	23
Depreciation	145
Other operating expense, net	1
	943
Operating income	362
Pension and other postretirement plans non-service income	3
Interest expense	(81)
Income before income taxes	284
Income tax expense	(65)
Net income	$ 219

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended December 31, 2024
Revenues	$ 400
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	170
Operating and administrative expenses	63
Operating and administrative expenses — related parties	7
Depreciation	38
	278
Operating income	122
Pension and other postretirement plans non-service income (costs)	2
Interest expense	(22)
Income before income taxes	102
Income tax benefit (expense)	(23)
Net income	$ 79

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended March 31, 2025
Revenues	$ 647
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	326
Operating and administrative expenses	70
Operating and administrative expenses — related parties	8
Depreciation	39
Other operating expense, net	(1)
	442
Operating income	205
Pension and other postretirement plans non-service income (costs)	1
Interest expense	(23)
Income before income taxes	183
Income tax expense	(41)
Net income	$ 142

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended June 30, 2025
Revenues	$ 240
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	98
Operating and administrative expenses	66
Operating and administrative expenses — related parties	7
Depreciation	39
Other operating expense (income), net	(1)
	209
Operating income	31
Pension and other postretirement plans non-service income	1
Interest expense	(21)
Income before income taxes	11
Income tax expense	(3)
Net income	$ 8

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30, 2025
Revenues	$ 1,468
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	660
Operating and administrative expenses	266
Operating and administrative expenses — related parties	32
Depreciation	155
Other operating expense, net	-
	1,113
Operating income	355
Pension and other postretirement plans non-service income	4
Interest expense	(87)
Income before income taxes	272
Income tax expense	(59)
Net income	$ 213

UGI Utilities, Inc.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Three Months Ended December 31, 2025
Revenues	$ 491
Costs and expenses:	
Cost of sales — gas and purchased power (excluding depreciation shown below)	235
Operating and administrative expenses	70
Operating and administrative expenses — related parties	7
Depreciation	41
	353
Operating income	138
Pension and other postretirement plans non-service income (costs)	1
Interest expense	(25)
Income before income taxes	114
Income tax benefit (expense)	(26)
Net income	$ 88

OCA-4-4

Request:

In Excel format, for each zip code identified in response to Question No. 3, please provide:

a. The number of residential customers;

b. The number of confirmed low-income customers (including CAP);

c. The number of confirmed low-income customers (excluding CAP);

d. The number of CAP participants.

Response:

For subparts a-d, please see Attachment OCA-4-4.

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided in parts (b) and (c) included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income status for the above responses is based on a snapshot of customers as of November 30, 2025.

Prepared by or under the supervision of: Brian J. Meilinger

ZIP	Residential Customers
15437	-
15522	926
15537	-
15825	-
15864	17
16049	71
16054	-
16058	1
16213	73
16214	235
16217	43
16220	45
16225	1
16232	409
16233	428
16235	501
16239	191
16240	3
16254	608
16255	49
16260	141
16301	380
16319	174
16323	-
16326	186
16329	-
16331	27
16332	47
16334	158
16341	-
16344	-
16346	109
16353	797
16361	61
16364	197
16373	127
16374	157
16375	1
16652	1,478
16662	380
16673	318

16720	507
16724	74
16729	5
16730	8
16731	1,166
16733	1
16740	4
16743	1,734
16745	38
16746	568
16748	1,149
16749	647
16750	173
16822	23
16825	-
16830	2,091
16833	450
16843	54
16850	2
16855	45
16863	45
16866	502
16878	133
16881	3
16901	4,007
16910	23
16911	153
16912	729
16914	470
16915	2,138
16917	494
16918	1
16920	817
16921	401
16922	991
16923	455
16925	702
16926	53
16927	184
16928	578
16929	877
16930	240

16932	135
16933	2,126
16935	455
16936	725
16937	46
16939	103
16940	143
16941	19
16942	207
16943	85
16945	12
16946	1,011
16947	1,492
16948	619
16950	1,070
16974	-
17003	2,390
17004	112
17007	672
17009	245
17010	63
17011	10,188
17013	7,986
17015	3,166
17016	26
17018	255
17022	4,844
17025	4,251
17026	180
17028	21
17030	1
17033	2,961
17034	627
17036	4,431
17038	232
17042	9,134
17043	2,286
17044	2,651
17046	5,297
17050	10,733
17051	6
17052	51

17055	8,370
17057	4,536
17060	78
17065	358
17066	267
17067	2,229
17070	3,667
17072	85
17073	586
17078	4,941
17084	101
17087	235
17093	26
17099	143
17101	490
17102	2,884
17103	3,683
17104	5,836
17105	1
17109	5,743
17110	7,005
17111	8,623
17112	7,517
17113	3,509
17120	2
17177	1
17201	117
17202	408
17222	167
17233	23
17250	114
17254	4
17257	3,124
17260	8
17268	2,990
17319	323
17320	7
17325	47
17339	325
17501	6
17504	52
17505	18

17508	1
17512	3,699
17517	1,314
17519	17
17520	1,072
17522	2,100
17536	5
17537	24
17538	995
17540	1,635
17543	8,091
17545	2,483
17547	1,969
17550	494
17551	2,076
17552	4,415
17554	1,602
17557	1,676
17566	82
17567	36
17569	500
17570	29
17572	53
17578	453
17579	118
17584	716
17601	13,914
17602	13,080
17603	17,949
17604	3
17701	12,875
17702	2,520
17721	128
17724	1,326
17726	-
17728	91
17730	95
17735	18
17737	467
17738	-
17740	1,238
17745	1,720

17748	198
17751	182
17752	713
17754	2,368
17756	1,239
17760	101
17762	120
17764	631
17765	63
17772	184
17777	1,402
17779	4
17801	3,605
17810	16
17815	4,566
17821	2,520
17822	1
17824	3
17831	170
17833	56
17834	112
17837	1,625
17842	62
17844	4
17847	2,629
17850	151
17851	1,090
17856	191
17857	1,804
17860	34
17866	679
17868	63
17870	1,778
17872	1,125
17876	456
17886	165
17887	106
17889	76
17901	3,132
17921	278
17922	122
17929	11

17931	78
17936	36
17938	4
17941	1
17951	25
17954	15
17961	3
17965	223
17970	34
17972	249
17974	-
17978	1
18011	497
18013	1,571
18014	832
18015	6,891
18016	2
18017	7,324
18018	9,042
18020	3,499
18030	38
18031	3,372
18032	1,848
18034	1,888
18036	1,415
18037	813
18040	5,251
18042	12,744
18045	8,817
18049	2,891
18051	403
18052	4,085
18055	2,604
18058	7
18062	5,725
18064	3,148
18067	3,163
18068	20
18069	749
18070	22
18071	776
18072	766

18080	439
18083	61
18085	50
18087	189
18088	51
18091	254
18092	53
18101	860
18102	10,390
18103	6,405
18104	8,735
18106	1,174
18109	4,115
18195	5
18201	7,515
18202	2,536
18219	229
18221	14
18222	907
18223	2
18224	215
18225	42
18229	1,164
18235	1,284
18237	58
18239	30
18249	209
18251	3
18301	2,268
18302	3
18321	17
18326	3
18327	100
18336	132
18337	1,256
18343	27
18344	50
18346	10
18347	42
18349	3
18351	5
18355	3

18360	2,377
18366	-
18370	18
18403	2,814
18407	3,713
18410	326
18411	6,059
18414	749
18419	377
18421	575
18428	368
18431	2,321
18433	1,781
18434	1,784
18440	46
18447	3,555
18452	2,030
18466	17
18470	13
18471	429
18472	89
18473	84
18503	380
18504	8,265
18505	7,049
18507	2,071
18508	3,894
18509	4,698
18510	3,673
18512	5,260
18515	1
18517	1,471
18518	3,345
18519	2,305
18603	4,548
18610	172
18612	3,650
18618	554
18621	10
18627	107
18629	4
18630	29

18634	4,156
18635	416
18640	4,328
18641	1,535
18642	1,620
18643	3,513
18644	2,507
18651	2,984
18653	42
18654	4
18655	42
18657	83
18660	2
18661	404
18701	775
18702	13,258
18704	12,140
18705	5,892
18706	5,257
18707	3,699
18708	2,782
18709	1,233
18711	30
18741	1
18762	2
18766	2
18810	-
18814	41
18817	91
18831	57
18848	2
18850	27
18921	-
18942	-
18944	3,200
18951	4,125
18955	193
18960	1,548
18962	84
18969	29
18970	165
18981	3

19235	1
19352	33
19362	169
19363	3,152
19464	415
19465	19
19475	3
19501	213
19503	116
19504	196
19505	340
19506	162
19508	2,405
19510	2,319
19511	25
19512	888
19518	3,287
19520	48
19522	1,526
19525	3,294
19526	1,075
19530	1,034
19533	912
19536	125
19539	50
19540	979
19541	138
19542	2
19543	1,074
19545	37
19551	534
19555	286
19560	1,724
19562	464
19565	1,642
19567	941
19601	8,074
19602	5,057
19604	7,113
19605	6,268
19606	9,533
19607	6,726

19608	6,257
19609	3,529
19610	5,065
19611	2,935
19612	4
Grand Total	714,946

ZIP	CLI with CAP
15437	-
15522	46
15537	-
15825	-
15864	-
16049	4
16054	-
16058	1
16213	8
16214	24
16217	-
16220	6
16225	-
16232	38
16233	17
16235	24
16239	14
16240	-
16254	42
16255	7
16260	11
16301	16
16319	13
16323	-
16326	4
16329	-
16331	5
16332	5
16334	12
16341	-
16344	-
16346	7
16353	68
16361	2
16364	8
16373	17
16374	12
16375	-
16652	102
16662	23
16673	12

16720	51
16724	5
16729	1
16730	-
16731	139
16733	-
16740	-
16743	212
16745	7
16746	73
16748	143
16749	51
16750	10
16822	-
16825	-
16830	165
16833	33
16843	5
16850	-
16855	5
16863	3
16866	39
16878	16
16881	1
16901	224
16910	2
16911	13
16912	68
16914	47
16915	180
16917	44
16918	-
16920	135
16921	24
16922	79
16923	47
16925	76
16926	4
16927	31
16928	69
16929	100
16930	11

16932	10
16933	184
16935	35
16936	56
16937	1
16939	17
16940	26
16941	3
16942	33
16943	16
16945	1
16946	113
16947	121
16948	60
16950	141
16974	-
17003	64
17004	1
17007	5
17009	6
17010	4
17011	350
17013	534
17015	99
17016	-
17018	5
17022	151
17025	212
17026	5
17028	-
17030	-
17033	90
17034	62
17036	225
17038	2
17042	589
17043	152
17044	300
17046	762
17050	177
17051	-
17052	5

17055	248
17057	249
17060	9
17065	8
17066	19
17067	91
17070	189
17072	2
17073	42
17078	139
17084	3
17087	10
17093	1
17099	17
17101	20
17102	295
17103	918
17104	1,500
17105	-
17109	415
17110	995
17111	482
17112	219
17113	754
17120	-
17177	-
17201	-
17202	12
17222	2
17233	-
17250	3
17254	-
17257	219
17260	-
17268	153
17319	15
17320	-
17325	2
17339	1
17501	-
17504	5
17505	1

17508	-
17512	409
17517	17
17519	-
17520	32
17522	36
17536	-
17537	-
17538	13
17540	67
17543	153
17545	78
17547	96
17550	11
17551	66
17552	111
17554	96
17557	55
17566	1
17567	4
17569	13
17570	-
17572	1
17578	4
17579	-
17584	13
17601	315
17602	1,384
17603	1,723
17604	-
17701	1,753
17702	217
17721	6
17724	131
17726	-
17728	20
17730	8
17735	2
17737	17
17738	-
17740	95
17745	132

17748	15
17751	5
17752	82
17754	121
17756	76
17760	9
17762	8
17764	95
17765	8
17772	10
17777	98
17779	-
17801	581
17810	-
17815	311
17821	122
17822	-
17824	-
17831	8
17833	3
17834	9
17837	22
17842	-
17844	-
17847	228
17850	21
17851	182
17856	7
17857	145
17860	-
17866	99
17868	-
17870	122
17872	222
17876	28
17886	18
17887	20
17889	-
17901	357
17921	31
17922	8
17929	2

17931	2
17936	1
17938	-
17941	-
17951	-
17954	-
17961	-
17965	31
17970	-
17972	6
17974	-
17978	-
18011	22
18013	156
18014	23
18015	1,100
18016	-
18017	444
18018	740
18020	109
18030	3
18031	97
18032	204
18034	40
18036	18
18037	76
18040	120
18042	1,567
18045	279
18049	142
18051	4
18052	342
18055	88
18058	-
18062	153
18064	82
18067	205
18068	1
18069	26
18070	-
18071	53
18072	84

18080	55
18083	1
18085	-
18087	5
18088	1
18091	7
18092	2
18101	171
18102	2,737
18103	798
18104	491
18106	17
18109	689
18195	-
18201	1,951
18202	461
18219	18
18221	3
18222	26
18223	-
18224	23
18225	8
18229	93
18235	137
18237	8
18239	4
18249	3
18251	-
18301	251
18302	-
18321	-
18326	-
18327	6
18336	7
18337	40
18343	-
18344	4
18346	-
18347	4
18349	-
18351	-
18355	-

18360	202
18366	-
18370	-
18403	180
18407	633
18410	13
18411	206
18414	38
18419	26
18421	56
18428	33
18431	204
18433	171
18434	216
18440	3
18447	372
18452	171
18466	-
18470	1
18471	10
18472	3
18473	10
18503	2
18504	1,523
18505	1,069
18507	147
18508	715
18509	594
18510	474
18512	477
18515	-
18517	184
18518	331
18519	234
18603	581
18610	4
18612	159
18618	30
18621	-
18627	2
18629	-
18630	-

18634	872
18635	47
18640	529
18641	126
18642	191
18643	354
18644	275
18651	786
18653	4
18654	-
18655	3
18657	-
18660	-
18661	28
18701	59
18702	2,821
18704	1,906
18705	985
18706	890
18707	198
18708	213
18709	196
18711	-
18741	-
18762	-
18766	-
18810	-
18814	3
18817	6
18831	4
18848	-
18850	1
18921	-
18942	-
18944	81
18951	115
18955	11
18960	53
18962	3
18969	-
18970	3
18981	-

19235	-
19352	-
19362	5
19363	158
19464	7
19465	-
19475	-
19501	2
19503	1
19504	3
19505	4
19506	-
19508	148
19510	71
19511	-
19512	31
19518	72
19520	-
19522	71
19525	61
19526	80
19530	18
19533	20
19536	7
19539	1
19540	53
19541	4
19542	-
19543	11
19545	1
19551	32
19555	14
19560	127
19562	17
19565	80
19567	43
19601	1,734
19602	1,287
19604	1,631
19605	471
19606	695
19607	391

19608	252
19609	228
19610	141
19611	318
19612	-
Total	**66,834**

ZIP	CLI without CAP
15437	-
15522	23
15537	-
15825	-
15864	-
16049	2
16054	-
16058	-
16213	3
16214	12
16217	-
16220	3
16225	-
16232	28
16233	9
16235	15
16239	12
16240	-
16254	30
16255	6
16260	4
16301	14
16319	6
16323	-
16326	2
16329	-
16331	3
16332	3
16334	7
16341	-
16344	-
16346	6
16353	45
16361	1
16364	4
16373	12
16374	7
16375	-
16652	70
16662	16
16673	11

16720	33
16724	5
16729	-
16730	-
16731	93
16733	-
16740	-
16743	133
16745	2
16746	49
16748	102
16749	27
16750	5
16822	-
16825	-
16830	95
16833	14
16843	2
16850	-
16855	3
16863	3
16866	18
16878	12
16881	-
16901	159
16910	2
16911	11
16912	52
16914	26
16915	110
16917	33
16918	-
16920	87
16921	13
16922	51
16923	26
16925	57
16926	2
16927	21
16928	51
16929	66
16930	6

16932	8
16933	126
16935	24
16936	37
16937	-
16939	13
16940	12
16941	1
16942	26
16943	11
16945	1
16946	76
16947	86
16948	33
16950	84
16974	-
17003	46
17004	1
17007	5
17009	2
17010	3
17011	248
17013	384
17015	73
17016	-
17018	3
17022	123
17025	161
17026	3
17028	-
17030	-
17033	63
17034	43
17036	135
17038	2
17042	372
17043	105
17044	214
17046	416
17050	125
17051	-
17052	3

17055	184
17057	185
17060	4
17065	7
17066	12
17067	69
17070	145
17072	1
17073	29
17078	107
17084	-
17087	7
17093	1
17099	12
17101	13
17102	163
17103	523
17104	830
17105	-
17109	316
17110	582
17111	350
17112	171
17113	442
17120	-
17177	-
17201	-
17202	10
17222	2
17233	-
17250	3
17254	-
17257	157
17260	-
17268	109
17319	10
17320	-
17325	1
17339	1
17501	-
17504	3
17505	1

17508	-
17512	254
17517	17
17519	-
17520	24
17522	30
17536	-
17537	-
17538	11
17540	49
17543	122
17545	58
17547	82
17550	9
17551	51
17552	86
17554	70
17557	45
17566	1
17567	3
17569	9
17570	-
17572	1
17578	3
17579	-
17584	11
17601	244
17602	849
17603	1,085
17604	-
17701	1,025
17702	150
17721	3
17724	82
17726	-
17728	12
17730	5
17735	2
17737	13
17738	-
17740	64
17745	86

17748	11
17751	4
17752	55
17754	91
17756	54
17760	5
17762	7
17764	60
17765	6
17772	7
17777	66
17779	-
17801	359
17810	-
17815	208
17821	92
17822	-
17824	-
17831	7
17833	3
17834	5
17837	12
17842	-
17844	-
17847	162
17850	15
17851	113
17856	3
17857	93
17860	-
17866	66
17868	-
17870	72
17872	131
17876	17
17886	7
17887	17
17889	-
17901	227
17921	17
17922	6
17929	1

17931	2
17936	1
17938	-
17941	-
17951	-
17954	-
17961	-
17965	15
17970	-
17972	5
17974	-
17978	-
18011	20
18013	119
18014	14
18015	700
18016	-
18017	305
18018	501
18020	83
18030	2
18031	70
18032	134
18034	25
18036	11
18037	42
18040	87
18042	908
18045	186
18049	101
18051	4
18052	195
18055	59
18058	-
18062	129
18064	59
18067	146
18068	-
18069	17
18070	-
18071	35
18072	64

18080	36
18083	1
18085	-
18087	2
18088	1
18091	5
18092	2
18101	94
18102	1,580
18103	521
18104	319
18106	13
18109	383
18195	-
18201	1,075
18202	268
18219	16
18221	2
18222	16
18223	-
18224	14
18225	6
18229	65
18235	94
18237	6
18239	3
18249	2
18251	-
18301	198
18302	-
18321	-
18326	-
18327	5
18336	4
18337	29
18343	-
18344	4
18346	-
18347	2
18349	-
18351	-
18355	-

18360	162
18366	-
18370	-
18403	117
18407	392
18410	9
18411	148
18414	26
18419	22
18421	39
18428	20
18431	123
18433	114
18434	120
18440	2
18447	219
18452	115
18466	-
18470	-
18471	6
18472	1
18473	5
18503	-
18504	904
18505	643
18507	87
18508	438
18509	370
18510	279
18512	298
18515	-
18517	106
18518	212
18519	144
18603	377
18610	4
18612	111
18618	18
18621	-
18627	1
18629	-
18630	-

18634	466
18635	36
18640	333
18641	90
18642	127
18643	228
18644	157
18651	379
18653	4
18654	-
18655	1
18657	-
18660	-
18661	20
18701	29
18702	1,577
18704	1,020
18705	528
18706	512
18707	117
18708	115
18709	107
18711	-
18741	-
18762	-
18766	-
18810	-
18814	2
18817	4
18831	3
18848	-
18850	1
18921	-
18942	-
18944	55
18951	87
18955	8
18960	39
18962	3
18969	-
18970	2
18981	-

19235	-
19352	-
19362	5
19363	111
19464	7
19465	-
19475	-
19501	1
19503	1
19504	3
19505	3
19506	-
19508	118
19510	60
19511	-
19512	22
19518	63
19520	-
19522	58
19525	52
19526	54
19530	12
19533	19
19536	6
19539	1
19540	35
19541	3
19542	-
19543	9
19545	1
19551	19
19555	10
19560	88
19562	13
19565	54
19567	33
19601	1,016
19602	777
19604	1,024
19605	314
19606	508
19607	269

19608	177
19609	159
19610	105
19611	204
19612	-
Total	**41,697**

ZIP	CAP
15437	-
15522	23
15537	-
15825	-
15864	-
16049	2
16054	-
16058	1
16213	5
16214	12
16217	-
16220	3
16225	-
16232	10
16233	8
16235	9
16239	2
16240	-
16254	12
16255	1
16260	7
16301	2
16319	7
16323	-
16326	2
16329	-
16331	2
16332	2
16334	5
16341	-
16344	-
16346	1
16353	23
16361	1
16364	4
16373	5
16374	5
16375	-
16652	32
16662	7
16673	1

16720	18
16724	-
16729	1
16730	-
16731	46
16733	-
16740	-
16743	79
16745	5
16746	24
16748	41
16749	24
16750	5
16822	-
16825	-
16830	70
16833	19
16843	3
16850	-
16855	2
16863	-
16866	21
16878	4
16881	1
16901	65
16910	-
16911	2
16912	16
16914	21
16915	70
16917	11
16918	-
16920	48
16921	11
16922	28
16923	21
16925	19
16926	2
16927	10
16928	18
16929	34
16930	5

16932	2
16933	58
16935	11
16936	19
16937	1
16939	4
16940	14
16941	2
16942	7
16943	5
16945	-
16946	37
16947	35
16948	27
16950	57
16974	-
17003	18
17004	-
17007	-
17009	4
17010	1
17011	102
17013	150
17015	26
17016	-
17018	2
17022	28
17025	51
17026	2
17028	-
17030	-
17033	27
17034	19
17036	90
17038	-
17042	217
17043	47
17044	86
17046	346
17050	52
17051	-
17052	2

17055	64
17057	64
17060	5
17065	1
17066	7
17067	22
17070	44
17072	1
17073	13
17078	32
17084	3
17087	3
17093	-
17099	5
17101	7
17102	132
17103	395
17104	670
17105	-
17109	99
17110	413
17111	132
17112	48
17113	312
17120	-
17177	-
17201	-
17202	2
17222	-
17233	-
17250	-
17254	-
17257	62
17260	-
17268	44
17319	5
17320	-
17325	1
17339	-
17501	-
17504	2
17505	-

17508	-
17512	155
17517	-
17519	-
17520	8
17522	6
17536	-
17537	-
17538	2
17540	18
17543	31
17545	20
17547	14
17550	2
17551	15
17552	25
17554	26
17557	10
17566	-
17567	1
17569	4
17570	-
17572	-
17578	1
17579	-
17584	2
17601	71
17602	535
17603	638
17604	-
17701	728
17702	67
17721	3
17724	49
17726	-
17728	8
17730	3
17735	-
17737	4
17738	-
17740	31
17745	46

17748	4
17751	1
17752	27
17754	30
17756	22
17760	4
17762	1
17764	35
17765	2
17772	3
17777	32
17779	-
17801	222
17810	-
17815	103
17821	30
17822	-
17824	-
17831	1
17833	-
17834	4
17837	10
17842	-
17844	-
17847	66
17850	6
17851	69
17856	4
17857	52
17860	-
17866	33
17868	-
17870	50
17872	91
17876	11
17886	11
17887	3
17889	-
17901	130
17921	14
17922	2
17929	1

17931	-
17936	-
17938	-
17941	-
17951	-
17954	-
17961	-
17965	16
17970	-
17972	1
17974	-
17978	-
18011	2
18013	37
18014	9
18015	400
18016	-
18017	139
18018	239
18020	26
18030	1
18031	27
18032	70
18034	15
18036	7
18037	34
18040	33
18042	659
18045	93
18049	41
18051	-
18052	147
18055	29
18058	-
18062	24
18064	23
18067	59
18068	1
18069	9
18070	-
18071	18
18072	20

18080	19
18083	-
18085	-
18087	3
18088	-
18091	2
18092	-
18101	77
18102	1,157
18103	277
18104	172
18106	4
18109	306
18195	-
18201	876
18202	193
18219	2
18221	1
18222	10
18223	-
18224	9
18225	2
18229	28
18235	43
18237	2
18239	1
18249	1
18251	-
18301	53
18302	-
18321	-
18326	-
18327	1
18336	3
18337	11
18343	-
18344	-
18346	-
18347	2
18349	-
18351	-
18355	-

18360	40
18366	-
18370	-
18403	63
18407	241
18410	4
18411	58
18414	12
18419	4
18421	17
18428	13
18431	81
18433	57
18434	96
18440	1
18447	153
18452	56
18466	-
18470	1
18471	4
18472	2
18473	5
18503	2
18504	619
18505	426
18507	60
18508	277
18509	224
18510	195
18512	179
18515	-
18517	78
18518	119
18519	90
18603	204
18610	-
18612	48
18618	12
18621	-
18627	1
18629	-
18630	-

18634	406
18635	11
18640	196
18641	36
18642	64
18643	126
18644	118
18651	407
18653	-
18654	-
18655	2
18657	-
18660	-
18661	8
18701	30
18702	1,244
18704	886
18705	457
18706	378
18707	81
18708	98
18709	89
18711	-
18741	-
18762	-
18766	-
18810	-
18814	1
18817	2
18831	1
18848	-
18850	-
18921	-
18942	-
18944	26
18951	28
18955	3
18960	14
18962	-
18969	-
18970	1
18981	-

19235	-
19352	-
19362	-
19363	47
19464	-
19465	-
19475	-
19501	1
19503	-
19504	-
19505	1
19506	-
19508	30
19510	11
19511	-
19512	9
19518	9
19520	-
19522	13
19525	9
19526	26
19530	6
19533	1
19536	1
19539	-
19540	18
19541	1
19542	-
19543	2
19545	-
19551	13
19555	4
19560	39
19562	4
19565	26
19567	10
19601	718
19602	510
19604	607
19605	157
19606	187
19607	122

19608	75
19609	69
19610	36
19611	114
19612	-
Total	**25,137**

OCA-4-6

Request:

In Excel format, for each month for the most recent 36 months available, please provide the mean usage for:

a. Residential customers as a whole;

b. Confirmed low-income customers (without CAP participants);

c. Confirmed low-income customers (with CAP participants);

d. CAP participants.

Response:

a. Please see Attachment OCA-4-6.

b. Please see the response to OCA-4-6(a).

c. Please see the response to OCA-4-6(a).

d. Please see the response to OCA-4-6(a).

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided in parts (b) and (c) included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

Confirmed Low Income status for the above responses is based on a snapshot of customers as of November 30, 2025.

Prepared by or under the supervision of: Brian J. Meilinger

Month & Year	All Residential Customers	Confirmed Low Income (Excluding CAP)	Confirmed Low Income	CAP Customers
Jan-23	138	158	164	180
Feb-23	127	147	153	168
Mar-23	112	129	136	150
Apr-23	71	82	87	101
May-23	38	43	47	55
Jun-23	21	22	23	26
Jul-23	16	17	17	18
Aug-23	14	15	15	16
Sep-23	15	16	17	17
Oct-23	23	26	28	32
Nov-23	57	65	69	79
Dec-23	111	127	134	147
Jan-24	134	151	159	175
Feb-24	130	149	157	172
Mar-24	102	118	124	138
Apr-24	77	89	96	108
May-24	33	37	41	47
Jun-24	19	20	21	23
Jul-24	14	15	16	16
Aug-24	14	14	15	16
Sep-24	16	16	17	18
Oct-24	21	23	25	28
Nov-24	45	53	56	62
Dec-24	116	132	139	153
Jan-25	162	185	194	209
Feb-25	169	194	202	220
Mar-25	116	137	145	158
Apr-25	69	81	86	97
May-25	33	38	41	46
Jun-25	23	25	27	31
Jul-25	15	16	16	17
Aug-25	14	14	15	16
Sep-25	15	16	17	18
Oct-25	20	23	24	27
Nov-25	60	68	73	83
Dec-25	131	148	156	170
Jan-26	166	189	199	215

OCA-4-16

Request:

For each zip code identified in response to Question 3 above, in Excel format, for the most recent 36 months available, please provide:

a. The number of nonpayment disconnections of residential customers;
b. The number of nonpayment disconnections of Confirmed Low-Income customers (without CAP);
c. The number of nonpayment disconnection notices provided to residential customers;
d. The number of nonpayment disconnection notices provided to Confirmed Low-Income customers (without CAP)
e. The number of reconnections after a nonpayment disconnection for residential customers.
f. The number of reconnections after a nonpayment disconnection for Confirmed Low-Income customers (without CAP).

Response:

a. Please see Attachment OCA-4-16(a).

b. Please see Attachment OCA-4-16(b).

c. Please see Attachment OCA-4-16(c). UGI Gas does not track this data according to zip codes.

d. Please see Attachment OCA-4-16(d). UGI Gas does not track this data according to zip codes.

e. Please see Attachment OCA-4-16(e).

f. Please see Attachment OCA-4-16(f).

Please note, consistent with 52 Pa. Code § 62.2, confirmed low-income customers provided in parts (b), (d) and (f) included both income-verified and self-certified customers with income at or below 150% of Federal Poverty Income Guidelines.

OCA-4-16 (Continued)

Confirmed Low Income status for the above responses is based on a snapshot of customers as of November 30, 2025.

Prepared by or under the supervision of: Daniel V. Adamo

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR CONFIRMED LOW-INCOME RESIDENTIAL CUSTOMERS (without CAP)
FOR CALENDAR YEAR 2023

Zip Code	January	February	March	April	May	June	July	August	September	October	November	December	Zip Code Total
15522	0	0	0	0	1	0	0	0	0	1	0	0	2
16214	0	0	0	0	0	1	0	1	0	0	0	0	2
16232	0	0	0	2	0	0	1	1	0	0	0	0	4
16235	0	0	0	0	1	1	0	0	0	1	0	0	3
16254	0	0	0	1	0	0	1	1	0	1	1	0	6
16255	0	0	0	0	0	1	0	0	0	0	0	0	1
16301	0	0	0	0	1	0	1	0	0	0	0	0	2
16319	0	0	0	0	0	0	0	0	0	0	1	0	1
16326	0	0	0	1	0	0	0	0	0	0	0	0	1
16332	0	0	0	0	0	0	0	1	0	0	0	0	1
16334	0	0	0	0	0	0	0	0	0	1	0	0	1
16353	0	0	0	3	1	4	1	2	4	0	1	0	16
16364	0	0	0	0	1	0	1	0	0	0	0	0	2
16373	0	0	0	1	0	0	0	1	0	1	0	0	4
16374	0	0	0	1	1	0	0	0	0	0	0	0	2
16652	0	0	0	4	2	4	2	2	2	1	0	0	17
16673	0	0	0	0	0	0	1	0	0	0	0	0	1
16720	0	0	0	3	1	0	1	0	0	1	0	0	6
16724	0	0	0	0	0	0	0	0	0	0	1	0	1
16731	0	0	0	2	1	1	2	6	2	2	0	0	16
16743	0	0	0	3	1	6	5	7	2	1	1	0	26
16746	0	0	0	1	1	2	0	0	0	0	0	0	4
16748	0	0	0	5	0	2	1	1	0	0	1	0	10
16749	0	0	0	0	0	1	2	1	1	0	0	0	5
16750	0	0	0	0	0	0	0	0	1	0	0	0	1
16830	0	0	0	0	4	5	2	2	1	1	0	0	15
16833	0	0	0	2	0	0	0	0	1	1	1	0	5

16855	0	0	0	0	0	0	0	1	0	0	0	0	1
16866	0	0	0	1	0	0	1	0	0	1	0	0	3
16901	0	0	0	7	0	5	2	0	2	1	2	0	19
16911	0	0	0	1	0	1	0	0	0	0	0	0	2
16912	0	0	0	4	1	3	1	1	1	2	1	0	14
16914	0	0	0	0	0	1	0	3	1	0	0	0	5
16915	0	0	0	2	0	3	0	1	1	0	1	0	8
16917	0	0	0	2	1	2	0	0	0	1	1	0	7
16920	0	0	0	2	0	0	0	1	1	0	1	0	6
16922	0	0	0	4	0	1	0	2	0	0	1	0	8
16923	0	0	0	0	1	1	1	0	0	0	0	0	3
16925	0	0	0	2	0	0	1	1	0	2	0	0	6
16927	0	0	0	0	1	0	0	2	0	1	0	0	4
16928	0	0	0	0	0	0	0	1	0	0	0	0	1
16929	0	0	0	3	0	0	3	3	3	2	1	0	15
16930	0	0	0	0	0	0	1	0	0	0	1	0	2
16932	0	0	0	0	0	0	1	0	0	0	0	0	1
16933	0	0	0	4	2	3	1	2	2	2	1	0	17
16936	0	0	0	1	0	0	1	0	0	0	0	0	2
16939	0	0	0	0	1	0	2	0	1	0	0	0	4
16940	0	0	0	0	0	0	1	2	0	1	0	0	4
16942	0	0	0	1	0	0	1	0	0	0	0	0	2
16946	0	0	0	2	0	4	1	2	3	0	0	0	12
16947	0	0	0	3	0	3	1	4	1	2	0	0	14
16948	0	0	0	2	1	0	0	0	0	0	0	0	3
16950	0	0	0	2	0	1	1	0	0	0	0	0	4
17003	0	0	0	3	1	0	0	0	0	0	1	0	5
17009	0	0	0	0	2	1	1	0	1	0	0	0	5
17011	0	0	0	4	0	5	3	6	9	5	1	0	33
17013	0	0	0	7	5	2	7	11	6	7	5	0	50
17015	0	0	0	0	1	0	0	2	1	0	1	0	5
17018	0	0	0	0	0	0	0	1	1	0	0	0	2
17022	0	0	0	2	3	2	0	2	0	2	1	0	12
17025	0	0	0	1	2	1	3	1	1	3	2	0	15
17026	0	0	0	0	0	0	1	0	1	0	0	0	2
17033	0	0	0	2	0	1	2	1	0	1	1	0	8

17034	0	0	0	0	1	0	2	1	0	3	1	0	8
17036	0	0	0	6	4	3	1	4	6	2	0	0	26
17042	0	0	0	2	6	8	3	14	5	5	1	0	44
17043	0	0	0	6	1	2	0	2	0	1	1	0	13
17044	0	0	0	5	3	4	3	4	3	3	6	0	31
17046	0	0	0	12	8	2	6	17	7	1	3	0	58
17050	0	0	0	3	0	1	2	4	2	1	2	0	15
17055	0	0	0	6	6	2	2	4	7	7	1	0	35
17057	0	0	0	3	3	6	1	2	1	8	4	0	28
17060	0	0	0	0	0	1	0	0	0	0	0	0	1
17065	0	0	0	0	0	0	0	0	1	0	0	0	1
17066	0	0	0	1	0	0	0	0	0	0	0	0	1
17067	0	0	0	0	0	2	0	1	2	1	0	0	6
17070	0	0	0	1	2	2	6	4	3	0	1	0	19
17072	0	0	0	0	0	0	0	0	1	0	0	0	1
17073	0	0	0	1	0	1	4	0	0	0	0	0	6
17078	0	0	0	4	0	1	4	1	3	3	1	0	17
17087	0	0	0	1	0	0	0	0	2	0	0	0	3
17099	0	0	0	1	0	0	0	1	0	0	0	0	2
17101	0	0	0	0	0	1	0	1	0	0	0	0	2
17102	0	0	0	12	0	4	1	9	0	7	0	0	33
17103	0	0	0	21	10	21	1	19	10	25	4	0	113
17104	0	0	0	37	27	20	17	32	15	27	13	0	190
17109	0	0	0	7	9	4	1	14	6	5	2	0	48
17110	0	0	0	18	12	26	14	18	19	21	1	0	132
17111	0	0	0	8	9	8	6	1	7	6	8	0	54
17112	0	0	0	1	3	2	2	2	8	5	0	0	23
17113	0	0	0	15	9	7	7	14	7	14	7	0	81
17202	0	0	0	1	0	0	0	0	0	1	0	0	2
17257	0	0	0	7	2	2	1	2	1	7	1	0	23
17268	0	0	0	7	4	2	4	6	3	4	2	0	32
17319	0	0	0	0	1	0	0	0	1	0	0	0	2
17504	0	0	0	0	0	0	0	1	0	0	0	0	1
17512	0	0	0	7	4	3	1	7	6	6	3	0	37
17517	0	0	0	0	0	2	0	0	0	1	1	0	4
17520	0	0	0	0	1	0	0	1	3	1	0	0	6

17538	0	0	0	0	1	0	0	0	0	0	0	0	1
17540	0	0	0	5	1	0	0	1	1	1	1	0	10
17543	0	0	0	5	0	0	4	1	4	3	2	0	19
17545	0	0	0	2	0	0	1	0	4	4	1	0	12
17547	0	0	0	0	3	2	1	2	1	3	0	0	12
17550	0	0	0	0	1	0	0	0	1	0	0	0	2
17551	0	0	0	0	2	0	0	2	1	3	1	0	10
17552	0	0	0	0	1	0	1	4	3	0	2	0	11
17554	0	0	0	2	1	0	0	5	1	0	0	0	9
17557	0	0	0	3	1	0	2	4	3	1	2	0	16
17569	0	0	0	0	2	0	1	0	1	1	0	0	5
17578	0	0	0	1	0	0	0	0	1	0	0	0	2
17584	0	0	0	0	0	0	0	1	0	1	0	0	2
17601	0	0	0	4	2	3	4	5	7	3	4	0	33
17602	0	0	0	23	16	10	24	23	32	15	6	0	149
17603	0	0	0	21	33	14	10	47	32	22	12	0	191
17701	0	0	0	46	28	22	35	29	17	15	22	0	216
17702	0	0	0	4	5	6	4	2	3	4	8	0	36
17721	0	0	0	0	0	0	1	0	0	0	0	0	1
17724	0	0	0	3	2	2	4	2	0	2	3	0	18
17737	0	0	0	2	1	0	2	1	0	0	0	0	6
17740	0	0	0	5	0	4	2	2	0	3	0	0	16
17745	0	0	0	3	2	5	4	1	1	1	2	0	19
17751	0	0	0	0	0	0	1	0	0	0	0	0	1
17752	0	0	0	1	3	0	0	1	2	1	1	0	9
17754	0	0	0	8	5	3	0	3	1	0	3	0	23
17756	0	0	0	2	3	1	0	0	0	1	2	0	10
17762	0	0	0	0	0	0	0	0	1	0	0	0	1
17764	0	0	0	1	0	0	2	1	0	0	1	0	5
17772	0	0	0	1	0	0	0	0	1	0	0	0	2
17777	0	0	0	3	1	1	0	1	3	1	0	0	10
17801	0	0	0	14	11	6	16	8	9	3	2	0	69
17815	0	0	0	10	5	5	7	9	4	1	8	0	49
17821	0	0	0	5	4	0	2	4	0	1	0	0	16
17834	0	0	0	0	1	0	0	0	0	0	0	0	1
17837	0	0	0	2	0	0	1	0	0	0	0	0	3

17847	0	0	0	10	0	2	2	2	7	2	1	0	26
17850	0	0	0	3	0	1	1	1	0	0	0	0	6
17851	0	0	0	8	1	3	1	6	0	2	1	0	22
17857	0	0	0	9	1	1	1	3	2	2	0	0	19
17866	0	0	0	3	2	1	2	3	3	0	0	0	14
17870	0	0	0	1	2	0	1	1	0	1	0	0	6
17872	0	0	0	7	2	2	2	3	2	0	3	0	21
17876	0	0	0	0	1	0	0	0	0	0	0	0	1
17886	0	0	0	0	0	1	1	0	0	0	0	0	2
17887	0	0	0	0	1	0	0	0	0	0	0	0	1
17901	0	0	0	10	5	12	5	3	1	4	1	0	42
17921	0	0	0	0	1	2	0	2	0	0	0	0	5
17922	0	0	0	1	1	0	1	1	0	0	0	0	4
17931	0	0	0	1	0	0	0	0	0	1	0	0	2
17936	0	0	0	0	0	1	0	0	1	0	0	0	2
17965	0	0	0	1	0	0	1	1	0	0	0	0	3
18011	0	0	0	1	1	0	1	0	0	0	1	0	4
18013	0	0	0	2	1	5	7	2	2	2	0	0	21
18014	0	0	0	1	0	0	2	1	0	0	0	0	4
18015	0	0	0	13	12	25	9	21	25	12	20	0	140
18017	0	0	0	3	6	5	4	5	11	2	8	0	44
18018	0	0	0	13	8	6	9	17	14	3	17	0	87
18020	0	0	0	2	4	0	0	2	3	1	1	0	13
18031	0	0	0	0	1	2	0	1	2	1	0	0	7
18032	0	0	0	2	1	2	5	1	0	1	3	0	15
18034	0	0	0	0	1	0	0	1	0	0	2	0	5
18037	0	0	0	0	1	2	1	2	0	0	0	0	6
18040	0	0	0	2	2	1	0	2	3	2	1	0	13
18042	0	0	0	15	7	13	24	34	15	22	20	0	151
18045	0	0	0	5	1	1	4	6	1	2	4	0	24
18049	0	0	0	2	0	2	2	3	2	2	2	0	15
18052	0	0	0	6	3	6	4	10	1	5	6	0	42
18055	0	0	0	1	1	0	0	2	0	0	3	0	7
18062	0	0	0	2	0	2	4	4	4	1	3	0	20
18064	0	0	0	1	0	0	0	2	0	2	1	0	6
18067	0	0	0	7	2	1	4	14	1	2	3	0	34

18069	0	0	0	0	1	0	1	4	1	0	1	0	8
18071	0	0	0	0	1	0	1	1	0	1	0	0	4
18072	0	0	0	0	1	1	2	2	1	2	0	0	9
18080	0	0	0	1	2	0	1	0	0	0	0	0	4
18091	0	0	0	0	1	0	0	0	0	0	0	0	1
18101	0	0	0	1	2	2	5	0	3	1	1	0	15
18102	0	0	0	46	36	45	47	49	46	35	28	0	332
18103	0	0	0	5	7	8	5	9	19	8	15	0	78
18104	0	0	0	4	5	7	11	7	6	11	7	0	59
18106	0	0	0	0	0	0	1	1	0	0	0	0	2
18109	0	0	0	2	7	4	10	9	19	2	12	0	66
18201	0	0	0	65	41	53	24	61	17	18	43	0	327
18202	0	0	0	5	7	13	9	7	1	8	10	0	60
18219	0	0	0	1	0	0	0	1	0	1	0	0	3
18222	0	0	0	0	0	0	1	0	0	2	0	0	3
18229	0	0	0	1	1	5	2	2	0	1	0	0	13
18235	0	0	0	2	0	3	2	4	1	1	1	0	14
18301	0	0	0	13	3	9	8	5	1	3	7	0	49
18327	0	0	0	0	0	0	0	1	0	0	0	0	1
18337	0	0	0	0	0	0	0	2	3	0	0	0	5
18344	0	0	0	0	0	0	0	0	0	1	0	0	1
18360	0	0	0	6	2	3	5	6	3	1	5	0	32
18403	0	0	0	4	0	2	2	3	4	0	3	0	18
18407	0	0	0	6	18	6	3	20	8	1	8	0	71
18411	0	0	0	7	4	1	4	7	3	2	2	0	30
18414	0	0	0	2	2	3	1	1	1	0	0	0	10
18419	0	0	0	1	0	1	0	0	0	0	0	0	2
18421	0	0	0	0	2	0	1	2	0	0	1	0	6
18428	0	0	0	1	1	0	1	0	0	0	1	0	4
18431	0	0	0	2	6	2	1	6	2	5	6	0	30
18433	0	0	0	3	1	2	4	5	1	4	3	0	23
18434	0	0	0	3	1	3	3	5	3	1	1	0	20
18447	0	0	0	10	12	2	9	10	2	1	3	0	50
18452	0	0	0	3	6	3	2	5	2	0	2	0	23
18473	0	0	0	0	0	0	0	0	1	0	0	0	1
18504	0	0	0	23	27	34	16	40	22	24	8	0	196

18505	0	0	0	19	25	18	13	26	19	10	9	0	139
18507	0	0	0	1	4	3	3	9	2	0	6	0	28
18508	0	0	0	24	7	19	3	15	8	12	4	0	93
18509	0	0	0	20	10	10	6	14	8	11	4	0	83
18510	0	0	0	3	7	7	8	9	8	4	7	0	54
18512	0	0	0	9	6	13	9	15	5	5	5	0	67
18517	0	0	0	4	1	0	5	5	2	0	0	0	17
18518	0	0	0	5	6	7	4	2	7	0	3	0	34
18519	0	0	0	5	4	5	3	11	2	2	5	0	37
18603	0	0	0	16	4	4	7	14	4	6	3	0	60
18610	0	0	0	1	1	0	0	0	0	0	0	0	2
18612	0	0	0	2	2	2	1	2	1	1	2	0	13
18634	0	0	0	1	6	13	12	4	5	6	4	0	52
18635	0	0	0	1	0	2	2	0	0	1	0	0	6
18640	0	0	0	19	4	7	9	17	4	1	5	0	68
18641	0	0	0	1	1	3	1	5	2	0	2	0	15
18642	0	0	0	2	5	3	8	2	3	0	6	0	29
18643	0	0	0	9	3	8	5	9	5	5	3	0	47
18644	0	0	0	2	1	2	4	3	2	0	3	0	17
18651	0	0	0	12	4	5	8	5	6	5	3	0	48
18653	0	0	0	0	0	0	0	0	1	0	0	0	1
18661	0	0	0	0	0	0	0	1	0	0	0	0	1
18701	0	0	0	2	0	1	0	1	0	0	2	0	6
18702	0	0	0	40	47	47	55	40	54	24	33	0	343
18704	0	0	0	14	12	17	16	27	22	5	9	0	122
18705	0	0	0	16	10	19	18	14	12	6	16	0	112
18706	0	0	0	5	14	13	4	15	4	9	4	0	68
18707	0	0	0	2	5	4	3	2	4	1	1	0	22
18708	0	0	0	0	2	0	2	4	1	0	2	0	12
18709	0	0	0	2	1	2	2	2	1	0	2	0	12
18831	0	0	0	0	0	0	0	0	0	0	1	0	1
18850	0	0	0	1	0	0	0	0	0	0	0	0	1
18944	0	0	0	0	1	0	0	1	0	0	2	0	4
18951	0	0	0	1	1	1	2	3	1	1	4	0	15
18955	0	0	0	0	0	1	0	1	0	0	0	0	2
18960	0	0	0	0	0	0	0	1	0	0	0	0	1

19362	0	0	0	1	0	0	0	1	0	0	0	0	2
19363	0	0	0	10	1	7	2	7	2	2	2	0	33
19501	0	0	0	1	0	0	0	0	0	0	0	0	1
19508	0	0	0	1	0	3	1	3	6	1	3	0	18
19510	0	0	0	0	0	2	0	1	1	0	0	0	4
19512	0	0	0	0	2	1	0	1	0	0	0	0	4
19518	0	0	0	0	2	3	1	1	2	1	1	0	11
19522	0	0	0	0	2	1	0	4	0	0	0	0	7
19525	0	0	0	1	0	3	0	3	2	1	0	0	10
19526	0	0	0	2	0	0	1	1	0	0	0	0	4
19530	0	0	0	0	0	0	0	1	1	1	0	0	3
19533	0	0	0	1	0	0	0	0	0	0	0	0	1
19539	0	0	0	0	0	1	0	0	0	0	0	0	1
19540	0	0	0	2	1	1	0	0	1	0	2	0	7
19543	0	0	0	0	0	0	0	0	0	0	1	0	1
19551	0	0	0	1	0	1	0	1	2	0	0	0	5
19560	0	0	0	2	1	0	1	0	1	0	0	0	5
19565	0	0	0	1	3	0	3	0	0	0	4	0	11
19567	0	0	0	0	1	1	0	0	1	0	0	0	3
19601	0	0	0	9	15	22	19	27	17	12	14	0	138
19602	0	0	0	10	9	3	9	14	14	8	5	0	75
19604	0	0	0	16	10	19	27	15	20	9	12	0	131
19605	0	0	0	5	1	4	3	4	5	3	6	0	32
19606	0	0	0	6	7	13	9	3	8	8	12	0	66
19607	0	0	0	7	4	5	5	6	4	6	4	0	41
19608	0	0	0	2	4	1	4	0	5	1	5	0	22
19609	0	0	0	1	1	7	3	4	5	4	0	0	25
19610	0	0	0	2	3	0	3	5	0	1	3	0	17
19611	0	0	0	2	2	2	3	2	1	1	1	0	14
Grand Total	**0**	**0**	**0**	**1131**	**827**	**936**	**863**	**1235**	**874**	**680**	**669**	**0**	**7280**

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR CONFIRMED LOW-INCOME RESIDENTIAL CUSTOMERS (without CAP)
FOR CALENDAR YEAR 2024

Zip Code	January	February	March	April	May	June	July	August	September	October	November	December	Zip Code Total
15522	0	0	0	0	0	1	1	0	0	1	1	0	4
16213	0	0	0	0	0	1	0	0	0	0	0	0	1
16214	0	0	0	0	1	0	0	0	0	1	0	0	2
16233	0	0	0	0	0	1	0	1	0	0	0	0	2
16235	0	0	0	0	0	0	2	0	0	1	0	0	3
16239	0	0	0	0	1	0	0	0	0	0	0	0	1
16254	0	0	0	2	1	0	1	0	0	0	1	0	5
16255	0	0	0	0	0	0	0	0	0	1	0	0	1
16260	0	0	0	0	1	0	0	0	0	0	0	0	1
16301	0	0	0	0	0	0	0	1	1	0	0	0	2
16319	0	0	0	0	1	0	0	0	0	0	0	0	1
16326	0	0	0	0	0	0	0	0	1	0	0	0	1
16332	0	0	0	0	1	0	0	0	0	0	0	0	1
16353	0	0	0	2	1	1	5	1	2	5	2	0	19
16364	0	0	0	0	0	0	0	1	0	0	0	0	1
16373	0	0	0	0	1	0	0	0	0	0	0	0	1
16374	0	0	0	0	0	0	1	0	0	0	0	0	1
16652	0	0	0	4	4	4	1	2	0	1	0	0	17
16673	0	0	0	2	2	1	0	2	0	0	0	0	7
16720	0	0	0	1	0	0	1	0	0	0	0	0	2
16724	0	0	0	0	0	0	1	1	0	0	0	0	2
16731	0	0	0	3	3	3	3	7	2	2	0	0	23
16743	0	0	0	3	6	6	1	8	0	6	1	0	31
16746	0	0	0	1	1	2	0	1	0	3	0	0	9
16748	0	0	0	4	1	0	5	3	1	3	1	0	18
16749	0	0	0	3	0	0	3	0	0	2	0	0	8
16830	0	0	0	2	4	3	1	2	1	1	0	0	14

16866	0	0	0	0	1	2	0	1	0	0	0	0	4
16878	0	0	0	0	0	0	1	0	0	0	1	0	2
16901	0	0	0	6	2	6	4	3	0	2	0	0	23
16911	0	0	0	0	1	0	0	0	0	0	0	0	1
16912	0	0	0	2	1	0	1	2	0	1	0	0	7
16914	0	0	0	1	1	0	1	2	1	0	0	0	6
16915	0	0	0	1	0	1	3	3	3	5	0	0	16
16917	0	0	0	3	1	0	0	2	1	0	0	0	7
16920	0	0	0	0	2	0	3	0	0	1	0	0	6
16921	0	0	0	0	0	1	0	0	1	0	0	0	2
16922	0	0	0	1	1	1	0	0	2	0	0	0	5
16923	0	0	0	1	1	1	0	1	0	1	0	0	5
16925	0	0	0	1	1	1	3	3	2	0	1	0	12
16927	0	0	0	1	0	0	0	1	0	0	0	0	2
16928	0	0	0	1	0	1	0	0	2	0	0	0	4
16929	0	0	0	2	3	2	2	2	1	0	0	0	12
16932	0	0	0	0	1	1	0	0	0	0	0	0	2
16933	0	0	0	2	4	1	2	1	2	0	1	0	13
16936	0	0	0	1	1	0	0	0	0	0	0	0	2
16939	0	0	0	1	2	1	0	1	0	0	0	0	5
16940	0	0	0	0	0	0	0	0	0	1	0	0	1
16942	0	0	0	0	0	2	0	0	0	0	1	0	3
16946	0	0	0	4	1	1	1	0	3	1	0	0	11
16947	0	0	0	2	4	6	3	3	2	2	0	0	22
16948	0	0	0	5	1	1	1	1	1	0	0	0	10
16950	0	0	0	1	0	1	0	2	0	0	0	0	4
17003	0	0	0	0	0	1	0	2	1	0	1	0	5
17009	0	0	0	0	1	1	0	1	0	1	0	0	4
17010	0	0	0	0	0	0	1	0	0	0	0	0	1
17011	0	0	0	4	1	5	4	5	11	4	3	0	37
17013	0	0	0	9	8	3	12	7	10	0	10	0	60
17015	0	0	0	0	1	2	2	2	3	0	1	0	11
17018	0	0	0	1	0	0	0	0	0	0	0	0	1
17022	0	0	0	3	2	4	4	4	3	3	0	0	23
17025	0	0	0	3	2	0	2	8	10	1	1	0	27
17026	0	0	0	0	0	0	1	0	0	0	0	0	1

17033	0	0	0	3	0	0	2	0	4	0	0	0	9
17034	0	0	0	1	1	2	0	2	2	3	1	0	12
17036	0	0	0	5	2	2	7	1	4	3	7	0	31
17042	0	0	0	9	8	6	7	4	7	4	3	0	48
17043	0	0	0	2	4	2	2	0	4	1	1	0	16
17044	0	0	0	6	4	8	2	7	5	4	0	0	38
17046	0	0	0	10	6	7	10	8	17	5	2	0	65
17050	0	0	0	0	1	0	3	3	5	1	0	0	14
17055	0	0	0	2	2	2	5	3	7	0	1	0	22
17057	0	0	0	0	4	2	7	0	3	5	3	0	24
17060	0	0	0	0	0	0	0	0	1	0	0	0	1
17065	0	0	0	0	0	1	0	0	0	0	0	0	1
17066	0	0	0	1	0	1	0	1	0	0	0	0	3
17067	0	0	0	1	1	1	4	0	2	0	2	0	11
17070	0	0	0	3	1	0	5	2	11	0	1	0	23
17073	0	0	0	0	0	1	1	0	0	0	0	0	2
17078	0	0	0	3	0	0	3	0	3	1	0	0	10
17087	0	0	0	0	1	0	0	0	0	0	0	0	1
17099	0	0	0	1	0	1	0	0	0	0	0	0	2
17101	0	0	0	0	0	1	0	0	0	1	0	0	2
17102	0	0	0	0	9	4	3	9	8	2	1	0	36
17103	0	0	0	24	17	16	21	11	25	9	5	0	130
17104	0	0	0	30	14	20	18	22	31	14	16	0	169
17109	0	0	0	10	4	4	8	5	13	2	4	0	50
17110	0	0	0	19	16	10	20	24	16	11	11	0	128
17111	0	0	0	7	10	4	8	10	12	3	2	0	56
17112	0	0	0	2	2	2	0	13	6	0	0	0	26
17113	0	0	0	7	22	11	2	4	21	11	11	0	89
17202	0	0	0	0	1	0	0	1	0	0	0	0	2
17250	0	0	0	0	0	1	0	0	0	0	0	0	1
17257	0	0	0	4	5	5	1	9	2	4	2	0	32
17268	0	0	0	10	6	3	4	5	1	2	2	0	33
17512	0	0	0	8	13	2	13	7	10	5	1	0	59
17517	0	0	0	0	0	2	1	1	0	0	0	0	4
17520	0	0	0	0	1	3	0	0	1	2	0	0	7
17522	0	0	0	1	0	1	0	0	1	0	0	0	4

17538	0	0	0	0	1	0	2	0	0	0	1	0	4
17540	0	0	0	1	0	2	4	2	1	0	2	0	12
17543	0	0	0	3	3	3	2	3	0	2	2	0	18
17545	0	0	0	2	2	2	1	0	4	1	1	0	13
17547	0	0	0	2	2	0	6	2	3	2	0	0	17
17550	0	0	0	0	0	0	0	1	2	0	0	0	3
17551	0	0	0	1	3	2	1	0	2	4	0	0	13
17552	0	0	0	2	2	0	1	3	3	4	0	0	15
17554	0	0	0	3	4	2	0	1	3	8	0	0	22
17557	0	0	0	0	4	1	1	3	0	2	1	0	12
17569	0	0	0	0	0	1	0	0	1	1	1	0	4
17578	0	0	0	0	0	0	1	0	0	0	0	0	1
17584	0	0	0	0	0	0	1	0	0	1	0	0	2
17601	0	0	0	3	10	6	4	11	14	3	4	0	55
17602	0	0	0	15	41	18	37	24	30	13	14	0	193
17603	0	0	0	24	50	18	37	34	45	29	19	0	256
17701	0	0	0	25	33	22	55	30	14	32	13	0	224
17702	0	0	0	4	3	4	8	4	2	2	3	0	30
17721	0	0	0	0	1	0	0	0	0	0	0	0	1
17724	0	0	0	2	3	2	5	4	0	1	0	0	17
17728	0	0	0	0	0	0	0	0	1	0	0	0	1
17735	0	0	0	0	1	0	0	0	0	0	0	0	1
17737	0	0	0	0	1	0	1	0	1	0	0	0	3
17740	0	0	0	2	2	3	4	4	1	2	0	0	18
17745	0	0	0	1	1	5	5	4	1	1	0	0	18
17748	0	0	0	0	0	1	2	0	0	0	0	0	3
17752	0	0	0	3	2	2	3	1	2	1	2	0	17
17754	0	0	0	1	3	9	4	2	3	2	3	0	27
17756	0	0	0	1	1	1	2	4	2	0	2	0	13
17760	0	0	0	0	0	0	0	0	0	1	1	0	2
17762	0	0	0	0	2	0	0	1	0	0	0	0	3
17764	0	0	0	0	2	3	1	1	3	2	1	0	14
17772	0	0	0	1	1	0	1	0	0	0	0	0	3
17777	0	0	0	3	0	3	1	1	0	0	0	0	8
17801	0	0	0	13	18	16	15	7	6	11	5	0	91
17815	0	0	0	6	5	3	9	7	3	6	2	0	41

17821	0	0	0	0	3	2	6	1	0	0	1	0	13
17837	0	0	0	0	0	0	0	1	1	0	0	0	2
17847	0	0	0	12	4	4	6	6	0	7	1	0	41
17850	0	0	0	1	0	0	0	0	0	1	0	0	2
17851	0	0	0	5	4	6	3	3	1	6	2	0	30
17857	0	0	0	2	6	2	2	1	2	2	1	0	18
17866	0	0	0	0	1	3	5	4	0	1	0	0	14
17870	0	0	0	1	0	1	6	1	0	2	1	0	12
17872	0	0	0	3	1	5	7	4	0	5	3	0	29
17876	0	0	0	0	1	1	0	0	2	0	0	0	4
17886	0	0	0	0	1	0	0	0	0	0	0	0	1
17901	0	0	0	12	6	12	9	9	0	8	4	0	61
17921	0	0	0	1	1	1	0	0	0	1	1	0	5
17931	0	0	0	0	0	0	0	1	0	0	0	0	1
18011	0	0	0	1	0	0	0	1	0	0	0	0	2
18013	0	0	0	1	3	5	0	4	4	2	0	0	19
18014	0	0	0	1	1	0	0	0	0	1	0	0	3
18015	0	0	0	14	9	15	29	23	31	21	20	0	164
18017	0	0	0	2	2	12	16	6	8	12	9	0	67
18018	0	0	0	9	7	12	36	14	16	9	12	0	116
18020	0	0	0	0	0	4	1	1	1	2	3	0	12
18031	0	0	0	1	1	0	2	6	3	2	0	0	15
18032	0	0	0	1	7	2	5	7	6	4	1	0	33
18034	0	0	0	0	0	0	2	2	0	2	0	0	6
18036	0	0	0	0	0	0	0	2	0	0	0	0	2
18037	0	0	0	1	1	2	0	0	1	0	0	0	5
18040	0	0	0	0	2	0	5	3	4	2	3	0	19
18042	0	0	0	9	6	17	36	23	23	16	25	0	155
18045	0	0	0	4	0	1	6	7	3	4	2	0	27
18049	0	0	0	1	2	2	3	3	0	4	2	0	17
18052	0	0	0	8	4	7	3	6	0	11	0	0	40
18055	0	0	0	1	0	0	3	5	1	0	2	0	12
18062	0	0	0	3	2	1	7	3	4	1	0	0	21
18064	0	0	0	1	0	0	1	3	1	2	0	0	8
18067	0	0	0	5	2	3	8	11	2	2	1	0	34
18068	0	0	0	0	0	0	1	0	0	0	0	0	1

18069	0	0	0	0	0	0	0	2	0	0	0	0	2
18071	0	0	0	0	1	1	2	0	1	2	0	0	7
18072	0	0	0	2	3	1	2	2	2	1	1	0	14
18080	0	0	0	0	2	0	1	0	0	0	0	0	3
18101	0	0	0	3	1	2	1	2	6	0	1	0	16
18102	0	0	0	47	22	29	63	52	42	47	35	0	339
18103	0	0	0	10	7	6	18	17	20	8	13	0	100
18104	0	0	0	6	8	6	13	7	10	10	4	0	64
18106	0	0	0	0	0	0	0	1	0	0	0	0	1
18109	0	0	0	2	2	5	13	7	19	14	7	0	69
18201	0	0	0	59	32	21	78	66	28	29	18	0	332
18202	0	0	0	6	8	4	14	18	13	5	5	0	73
18219	0	0	0	0	1	0	0	1	1	0	0	0	3
18221	0	0	0	0	0	0	0	1	0	0	0	0	1
18222	0	0	0	1	0	0	0	1	0	0	0	0	2
18224	0	0	0	1	1	0	0	0	0	0	0	0	2
18229	0	0	0	4	3	1	1	2	0	1	0	0	12
18235	0	0	0	1	2	1	3	5	1	2	0	0	15
18237	0	0	0	0	0	0	0	1	0	0	1	0	2
18301	0	0	0	10	7	11	8	7	8	5	4	0	60
18327	0	0	0	0	0	0	0	1	0	0	0	0	1
18337	0	0	0	1	0	1	0	1	0	1	0	0	4
18360	0	0	0	9	3	5	4	7	1	4	2	0	36
18403	0	0	0	3	1	6	5	4	2	5	5	0	31
18407	0	0	0	6	10	12	23	15	12	2	13	0	93
18410	0	0	0	0	0	1	1	0	0	0	0	0	2
18411	0	0	0	7	4	4	3	2	6	6	2	0	34
18414	0	0	0	1	2	1	0	0	2	0	0	0	6
18419	0	0	0	0	1	2	0	0	0	0	1	0	5
18421	0	0	0	0	0	1	3	1	0	1	1	0	7
18428	0	0	0	1	2	0	0	0	0	0	0	0	3
18431	0	0	0	4	4	5	3	2	3	1	0	0	22
18433	0	0	0	1	1	5	3	3	4	1	4	0	22
18434	0	0	0	0	6	3	1	5	2	2	3	0	22
18447	0	0	0	9	3	12	12	10	2	2	6	0	57
18452	0	0	0	1	1	4	6	3	4	1	1	0	21

18471	0	0	0	0	2	0	1	0	1	0	1	0	5
18504	0	0	0	16	48	21	45	48	6	14	15	0	218
18505	0	0	0	5	27	26	23	23	10	11	5	0	131
18507	0	0	0	3	3	2	1	5	2	2	0	0	19
18508	0	0	0	14	19	6	25	17	4	5	7	0	97
18509	0	0	0	11	10	8	16	11	10	10	8	0	84
18510	0	0	0	8	13	12	12	9	6	3	4	0	68
18512	0	0	0	8	2	6	16	7	6	3	5	0	54
18517	0	0	0	4	2	4	5	4	5	1	0	0	25
18518	0	0	0	5	9	1	3	8	4	4	1	0	35
18519	0	0	0	3	1	5	4	5	3	3	1	0	25
18603	0	0	0	12	9	7	17	5	4	10	3	0	67
18610	0	0	0	0	0	0	1	0	0	1	0	0	2
18612	0	0	0	4	1	1	2	0	3	1	0	0	12
18618	0	0	0	0	0	0	1	1	0	0	0	0	2
18627	0	0	0	1	0	0	0	1	0	0	0	0	2
18634	0	0	0	10	12	8	11	13	6	3	2	0	66
18635	0	0	0	0	0	1	2	1	1	0	0	0	5
18640	0	0	0	18	8	8	15	10	2	8	4	0	73
18641	0	0	0	5	3	2	1	5	0	1	1	0	18
18642	0	0	0	4	0	2	6	7	0	0	2	0	22
18643	0	0	0	9	5	7	7	11	3	8	1	0	51
18644	0	0	0	2	3	3	2	1	8	0	2	0	21
18651	0	0	0	15	7	8	8	11	6	1	2	0	58
18653	0	0	0	1	0	0	0	1	0	0	0	0	2
18661	0	0	0	0	0	0	1	2	0	0	0	0	3
18701	0	0	0	2	1	0	0	1	2	0	2	0	8
18702	0	0	0	41	63	36	64	64	56	21	34	0	380
18704	0	0	0	27	15	11	17	31	13	12	8	0	135
18705	0	0	0	17	18	13	15	24	7	7	9	0	111
18706	0	0	0	10	15	10	16	18	9	5	4	0	87
18707	0	0	0	1	3	2	2	3	4	0	3	0	18
18708	0	0	0	4	2	1	3	1	1	0	0	0	12
18709	0	0	0	0	1	1	2	1	0	1	2	0	8
18814	0	0	0	0	0	0	1	0	0	0	0	0	1
18831	0	0	0	0	0	1	0	0	0	0	1	0	2

18944	0	0	0	1	0	0	3	2	4	3	2	0	15
18951	0	0	0	1	0	1	2	3	2	1	0	0	10
18960	0	0	0	0	0	0	0	1	0	0	2	0	3
19363	0	0	0	3	5	3	2	5	1	4	1	0	25
19464	0	0	0	0	0	1	0	0	0	0	0	0	1
19508	0	0	0	0	2	3	2	1	4	1	1	0	14
19510	0	0	0	0	1	1	1	0	2	1	0	0	6
19512	0	0	0	0	0	1	1	0	0	0	2	0	4
19518	0	0	0	1	3	3	3	0	3	1	3	0	17
19522	0	0	0	1	1	4	3	1	0	2	0	0	12
19525	0	0	0	1	0	2	1	1	1	0	1	0	7
19526	0	0	0	0	1	2	3	1	1	0	0	0	8
19530	0	0	0	0	1	1	0	0	1	0	1	0	4
19533	0	0	0	1	0	0	0	0	0	0	0	0	1
19539	0	0	0	0	0	0	1	0	0	0	0	0	1
19540	0	0	0	1	0	1	2	1	0	0	0	0	5
19543	0	0	0	0	0	0	0	0	1	1	0	0	2
19551	0	0	0	1	1	0	0	0	2	0	1	0	6
19555	0	0	0	0	0	0	1	1	0	0	0	0	2
19560	0	0	0	1	3	4	5	2	2	1	0	0	18
19562	0	0	0	0	1	0	0	0	0	0	0	0	1
19565	0	0	0	0	0	1	2	2	0	2	0	0	7
19567	0	0	0	2	1	0	0	1	3	0	1	0	8
19601	0	0	0	18	16	31	58	28	33	17	13	0	216
19602	0	0	0	19	8	10	34	32	23	15	10	0	151
19604	0	0	0	17	20	32	33	40	28	11	16	0	197
19605	0	0	0	8	3	11	11	9	16	3	6	0	67
19606	0	0	0	8	8	6	33	14	15	7	8	0	100
19607	0	0	0	2	5	1	6	13	8	8	2	0	45
19608	0	0	0	1	3	0	7	5	5	2	4	0	27
19609	0	0	0	2	3	8	3	2	7	3	2	0	30
19610	0	0	0	2	2	5	1	4	2	1	4	0	21
19611	0	0	0	2	3	5	7	2	0	5	2	0	26
Grand Total	**0**	**0**	**0**	**1018**	**1037**	**943**	**1507**	**1320**	**1085**	**778**	**609**	**0**	**8349**

UGI UTILITIES, INC. – GAS DIVISION
NONPAYMENT DISCONNECTIONS FOR CONFIRMED LOW-INCOME RESIDENTIAL CUSTOMERS (without CAP)
FOR CALENDAR YEAR 2025

Zip Code	January	February	March	April	May	June	July	August	September	October	November	December	Zip Code Total
15522	0	0	0	0	1	0	3	3	1	1	0	0	9
16213	0	0	0	1	0	0	0	0	0	1	0	0	2
16214	0	0	0	0	0	0	2	0	2	0	0	0	4
16232	0	0	0	1	1	1	0	0	0	1	0	0	4
16233	0	0	0	0	0	1	0	0	0	0	0	0	1
16235	0	0	0	0	0	0	1	0	1	1	0	0	3
16239	0	0	0	0	2	0	0	0	0	0	1	0	3
16254	0	0	0	1	0	0	2	0	0	0	0	0	3
16255	0	0	0	1	0	0	0	0	0	0	0	0	1
16260	0	0	0	1	0	0	0	0	0	0	0	0	1
16301	0	0	0	1	1	0	0	0	1	1	1	0	5
16319	0	0	0	0	0	0	0	0	1	0	0	0	1
16326	0	0	0	0	0	0	0	0	1	1	0	0	2
16353	0	0	0	2	2	3	0	4	2	3	0	0	16
16364	0	0	0	0	0	0	2	0	0	0	0	0	2
16373	0	0	0	1	0	1	1	2	0	0	0	0	5
16652	0	0	0	5	2	7	5	3	2	1	0	0	26
16662	0	0	0	0	0	0	2	0	0	0	0	0	2
16673	0	0	0	0	1	1	0	1	0	1	0	0	4
16720	0	0	0	0	0	0	1	0	0	0	0	0	1
16724	0	0	0	0	0	0	0	0	2	0	0	0	2
16731	0	0	0	1	1	8	2	2	2	5	2	0	23
16743	0	0	0	6	7	4	3	3	3	1	4	0	31
16746	0	0	0	0	1	0	2	1	0	1	0	0	5

16748	0	0	0	3	3	6	3	6	1	2	0	0	24
16749	0	0	0	0	0	1	0	2	1	0	0	0	4
16830	0	0	0	6	4	8	2	1	3	3	1	0	28
16843	0	0	0	0	1	0	0	0	0	0	0	0	1
16866	0	0	0	1	1	0	2	2	2	0	0	0	8
16901	0	0	0	4	1	6	8	6	3	2	1	0	31
16911	0	0	0	0	1	0	0	0	0	1	0	0	2
16912	0	0	0	2	1	0	1	2	2	2	0	0	10
16914	0	0	0	0	2	0	1	1	0	0	0	0	4
16915	0	0	0	1	1	3	1	1	0	6	1	0	14
16917	0	0	0	1	4	0	0	2	2	2	0	0	11
16920	0	0	0	0	1	2	0	1	2	1	1	0	8
16921	0	0	0	0	1	0	0	0	0	0	0	0	1
16922	0	0	0	0	3	2	1	0	0	1	0	0	7
16923	0	0	0	1	0	0	1	2	0	0	0	0	4
16925	0	0	0	1	2	3	1	2	2	1	0	0	12
16927	0	0	0	0	0	2	0	0	1	0	0	0	3
16928	0	0	0	0	1	1	3	0	1	0	1	0	7
16929	0	0	0	0	2	4	1	2	1	1	1	0	12
16930	0	0	0	0	2	0	0	0	1	0	0	0	3
16932	0	0	0	1	0	0	1	0	1	0	0	0	3
16933	0	0	0	2	3	4	3	6	1	3	0	0	22
16935	0	0	0	1	0	0	0	0	0	0	0	0	1
16936	0	0	0	1	0	2	1	0	2	1	1	0	8
16939	0	0	0	0	0	3	1	0	0	2	0	0	6
16940	0	0	0	1	0	0	1	0	0	1	0	0	3
16942	0	0	0	0	0	1	0	0	0	1	0	0	2
16946	0	0	0	2	1	2	1	0	3	2	1	0	12
16947	0	0	0	4	4	1	5	3	3	5	1	0	26
16948	0	0	0	0	0	2	1	1	0	0	0	0	4
16950	0	0	0	3	3	0	2	4	0	1	0	0	13
17003	0	0	0	2	0	0	4	1	2	0	1	0	10
17009	0	0	0	1	2	0	0	1	0	1	0	0	5

17011	0	0	0	8	2	2	4	13	14	13	6	0	62
17013	0	0	0	6	5	6	15	7	14	13	9	0	76
17015	0	0	0	2	0	0	2	4	0	3	1	0	12
17018	0	0	0	0	0	0	1	0	1	1	0	0	3
17022	0	0	0	2	3	8	4	3	3	5	1	0	29
17025	0	0	0	2	2	3	4	6	11	6	4	0	38
17026	0	0	0	0	0	0	1	0	0	0	1	0	2
17033	0	0	0	2	1	1	1	4	2	4	4	0	19
17034	0	0	0	1	0	0	1	1	2	0	2	0	7
17036	0	0	0	3	0	2	3	6	2	6	2	0	24
17042	0	0	0	8	11	5	16	12	12	18	5	0	88
17043	0	0	0	1	1	1	3	1	5	1	4	0	17
17044	0	0	0	8	7	12	4	8	5	3	1	0	48
17046	0	0	0	4	9	16	15	12	25	24	13	0	118
17050	0	0	0	2	2	5	7	2	7	2	5	0	32
17052	0	0	0	0	0	0	1	0	0	0	0	0	1
17055	0	0	0	3	0	9	11	5	10	8	7	0	53
17057	0	0	0	0	5	5	1	6	9	10	6	0	42
17065	0	0	0	1	0	0	0	0	0	0	0	0	1
17066	0	0	0	1	0	0	0	0	1	0	0	0	2
17067	0	0	0	1	1	1	1	0	3	4	3	0	14
17070	0	0	0	2	2	3	8	6	10	5	2	0	39
17073	0	0	0	1	1	0	0	0	0	1	1	0	4
17078	0	0	0	1	1	1	2	3	2	2	1	0	13
17099	0	0	0	0	0	0	1	0	1	0	0	0	2
17101	0	0	0	0	0	0	1	0	1	1	1	0	4
17102	0	0	0	9	1	8	6	8	8	12	6	0	59
17103	0	0	0	16	23	19	25	20	24	30	23	0	180
17104	0	0	0	13	19	28	44	13	61	43	33	0	258
17109	0	0	0	8	3	4	12	13	10	12	11	0	74
17110	0	0	0	27	21	22	31	40	28	26	16	0	212
17111	0	0	0	8	5	0	25	9	14	17	13	0	91
17112	0	0	0	3	1	6	5	6	4	8	2	0	35

17113	0	0	0	5	15	12	16	5	20	25	21	0	120
17202	0	0	0	0	0	1	0	0	0	0	0	0	1
17257	0	0	0	5	2	7	6	6	6	5	0	0	37
17268	0	0	0	7	4	6	8	4	5	0	0	0	34
17319	0	0	0	0	0	0	1	0	0	0	0	0	1
17504	0	0	0	0	0	0	0	1	0	0	0	0	1
17512	0	0	0	8	2	10	15	11	12	10	2	0	70
17517	0	0	0	0	1	0	0	0	1	0	0	0	2
17520	0	0	0	0	2	1	0	0	0	2	0	0	5
17538	0	0	0	1	0	0	0	1	1	1	0	0	4
17540	0	0	0	2	1	1	4	3	1	4	1	0	17
17543	0	0	0	3	0	3	6	5	4	6	4	0	31
17545	0	0	0	1	3	3	2	3	3	1	1	0	17
17547	0	0	0	1	0	3	3	3	3	2	2	0	17
17550	0	0	0	0	1	0	1	0	1	0	0	0	3
17551	0	0	0	2	1	6	2	4	0	5	0	0	21
17552	0	0	0	3	0	2	5	0	2	4	1	0	17
17554	0	0	0	2	0	1	3	2	5	1	2	0	16
17557	0	0	0	0	3	2	0	1	5	2	1	0	14
17569	0	0	0	0	0	0	1	0	1	1	0	0	3
17578	0	0	0	0	0	1	0	0	0	0	1	0	2
17601	0	0	0	0	6	10	10	10	6	5	4	0	51
17602	0	0	0	18	14	43	38	38	35	25	22	0	234
17603	0	0	0	14	22	48	46	58	55	22	10	0	276
17701	0	0	0	39	29	66	40	49	59	31	26	0	340
17702	0	0	0	6	14	5	2	7	4	2	3	0	43
17721	0	0	0	0	1	1	0	0	0	1	0	0	3
17724	0	0	0	4	0	3	3	3	2	1	2	0	18
17728	0	0	0	0	0	0	1	1	0	0	1	0	3
17735	0	0	0	0	1	0	0	0	0	0	0	0	1
17737	0	0	0	2	0	0	1	1	0	0	0	0	4
17740	0	0	0	3	2	2	2	6	6	0	0	0	21
17745	0	0	0	1	1	12	3	5	4	1	0	0	27

17748	0	0	0	0	0	1	0	0	0	0	0	0	1
17751	0	0	0	0	0	0	0	1	0	0	0	0	1
17752	0	0	0	0	3	0	2	2	1	0	1	0	10
17754	0	0	0	1	4	6	1	5	8	2	2	0	29
17756	0	0	0	1	0	3	2	2	2	0	0	0	11
17762	0	0	0	0	0	1	0	0	0	0	0	0	1
17764	0	0	0	5	1	5	4	2	0	1	0	0	18
17772	0	0	0	1	0	0	1	0	0	0	0	0	2
17777	0	0	0	0	3	1	2	2	0	1	1	0	10
17801	0	0	0	17	19	18	10	20	11	5	6	0	108
17815	0	0	0	9	7	5	13	4	9	3	1	0	51
17821	0	0	0	0	1	2	1	2	5	0	1	0	12
17833	0	0	0	0	0	1	0	0	0	0	0	0	1
17834	0	0	0	0	0	1	0	0	0	0	0	0	1
17837	0	0	0	0	1	1	1	0	1	0	0	0	4
17847	0	0	0	10	3	7	6	5	12	1	2	0	46
17850	0	0	0	1	0	0	1	1	1	0	0	0	4
17851	0	0	0	4	5	3	7	6	9	3	2	0	39
17857	0	0	0	4	3	7	3	1	3	4	1	0	27
17866	0	0	0	1	2	6	6	1	3	3	2	0	24
17870	0	0	0	1	2	2	3	2	1	0	1	0	12
17872	0	0	0	5	4	4	8	7	4	3	1	0	36
17876	0	0	0	2	1	1	1	0	1	0	0	0	6
17886	0	0	0	1	0	1	0	1	0	0	1	0	4
17887	0	0	0	1	0	0	0	0	1	2	0	0	4
17901	0	0	0	11	11	13	6	9	12	10	5	0	77
17921	0	0	0	1	1	0	1	2	2	0	2	0	10
17922	0	0	0	1	1	0	0	0	0	1	0	0	3
17931	0	0	0	0	1	0	0	0	0	0	0	0	1
18011	0	0	0	1	0	1	3	0	2	0	3	0	10
18013	0	0	0	6	2	6	5	3	3	1	3	0	29
18014	0	0	0	0	1	1	1	0	2	0	0	0	5
18015	0	0	0	12	25	21	30	28	31	24	15	0	187

18017	0	0	0	1	0	7	15	6	24	4	10	0	67
18018	0	0	0	8	15	27	15	29	18	12	13	0	139
18020	0	0	0	3	1	2	6	3	6	1	3	0	25
18031	0	0	0	6	2	2	8	1	8	1	3	0	31
18032	0	0	0	8	3	4	5	10	7	1	0	0	38
18034	0	0	0	0	0	1	1	0	1	1	1	0	5
18036	0	0	0	0	0	0	0	2	1	0	0	0	3
18037	0	0	0	2	0	3	2	0	3	1	1	0	12
18040	0	0	0	0	1	4	6	2	1	0	2	0	16
18042	0	0	0	16	23	20	52	20	56	10	24	0	221
18045	0	0	0	3	0	4	6	2	6	3	3	0	27
18049	0	0	0	1	1	3	7	2	2	2	4	0	22
18052	0	0	0	6	2	2	10	6	16	5	5	0	53
18055	0	0	0	0	0	1	0	5	1	1	1	0	10
18062	0	0	0	5	1	8	6	2	5	2	0	0	29
18064	0	0	0	1	0	1	1	5	1	0	2	0	11
18067	0	0	0	6	5	3	8	4	6	5	1	0	38
18069	0	0	0	0	1	0	1	0	0	0	0	0	2
18071	0	0	0	2	0	0	0	0	3	0	0	0	5
18072	0	0	0	1	2	2	0	4	2	0	3	0	14
18080	0	0	0	1	2	1	1	2	0	1	0	0	8
18087	0	0	0	0	0	0	1	0	0	0	0	0	1
18091	0	0	0	0	1	1	0	0	0	0	0	0	2
18101	0	0	0	4	3	0	4	4	6	1	2	0	26
18102	0	0	0	33	64	39	88	73	95	66	44	0	503
18103	0	0	0	5	15	17	12	14	25	11	26	0	125
18104	0	0	0	7	5	4	14	12	18	4	7	0	71
18106	0	0	0	0	0	0	1	0	1	0	1	0	3
18109	0	0	0	12	8	19	16	23	16	14	10	0	118
18201	0	0	0	59	61	46	120	47	70	35	12	0	454
18202	0	0	0	14	8	10	28	7	20	7	7	0	102
18219	0	0	0	0	0	0	0	0	0	1	0	0	1
18221	0	0	0	0	0	0	0	1	0	0	0	0	1

18222	0	0	0	0	1	1	1	1	0	0	0	0	4
18224	0	0	0	1	0	0	0	0	0	1	0	0	2
18225	0	0	0	0	0	0	2	0	0	0	2	0	4
18229	0	0	0	2	3	4	2	1	1	0	1	0	14
18235	0	0	0	5	3	6	4	3	1	1	1	0	24
18237	0	0	0	0	0	0	1	0	0	1	0	0	2
18301	0	0	0	7	7	14	9	20	7	5	4	0	73
18337	0	0	0	0	0	1	0	0	0	0	0	0	1
18360	0	0	0	4	4	11	6	4	5	7	2	0	44
18403	0	0	0	1	6	1	5	6	4	3	3	0	29
18407	0	0	0	14	10	17	15	22	10	16	5	0	110
18410	0	0	0	0	0	0	0	1	0	0	0	0	1
18411	0	0	0	2	3	1	6	4	4	1	5	0	26
18414	0	0	0	0	1	0	0	1	0	1	0	0	3
18419	0	0	0	1	0	0	0	4	1	0	0	0	6
18421	0	0	0	1	0	0	2	2	2	1	0	0	8
18428	0	0	0	1	1	0	0	0	0	0	0	0	2
18431	0	0	0	2	5	5	2	5	5	2	2	0	28
18433	0	0	0	6	1	3	7	9	3	1	7	0	37
18434	0	0	0	2	4	3	2	4	3	3	1	0	22
18447	0	0	0	2	5	5	12	13	8	2	5	0	52
18452	0	0	0	4	2	1	6	5	2	2	3	0	25
18471	0	0	0	0	1	0	1	0	0	2	0	0	4
18504	0	0	0	36	35	41	60	57	38	27	5	0	302
18505	0	0	0	21	23	32	37	43	29	11	4	0	203
18507	0	0	0	2	2	0	5	1	2	4	0	0	16
18508	0	0	0	30	5	9	30	22	25	14	5	0	142
18509	0	0	0	23	7	17	21	15	15	8	7	0	114
18510	0	0	0	14	5	11	21	14	17	5	7	0	95
18512	0	0	0	6	9	9	18	10	8	8	4	0	72
18517	0	0	0	3	1	1	2	1	2	5	3	0	18
18518	0	0	0	10	3	5	6	6	1	10	4	0	45
18519	0	0	0	1	7	1	5	6	7	0	7	0	34

18603	0	0	0	18	13	18	9	23	16	13	3	0	113
18612	0	0	0	2	1	2	3	1	2	2	1	0	14
18618	0	0	0	0	0	1	0	0	0	0	0	0	1
18634	0	0	0	9	7	2	9	12	12	11	9	0	71
18635	0	0	0	0	0	1	2	2	1	2	0	0	8
18640	0	0	0	15	14	15	8	19	17	15	11	0	114
18641	0	0	0	3	3	0	3	4	1	3	2	0	19
18642	0	0	0	4	0	2	6	1	3	4	1	0	21
18643	0	0	0	8	3	8	6	5	10	12	0	0	52
18644	0	0	0	3	2	2	3	0	1	1	6	0	18
18651	0	0	0	22	6	11	11	4	4	15	7	0	80
18653	0	0	0	1	0	1	0	0	0	0	0	0	2
18661	0	0	0	0	1	0	0	2	1	0	0	0	4
18701	0	0	0	0	1	0	1	2	3	1	0	0	8
18702	0	0	0	32	84	51	51	39	71	79	48	0	456
18704	0	0	0	20	24	15	19	12	13	41	7	0	151
18705	0	0	0	15	18	12	17	11	24	21	16	0	134
18706	0	0	0	24	16	9	15	9	16	16	5	0	110
18707	0	0	0	2	2	1	7	0	2	3	2	0	19
18708	0	0	0	2	0	2	0	0	1	1	2	0	8
18709	0	0	0	0	2	3	2	0	3	2	1	0	13
18831	0	0	0	0	1	0	0	0	0	0	0	0	1
18850	0	0	0	0	0	0	0	0	0	0	1	0	1
18944	0	0	0	2	0	0	3	2	0	0	3	0	10
18951	0	0	0	3	0	2	5	2	6	0	2	0	20
18955	0	0	0	0	0	0	0	0	1	0	0	0	1
18960	0	0	0	1	0	1	2	0	3	0	0	0	7
19362	0	0	0	0	0	0	1	0	0	0	0	0	1
19363	0	0	0	3	2	4	4	5	2	3	3	0	29
19464	0	0	0	0	0	0	1	0	0	0	0	0	1
19508	0	0	0	2	0	5	3	1	4	4	1	0	21
19510	0	0	0	2	0	1	0	2	2	2	1	0	10
19512	0	0	0	0	0	3	0	0	0	0	1	0	4

19518	0	0	0	2	0	4	4	2	3	0	1	0	16
19522	0	0	0	3	0	4	0	2	3	1	1	0	14
19525	0	0	0	1	2	0	3	0	1	0	0	0	7
19526	0	0	0	3	1	4	3	3	1	3	0	0	18
19530	0	0	0	0	2	3	0	0	0	0	0	0	5
19533	0	0	0	0	0	1	1	0	2	0	0	0	4
19540	0	0	0	3	3	2	1	3	0	0	0	0	12
19543	0	0	0	0	0	1	0	0	0	0	0	0	1
19551	0	0	0	0	0	1	0	0	2	0	0	0	3
19555	0	0	0	2	0	0	2	3	0	0	0	0	7
19560	0	0	0	2	3	3	2	5	6	1	1	0	23
19565	0	0	0	0	3	1	3	2	0	0	0	0	9
19567	0	0	0	0	1	0	1	2	0	3	0	0	7
19601	0	0	0	23	30	45	54	35	59	21	28	0	296
19602	0	0	0	15	11	42	20	32	34	30	13	0	200
19604	0	0	0	25	30	45	49	26	43	19	16	0	255
19605	0	0	0	4	5	7	14	7	9	4	5	0	55
19606	0	0	0	16	4	17	24	16	23	16	3	0	120
19607	0	0	0	8	9	9	8	11	13	6	1	0	65
19608	0	0	0	3	1	4	7	8	7	2	2	0	34
19609	0	0	0	0	6	9	11	2	9	4	2	0	44
19610	0	0	0	1	0	6	4	5	6	0	3	0	25
19611	0	0	0	4	6	4	7	4	8	2	1	0	36
Grand Total	**0**	**0**	**0**	**1138**	**1110**	**1427**	**1794**	**1498**	**1772**	**1249**	**837**	**0**	**10885**

OCA-7-2

Request:

Please identify the revenue of the monthly Weather Normalization Adjustment ("WNA") for each Delivery Region since November 2022 through the most recent month available for customer classes R, RT, N, and NT. Provide all calculations in Excel format with all formulas intact.

Response:

Please see Attachment OCA-7-2 provided in Excel for the monthly recorded Weather Normalized Adjustment revenue billed for each of the four Delivery Regions. The Delivery Region is referenced as Temperature Area on the attachment and includes GC (Central), GN (North), GS (South), and GW (West). The included data is the output of a billing system report and presented based on the revenue month in which the related billing activity invoices posted and were recorded. As a result, there will be data in months outside of the WNA period of October through May as related to billing adjustments.

Prepared by or under the supervision of: Tracy A. Hazenstab

WNA Summary Report

Revenue Month NOV 2022 - JAN 2026
Rate Category Rate NT

	Revenue Month	GC	GN	GS	GW
WNA Revenue	NOV 2022	$ 40,612.03	$ 18,886.34	$ 125,276.48	$ 313.59
WNA Revenue	DEC 2022	$ 29,505.99	$ 17,674.91	$ 59,006.76	$ 887.95
WNA Revenue	JAN 2023	$ 181,257.77	$ 82,212.35	$ 406,149.98	$ 2,561.77
WNA Revenue	FEB 2023	$ 215,393.40	$ 97,032.42	$ 984,658.82	$ 6,482.49
WNA Revenue	MAR 2023	$ 170,827.34	$ 91,314.70	$ 813,299.11	$ 8,289.84
WNA Revenue	APR 2023	$ 84,338.17	$ 43,140.07	$ 386,796.69	$ 1,251.46
WNA Revenue	MAY 2023	$ 10,394.96	$ 15,293.01	$ 51,961.89	$ (390.40)
WNA Revenue	JUN 2023	$ (1,168.31)	$ (114.20)	$ 635.42	$ (5.73)
WNA Revenue	JUL 2023	$ (30.74)	$ (4.20)	$ (625.02)	
WNA Revenue	AUG 2023		$ (15.91)	$ (722.37)	
WNA Revenue	SEP 2023		$ 3.16	$ (235.70)	
WNA Revenue	OCT 2023	$ 5,686.01	$ 14,052.29	$ 25,559.22	$ 114.64
WNA Revenue	NOV 2023	$ 13,008.73	$ 35,906.57	$ 100,266.80	$ 1,647.69
WNA Revenue	DEC 2023	$ 54,208.40	$ 49,489.39	$ 131,715.22	$ 6,366.21
WNA Revenue	JAN 2024	$ 203,389.05	$ 112,203.69	$ 727,090.57	$ 13,642.94
WNA Revenue	FEB 2024	$ 199,125.52	$ 127,366.60	$ 777,027.22	$ 10,835.68
WNA Revenue	MAR 2024	$ 278,577.69	$ 158,185.53	$ 1,010,492.11	$ 12,358.15
WNA Revenue	APR 2024	$ 134,712.47	$ 83,576.74	$ 447,181.24	$ 4,412.02
WNA Revenue	MAY 2024	$ 91,107.35	$ 56,662.18	$ 222,353.57	$ 3,330.42
WNA Revenue	JUN 2024	$ 8,806.92	$ 11,939.76	$ 27,319.30	$ (41.06)
WNA Revenue	JUL 2024	$ 1,380.11	$ 236.97	$ (9,015.43)	$ 0.38
WNA Revenue	AUG 2024	$ 138.92	$ 5.37	$ (787.65)	
WNA Revenue	SEP 2024	$ (34.15)		$ (646.67)	
WNA Revenue	OCT 2024	$ 21,168.82	$ 18,416.12	$ 96,940.12	$ 1,973.37
WNA Revenue	NOV 2024	$ 87,117.72	$ 66,949.21	$ 342,682.57	$ 3,029.97
WNA Revenue	DEC 2024	$ (5,499.34)	$ 37,209.16	$ 137,112.81	$ 1,939.64
WNA Revenue	JAN 2025	$ (70,415.17)	$ 2,435.84	$ (138,248.38)	$ 216.83
WNA Revenue	FEB 2025	$ (33,921.22)	$ (678.21)	$ (166,014.26)	$ (392.61)
WNA Revenue	MAR 2025	$ 95,863.33	$ 66,728.53	$ 366,474.48	$ 2,263.17
WNA Revenue	APR 2025	$ 105,405.45	$ 89,170.60	$ 523,090.58	$ 4,396.14
WNA Revenue	MAY 2025	$ 43,392.12	$ 47,012.17	$ 256,303.36	$ 1,546.22
WNA Revenue	JUN 2025	$ (867.35)	$ 621.37	$ 5,917.97	$ (5.38)
WNA Revenue	JUL 2025	$ (131.64)	$ (54.50)	$ 465.92	$ -
WNA Revenue	AUG 2025	$ (205.32)	$ (1.92)	$ 179.20	$ (2.30)
WNA Revenue	SEP 2025	$ -		$ (16.13)	
WNA Revenue	OCT 2025	$ 8,819.52	$ 2,869.69	$ 52,705.31	$ 939.45
WNA Revenue	NOV 2025	$ (45,981.82)	$ (26,347.96)	$ (68,105.62)	$ (1,101.61)
WNA Revenue	DEC 2025	$ (174,681.50)	$ (89,060.25)	$ (505,686.66)	$ (4,055.65)
WNA Revenue	JAN 2026	$ (140,634.92)	$ (65,260.38)	$ (474,291.39)	$ (5,383.13)

WNA Summary Report

Revenue Month NOV 2022 - JAN 2026
Rate Category Rate RT

	Revenue Month	GC	GN	GS	GW
WNA Revenue	NOV 2022	$ 24,459.87	$ 11,692.80	$ 89,864.16	$ 100.63
WNA Revenue	DEC 2022	$ 15,293.85	$ 14,894.01	$ 39,173.41	$ 149.82
WNA Revenue	JAN 2023	$ 90,162.03	$ 54,664.96	$ 336,989.65	$ 707.24
WNA Revenue	FEB 2023	$ 123,661.03	$ 73,979.78	$ 698,407.74	$ 1,541.20
WNA Revenue	MAR 2023	$ 89,997.96	$ 78,129.56	$ 584,684.80	$ 1,678.37
WNA Revenue	APR 2023	$ 58,730.40	$ 37,668.47	$ 259,142.60	$ 157.04
WNA Revenue	MAY 2023	$ (2,155.31)	$ 6,028.32	$ 38,867.32	$ 37.52
WNA Revenue	JUN 2023	$ (89.51)	$ 2.50	$ (362.75)	$ (29.51)
WNA Revenue	JUL 2023	$ (7.50)	$ 1.98	$ (16.77)	
WNA Revenue	AUG 2023		$ (12.01)	$ (19.53)	
WNA Revenue	SEP 2023	$ (1.01)	$ (8.50)	$ (14.49)	
WNA Revenue	OCT 2023	$ 235.65	$ 5,987.68	$ 13,632.78	$ 42.40
WNA Revenue	NOV 2023	$ 9,034.57	$ 34,093.52	$ 63,887.15	$ 387.16
WNA Revenue	DEC 2023	$ 27,829.49	$ 43,890.92	$ 114,516.84	$ 1,098.97
WNA Revenue	JAN 2024	$ 115,593.82	$ 93,001.47	$ 547,300.23	$ 2,782.82
WNA Revenue	FEB 2024	$ 116,499.82	$ 115,651.63	$ 588,301.58	$ 1,518.30
WNA Revenue	MAR 2024	$ 157,322.21	$ 143,910.64	$ 758,838.76	$ 2,099.03
WNA Revenue	APR 2024	$ 59,771.86	$ 59,814.75	$ 300,186.24	$ 994.38
WNA Revenue	MAY 2024	$ 39,896.30	$ 47,899.31	$ 150,061.56	$ 644.46
WNA Revenue	JUN 2024	$ 799.31	$ 2,854.37	$ 10,027.08	
WNA Revenue	JUL 2024	$ 72.37	$ (255.17)	$ (126.34)	
WNA Revenue	AUG 2024	$ 108.25	$ (8.80)	$ 116.89	
WNA Revenue	SEP 2024	$ (9.83)	$ (168.51)	$ 2.07	
WNA Revenue	OCT 2024	$ 9,409.26	$ 12,030.68	$ 37,598.40	$ 271.77
WNA Revenue	NOV 2024	$ 58,172.84	$ 48,570.89	$ 233,975.76	$ 633.06
WNA Revenue	DEC 2024	$ (6,541.82)	$ 35,421.58	$ 99,463.21	$ 477.80
WNA Revenue	JAN 2025	$ (29,302.30)	$ 8,669.56	$ (106,032.56)	$ (12.40)
WNA Revenue	FEB 2025	$ (26,156.95)	$ (1,103.99)	$ (112,628.44)	$ (119.05)
WNA Revenue	MAR 2025	$ 56,418.05	$ 54,608.27	$ 264,742.02	$ 382.60
WNA Revenue	APR 2025	$ 59,000.85	$ 85,635.01	$ 366,856.90	$ 1,380.03
WNA Revenue	MAY 2025	$ 35,032.34	$ 49,872.33	$ 167,875.63	$ 471.64
WNA Revenue	JUN 2025	$ (474.50)	$ (143.35)	$ 2,460.60	$ (2.08)
WNA Revenue	JUL 2025	$ 0.53	$ (95.24)	$ (15.50)	
WNA Revenue	AUG 2025	$ (1.56)	$ -	$ (23.79)	
WNA Revenue	SEP 2025	$ 10.88	$ (83.86)	$ (62.11)	
WNA Revenue	OCT 2025	$ 5,721.93	$ 4,203.30	$ 18,918.82	$ 302.49
WNA Revenue	NOV 2025	$ (38,435.89)	$ (27,319.28)	$ (51,940.62)	$ (350.37)
WNA Revenue	DEC 2025	$ (130,627.54)	$ (80,341.25)	$ (419,366.87)	$ (941.51)
WNA Revenue	JAN 2026	$ (87,831.16)	$ (75,465.76)	$ (382,461.40)	$ (1,617.75)

WNA Summary Report

Revenue Month NOV 2022 - JAN 2026
Rate Category Rate R

	Revenue Month	GC	GN	GS	GW
WNA Revenue	NOV 2022	$ 292,834.42	$ 193,117.08	$ 467,203.65	$ 1,546.00
WNA Revenue	DEC 2022	$ 221,585.03	$ 219,770.14	$ 203,663.06	$ 1,976.67
WNA Revenue	JAN 2023	$ 1,185,590.07	$ 851,807.82	$ 1,800,063.94	$ 14,145.62
WNA Revenue	FEB 2023	$ 1,641,062.19	$ 1,195,374.82	$ 3,783,422.17	$ 25,592.06
WNA Revenue	MAR 2023	$ 1,238,929.53	$ 1,163,387.83	$ 3,128,940.70	$ 33,382.91
WNA Revenue	APR 2023	$ 736,202.14	$ 582,705.76	$ 1,371,379.32	$ 3,917.93
WNA Revenue	MAY 2023	$ (12,628.18)	$ 70,298.10	$ 183,108.61	$ (71.05)
WNA Revenue	JUN 2023	$ (991.88)	$ (308.04)	$ (1,074.37)	$ (304.00)
WNA Revenue	JUL 2023	$ (131.59)	$ (425.25)	$ (211.84)	$ 1.00
WNA Revenue	AUG 2023	$ 3.90	$ (60.04)	$ 38.32	$ 59.01
WNA Revenue	SEP 2023	$ 114.77	$ (66.05)	$ (82.06)	$ 7.50
WNA Revenue	OCT 2023	$ 4,511.63	$ 79,335.97	$ 60,541.20	$ 549.05
WNA Revenue	NOV 2023	$ 94,337.48	$ 433,459.86	$ 303,974.32	$ 7,163.05
WNA Revenue	DEC 2023	$ 284,959.66	$ 625,581.76	$ 561,477.20	$ 19,493.44
WNA Revenue	JAN 2024	$ 1,308,532.14	$ 1,026,093.06	$ 2,524,516.82	$ 46,699.85
WNA Revenue	FEB 2024	$ 1,310,437.47	$ 1,440,041.73	$ 2,858,868.87	$ 29,786.46
WNA Revenue	MAR 2024	$ 1,779,073.84	$ 1,812,988.67	$ 3,718,201.17	$ 40,114.68
WNA Revenue	APR 2024	$ 718,578.11	$ 724,844.39	$ 1,493,090.36	$ 17,900.41
WNA Revenue	MAY 2024	$ 462,227.19	$ 615,082.09	$ 771,023.69	$ 13,907.45
WNA Revenue	JUN 2024	$ 11,722.23	$ 23,922.03	$ 50,196.60	$ (241.22)
WNA Revenue	JUL 2024	$ 182.40	$ (1,867.85)	$ 476.08	$ (29.52)
WNA Revenue	AUG 2024	$ (191.98)	$ (317.38)	$ (377.76)	$ (4.65)
WNA Revenue	SEP 2024	$ 37.26	$ (528.25)	$ 46.02	$ (0.01)
WNA Revenue	OCT 2024	$ 102,100.68	$ 156,271.87	$ 193,124.04	$ 5,427.76
WNA Revenue	NOV 2024	$ 622,364.19	$ 658,257.38	$ 1,232,640.51	$ 13,537.88
WNA Revenue	DEC 2024	$ (68,557.95)	$ 377,497.90	$ 531,890.21	$ 8,264.65
WNA Revenue	JAN 2025	$ (313,316.84)	$ 75,555.01	$ (572,283.13)	$ (720.79)
WNA Revenue	FEB 2025	$ (284,244.52)	$ (3,742.98)	$ (592,884.47)	$ (1,352.18)
WNA Revenue	MAR 2025	$ 570,520.49	$ 739,924.35	$ 1,443,243.52	$ 7,886.43
WNA Revenue	APR 2025	$ 638,519.90	$ 898,685.26	$ 1,944,352.03	$ 21,717.40
WNA Revenue	MAY 2025	$ 377,305.33	$ 555,172.23	$ 887,784.10	$ 6,734.09
WNA Revenue	JUN 2025	$ (2,162.16)	$ (1,088.06)	$ 12,975.69	$ (156.63)
WNA Revenue	JUL 2025	$ (86.46)	$ (3,910.10)	$ (729.34)	$ 0.52
WNA Revenue	AUG 2025	$ (91.62)	$ (280.28)	$ (116.69)	
WNA Revenue	SEP 2025	$ (61.11)	$ (750.17)	$ (102.97)	$ (25.88)
WNA Revenue	OCT 2025	$ 69,534.83	$ 54,570.89	$ 101,901.27	$ 2,268.43
WNA Revenue	NOV 2025	$ (350,977.07)	$ (316,267.54)	$ (256,300.26)	$ (4,802.05)
WNA Revenue	DEC 2025	$ (1,120,841.15)	$ (890,365.43)	$ (2,066,601.38)	$ (15,207.86)
WNA Revenue	JAN 2026	$ (787,940.36)	$ (584,956.23)	$ (1,912,472.20)	$ (24,848.94)

WNA Summary Report

Revenue Month NOV 2022 - JAN 2026
Rate Category Rate N

	Revenue Month	GC	GN	GS	GW
WNA Revenue	NOV 2022	$ 80,507.48	$ 35,208.24	$ 153,872.65	$ 663.54
WNA Revenue	DEC 2022	$ 67,454.96	$ 41,045.90	$ 86,656.02	$ 2,445.27
WNA Revenue	JAN 2023	$ 392,846.80	$ 172,348.52	$ 575,062.40	$ 5,945.39
WNA Revenue	FEB 2023	$ 475,579.99	$ 234,741.92	$ 1,421,860.68	$ 20,565.88
WNA Revenue	MAR 2023	$ 402,850.43	$ 210,853.45	$ 1,153,680.99	$ 24,570.70
WNA Revenue	APR 2023	$ 163,197.34	$ 89,273.61	$ 490,815.79	$ 3,067.02
WNA Revenue	MAY 2023	$ 26,685.57	$ 25,009.14	$ 76,330.46	$ (830.06)
WNA Revenue	JUN 2023	$ (2,072.76)	$ (581.40)	$ (1,407.16)	$ (20.64)
WNA Revenue	JUL 2023	$ 1,516.37	$ 72.36	$ (116.47)	
WNA Revenue	AUG 2023	$ (38.83)	$ 50.36	$ 315.95	$ 8.41
WNA Revenue	SEP 2023	$ (10.31)	$ (1.11)	$ 747.92	
WNA Revenue	OCT 2023	$ 8,045.68	$ 19,669.00	$ 20,200.04	$ 191.64
WNA Revenue	NOV 2023	$ 23,949.24	$ 64,727.23	$ 92,391.01	$ 2,764.38
WNA Revenue	DEC 2023	$ 82,485.76	$ 93,887.60	$ 156,491.06	$ 13,788.77
WNA Revenue	JAN 2024	$ 352,160.55	$ 217,851.71	$ 848,483.22	$ 27,814.61
WNA Revenue	FEB 2024	$ 333,802.89	$ 226,677.93	$ 920,317.11	$ 21,422.27
WNA Revenue	MAR 2024	$ 451,274.29	$ 290,431.83	$ 1,207,716.02	$ 25,755.38
WNA Revenue	APR 2024	$ 226,145.55	$ 150,432.67	$ 475,638.96	$ 8,805.10
WNA Revenue	MAY 2024	$ 116,439.47	$ 88,622.58	$ 230,558.99	$ 8,246.67
WNA Revenue	JUN 2024	$ 17,356.83	$ 12,268.23	$ 22,228.48	$ (105.16)
WNA Revenue	JUL 2024	$ 2,286.68	$ (482.31)	$ 714.00	$ (15.74)
WNA Revenue	AUG 2024	$ 146.27	$ 309.34	$ (1,522.90)	$ (141.24)
WNA Revenue	SEP 2024	$ (26.11)	$ (113.97)	$ (261.36)	
WNA Revenue	OCT 2024	$ 32,391.75	$ 28,616.34	$ 75,850.39	$ 3,414.80
WNA Revenue	NOV 2024	$ 134,921.27	$ 106,511.63	$ 352,140.68	$ 6,659.68
WNA Revenue	DEC 2024	$ (1,287.73)	$ 62,974.82	$ 172,574.13	$ 5,719.87
WNA Revenue	JAN 2025	$ (117,627.09)	$ 8,186.92	$ (179,488.03)	$ 612.49
WNA Revenue	FEB 2025	$ (73,206.78)	$ (645.47)	$ (215,589.41)	$ (853.94)
WNA Revenue	MAR 2025	$ 160,471.27	$ 128,493.23	$ 442,375.30	$ 5,899.90
WNA Revenue	APR 2025	$ 196,484.70	$ 157,609.43	$ 645,504.99	$ 12,890.34
WNA Revenue	MAY 2025	$ 77,532.98	$ 104,895.39	$ 334,684.13	$ 5,077.00
WNA Revenue	JUN 2025	$ (1,913.06)	$ 57.14	$ 5,905.90	$ (28.39)
WNA Revenue	JUL 2025	$ 106.32	$ (847.38)	$ (382.70)	$ -
WNA Revenue	AUG 2025	$ (22.25)	$ (227.20)	$ (208.40)	
WNA Revenue	SEP 2025	$ (13.43)	$ (107.08)	$ (112.08)	$ (23.41)
WNA Revenue	OCT 2025	$ 9,835.62	$ 4,471.51	$ 35,474.07	$ 1,965.08
WNA Revenue	NOV 2025	$ (75,577.82)	$ (44,587.40)	$ (72,418.87)	$ (3,645.32)
WNA Revenue	DEC 2025	$ (281,106.02)	$ (155,296.96)	$ (627,215.01)	$ (10,352.40)
WNA Revenue	JAN 2026	$ (268,974.35)	$ (121,357.60)	$ (632,458.53)	$ (14,571.37)

OCA-8-50

Request:

Please provide all analyses conducted by or for the Company which estimate the impact the WNA has had, or is expected to have, on customer bills since the implementation of the WNA pilot program. Please provide the requested information in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Response:

Attachment OCA-8-50 provides the analyses and reporting reflecting the impact of the WNA on customer bills since implementation of the WNA pilot program through February 2026. The information through October 2025 was previously provided in Exhibit JDT-3. Attachment OCA-8-50 includes that same information and adds the reporting, in draft form, for the period November 2025 through February 2026.

The file provides monthly WNA data, including billed WNA revenue adjustments, billed WNA volume adjustments, total bill counts, bill counts with WNA charges, and bill counts with WNA credits. The Company did not prepare additional analyses responsive to this request.

Prepared by or under the supervision of: John D. Taylor

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Total Number of Bills	657,848	690,784	702,630	637,189	757,679	644,611	723,767
R/RT and N/NT	Number of Bills with WNA	494,845	335,446	609,400	605,793	709,079	588,357	503,561
R/RT and N/NT	Billed WNA Volume Adj (ccf)	3,349,172	2,246,101	13,453,826	24,268,267	20,479,847	9,423,352	1,105,684
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 1,536,159	$ 1,021,184	$ 6,152,516	$ 10,999,357	$ 9,194,818	$ 4,311,784	$ 487,940
R/RT	Total Number of Bills	591,744	621,058	631,171	573,017	680,249	580,105	650,634
R/RT	Number of Bills with WNA	447,992	301,310	550,669	547,010	639,251	532,148	455,315
R/RT	Billed WNA Volume Adj (ccf)	2,153,568	1,439,549	8,647,924	15,124,980	12,723,261	6,098,146	566,866
R/RT	Billed WNA Revenue Adj ($)	$ 1,080,819	$ 716,506	$ 4,334,131	$ 7,543,041	$ 6,319,132	$ 3,049,904	$ 283,485
N/NT	Total Number of Bills	66,104	69,726	71,459	64,172	77,430	64,506	73,133
N/NT	Number of Bills with WNA	46,853	34,136	58,731	58,783	69,828	56,209	48,246
N/NT	Billed WNA Volume Adj (ccf)	1,195,604	806,552	4,805,902	9,143,287	7,756,586	3,325,206	538,818
N/NT	Billed WNA Revenue Adj ($)	$ 455,340	$ 304,678	$ 1,818,385	$ 3,456,316	$ 2,875,687	$ 1,261,880	$ 204,455

Data Presented By Calendar Month

Region	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	672	952	1,120	962	805	414	164
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	583	964	820	748	734	311	164
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	692	987	1,166	998	858	447	181
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	594	982	846	800	791	341	206
UGI Gas - North	Calendar Month - Normal Heating Degree Days	837	1,130	1,313	1,154	1,027	605	303
UGI Gas - North	Calendar Month - Actual Heating Degree Days	725	1,088	1,001	878	942	459	299
UGI Gas - South	Calendar Month - Normal Heating Degree Days	632	905	1,066	911	744	365	130
UGI Gas - South	Calendar Month - Actual Heating Degree Days	555	933	775	701	673	273	129
UGI Gas - West	Calendar Month - Normal Heating Degree Days	781	1,067	1,230	1,056	896	498	220
UGI Gas - West	Calendar Month - Actual Heating Degree Days	712	1,102	948	823	876	423	249

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Bill Count Total [2]	661,595	682,807	699,952	639,135	760,059	640,522	722,158
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	495,114	263,607	612,172	607,639	710,022	583,773	246,153
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	74.8%	38.6%	87.5%	95.1%	93.4%	91.1%	34.1%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	21,005	60,755	243	92	531	311	247,613
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	3.2%	8.9%	0.0%	0.0%	0.1%	0.0%	34.3%
R/RT and N/NT	Bill Count without WNA Charges/Credits	145,476	358,445	87,537	31,404	49,506	56,438	228,392
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	22.0%	52.5%	12.5%	4.9%	6.5%	8.8%	31.6%

UGI Utilities, Inc. - Gas Division
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Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Total Number of Bills	679,115	672,095	750,421	666,627	712,202	673,107	669,970
R/RT and N/NT	Number of Bills with WNA	5,354	72	5	15	211,543	456,224	460,215
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(18,930)	723	(1,020)	1,221	568,839	2,700,175	4,775,793
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (7,892)	$ 22	$ (393)	$ 454	$ 258,355	$ 1,280,999	$ 2,267,281
R/RT	Total Number of Bills	610,673	604,474	673,177	598,915	640,299	605,796	602,536
R/RT	Number of Bills with WNA	4,668	64	1	14	187,839	412,231	413,761
R/RT	Billed WNA Volume Adj (ccf)	(6,314)	(1,522)	36	(99)	324,373	1,828,070	3,242,561
R/RT	Billed WNA Revenue Adj ($)	$ (3,158)	$ (790)	$ 10	$ (50)	$ 164,836	$ 946,337	$ 1,678,848
N/NT	Total Number of Bills	68,442	67,621	77,244	67,712	71,903	67,311	67,434
N/NT	Number of Bills with WNA	686	8	4	1	23,704	43,993	46,454
N/NT	Billed WNA Volume Adj (ccf)	(12,616)	2,245	(1,057)	1,320	244,467	872,105	1,533,232
N/NT	Billed WNA Revenue Adj ($)	$ (4,735)	$ 812	$ (402)	$ 504	$ 93,519	$ 334,662	$ 588,432

Data Presented By Calendar Month

Region	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	30	0	16	83	350	672	952
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	21	0	1	71	289	678	756
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	35	3	10	96	376	692	987
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	51	0	5	107	320	724	786
UGI Gas - North	Calendar Month - Normal Heating Degree Days	104	42	65	202	523	837	1,130
UGI Gas - North	Calendar Month - Actual Heating Degree Days	111	8	32	159	407	773	843
UGI Gas - South	Calendar Month - Normal Heating Degree Days	11	0	2	54	306	632	905
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	0	0	47	261	647	728
UGI Gas - West	Calendar Month - Normal Heating Degree Days	54	13	26	147	453	781	1,067
UGI Gas - West	Calendar Month - Actual Heating Degree Days	80	1	18	144	408	691	763

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Bill Count Total [2]	0	0	0	0	727,098	668,042	663,445
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	0	0	184,540	431,193	470,364
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	25.4%	64.5%	70.9%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	0	0	55,602	7,234	3,747
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	7.6%	1.1%	0.6%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	0	0	486,956	229,615	189,334
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	67.0%	34.4%	28.5%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Total Number of Bills	724,592	681,980	682,512	725,300	721,146	679,265	734,574
R/RT and N/NT	Number of Bills with WNA	681,099	645,482	646,595	664,738	586,262	30,534	499
R/RT and N/NT	Billed WNA Volume Adj (ccf)	17,463,903	19,299,656	25,201,442	10,508,920	6,187,180	451,727	(15,683)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 8,167,157	$ 9,077,681	$ 11,847,340	$ 4,906,085	$ 2,918,063	$ 199,054	$ (6,443)
R/RT	Total Number of Bills	651,291	613,382	613,650	652,736	648,873	611,382	660,330
R/RT	Number of Bills with WNA	614,798	583,134	583,894	601,058	531,639	27,271	314
R/RT	Billed WNA Volume Adj (ccf)	10,942,912	12,481,667	16,251,546	6,519,900	4,057,503	191,750	(2,927)
R/RT	Billed WNA Revenue Adj ($)	$ 5,664,520	$ 6,461,106	$ 8,412,549	$ 3,375,181	$ 2,100,742	$ 99,280	$ (1,548)
N/NT	Total Number of Bills	73,301	68,598	68,862	72,564	72,273	67,883	74,244
N/NT	Number of Bills with WNA	66,301	62,348	62,701	63,680	54,623	3,263	185
N/NT	Billed WNA Volume Adj (ccf)	6,520,991	6,817,989	8,949,897	3,989,020	2,129,677	259,977	(12,756)
N/NT	Billed WNA Revenue Adj ($)	$ 2,502,636	$ 2,616,575	$ 3,434,791	$ 1,530,905	$ 817,321	$ 99,773	$ (4,895)

Data Presented By Calendar Month

Region	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	1,120	994	805	414	164	30	0
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	985	815	603	341	95	4	0
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	1,166	1,031	858	447	181	35	3
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	1,026	860	648	378	111	8	0
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,313	1,193	1,027	605	303	104	42
UGI Gas - North	Calendar Month - Actual Heating Degree Days	1,133	920	754	474	157	56	8
UGI Gas - South	Calendar Month - Normal Heating Degree Days	1,066	941	744	365	130	11	0
UGI Gas - South	Calendar Month - Actual Heating Degree Days	944	771	559	304	82	1	0
UGI Gas - West	Calendar Month - Normal Heating Degree Days	1,230	1,091	896	498	220	54	13
UGI Gas - West	Calendar Month - Actual Heating Degree Days	1,052	879	675	420	141	36	2

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Bill Count Total [2]	731,791	680,203	676,080	730,279	728,083	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	688,451	643,676	639,931	666,340	587,492	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	94.1%	94.6%	94.7%	91.2%	80.7%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	508	3	369	899	175	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	42,832	36,524	35,780	63,040	140,416	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	5.9%	5.4%	5.3%	8.6%	19.3%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC
R/RT and N/NT	Total Number of Bills	728,175	669,948	751,839	652,863	690,188
R/RT and N/NT	Number of Bills with WNA	128	(2)	288,385	559,418	427,644
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(6,104)	(4,027)	1,723,324	8,405,258	2,957,527
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (2,527)	$ (1,704)	$ 795,006	$ 3,968,165	$ 1,388,659
R/RT	Total Number of Bills	653,863	603,292	674,662	588,776	621,163
R/RT	Number of Bills with WNA	39	(4)	259,212	508,986	385,192
R/RT	Billed WNA Volume Adj (ccf)	(1,295)	(1,207)	996,923	5,538,982	1,887,330
R/RT	Billed WNA Revenue Adj ($)	$ (675)	$ (621)	$ 516,234	$ 2,868,153	$ 977,916
N/NT	Total Number of Bills	74,312	66,656	77,177	64,087	69,025
N/NT	Number of Bills with WNA	89	2	29,173	50,432	42,452
N/NT	Billed WNA Volume Adj (ccf)	(4,809)	(2,820)	726,400	2,866,276	1,070,197
N/NT	Billed WNA Revenue Adj ($)	$ (1,852)	$ (1,082)	$ 278,772	$ 1,100,013	$ 410,743

Data Presented By Calendar Month

Region	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	16	83	350	672	952
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	12	35	278	562	957
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	10	96	376	692	987
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	19	48	315	627	1,030
UGI Gas - North	Calendar Month - Normal Heating Degree Days	65	202	523	837	1,130
UGI Gas - North	Calendar Month - Actual Heating Degree Days	43	79	406	681	1,061
UGI Gas - South	Calendar Month - Normal Heating Degree Days	2	54	306	632	905
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	25	244	516	912
UGI Gas - West	Calendar Month - Normal Heating Degree Days	26	147	453	781	1,067
UGI Gas - West	Calendar Month - Actual Heating Degree Days	25	74	388	655	1,021

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC
R/RT and N/NT	Bill Count Total [2]	0	0	766,628	629,649	703,828
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	323,925	546,068	319,684
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	42.3%	86.7%	45.4%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	1,074	38	107,240
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.1%	0.0%	15.2%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	441,629	83,543	276,904
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	57.6%	13.3%	39.3%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 JAN	2025 FEB	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL
R/RT and N/NT	Total Number of Bills	742,545	647,127	716,321	709,895	709,872	713,760	735,660
R/RT and N/NT	Number of Bills with WNA	415,714	426,511	522,521	637,555	484,433	19,813	57
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(3,100,199)	(3,255,501)	9,366,210	12,277,590	6,286,389	45,793	(12,712)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (1,431,770)	$ (1,513,534)	$ 4,406,295	$ 5,750,700	$ 2,950,691	$ 21,098	$ (5,680)
R/RT	Total Number of Bills	667,793	582,802	644,559	639,457	638,553	642,608	661,589
R/RT	Number of Bills with WNA	373,211	384,270	470,537	576,765	439,236	17,805	9
R/RT	Billed WNA Volume Adj (ccf)	(1,812,212)	(1,975,349)	6,060,757	7,757,939	4,018,315	20,549	(10,066)
R/RT	Billed WNA Revenue Adj ($)	$ (937,443)	$ (1,022,233)	$ 3,137,726	$ 4,016,147	$ 2,080,248	$ 11,410	$ (4,836)
N/NT	Total Number of Bills	74,752	64,325	71,762	70,438	71,319	71,152	74,071
N/NT	Number of Bills with WNA	42,503	42,241	51,984	60,790	45,197	2,008	48
N/NT	Billed WNA Volume Adj (ccf)	(1,287,987)	(1,280,152)	3,305,453	4,519,651	2,268,074	25,244	(2,646)
N/NT	Billed WNA Revenue Adj ($)	$ (494,327)	$ (491,302)	$ 1,268,569	$ 1,734,552	$ 870,443	$ 9,688	$ (844)

Data Presented By Calendar Month

Region	Reporting Item	2025 JAN	2025 FEB	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	1,120	962	805	414	164	30	0
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	1,216	941	604	359	160	20	0
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	1,166	998	858	447	181	35	3
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	1,266	999	667	425	219	31	3
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,313	1,154	1,027	605	303	104	42
UGI Gas - North	Calendar Month - Actual Heating Degree Days	1,364	1,103	748	496	318	61	18
UGI Gas - South	Calendar Month - Normal Heating Degree Days	1,066	911	744	365	130	11	0
UGI Gas - South	Calendar Month - Actual Heating Degree Days	1,173	891	553	318	114	15	0
UGI Gas - West	Calendar Month - Normal Heating Degree Days	1,230	1,056	896	498	220	54	13
UGI Gas - West	Calendar Month - Actual Heating Degree Days	1,310	1,019	698	464	268	39	1

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 JAN	2025 FEB	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL
R/RT and N/NT	Bill Count Total [2]	730,792	653,438	709,220	714,780	708,205	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	32,920	22,900	535,815	638,314	465,363	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	4.5%	3.5%	75.5%	89.3%	65.7%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	386,799	388,472	26	2,067	8,174	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	52.9%	59.5%	0.0%	0.3%	1.2%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	311,073	242,066	173,379	74,399	234,668	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	42.6%	37.0%	24.4%	10.4%	33.1%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division **Attachment OCA-8-50**

Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 AUG	2025 SEP	2025 OCT	2025 NOV	2025 DEC	2026 JAN	2026 FEB
R/RT and N/NT	Total Number of Bills	705,888	701,197	762,059	639,945	723,737	694,265	681,876
R/RT and N/NT	Number of Bills with WNA	18	(25)	281,147	470,187	560,169	484,422	626,394
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(2,385)	(3,696)	803,710	(2,616,148)	(11,760,195)	(10,099,264)	(25,909,782)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (1,002)	$ (1,347)	$ 374,502	$ (1,384,160)	$ (6,571,747)	$ (5,580,525)	$ (14,440,359)
R/RT	Total Number of Bills	635,194	631,059	684,790	577,241	651,153	625,372	614,222
R/RT	Number of Bills with WNA	18	(20)	253,447	424,038	503,804	434,131	563,918
R/RT	Billed WNA Volume Adj (ccf)	(1,113)	(2,077)	497,914	(1,794,059)	(7,464,057)	(6,092,655)	(16,239,557)
R/RT	Billed WNA Revenue Adj ($)	$ (514)	$ (1,075)	$ 257,422	$ (1,046,393)	$ (4,724,293)	$ (3,857,594)	$ (10,281,879)
N/NT	Total Number of Bills	70,694	70,138	77,269	62,704	72,584	68,893	67,654
N/NT	Number of Bills with WNA	-	(5)	27,700	46,149	56,365	50,291	62,476
N/NT	Billed WNA Volume Adj (ccf)	(1,272)	(1,619)	305,796	(822,089)	(4,296,138)	(4,006,609)	(9,670,225)
N/NT	Billed WNA Revenue Adj ($)	$ (488)	$ (272)	$ 117,080	$ (337,766)	$ (1,847,454)	$ (1,722,932)	$ (4,158,480)

Data Presented By Calendar Month

Region	Reporting Item	2025 AUG	2025 SEP	2025 OCT	2025 NOV	2025 DEC	2026 JAN	2026 FEB
UGI Gas - COMPOSITE	Calendar Month - Normal Heating Degree Days	16	83	326	670	918	1,099	915
UGI Gas - COMPOSITE	Calendar Month - Actual Heating Degree Days	24	17	365	694	1,128	1,266	1,021
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	10	96	341	686	942	1,132	945
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	43	38	398	718	1,174	1,285	1,058
UGI Gas - North	Calendar Month - Normal Heating Degree Days	65	202	473	813	1,063	1,273	1,080
UGI Gas - North	Calendar Month - Actual Heating Degree Days	116	175	530	892	1,309	1,468	1,154
UGI Gas - South	Calendar Month - Normal Heating Degree Days	2	54	279	624	868	1,039	858
UGI Gas - South	Calendar Month - Actual Heating Degree Days	11	8	309	630	1,062	1,199	973
UGI Gas - West	Calendar Month - Normal Heating Degree Days	26	147	429	766	1,018	1,204	1,000
UGI Gas - West	Calendar Month - Actual Heating Degree Days	65	87	469	808	1,219	1,375	1,063

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 AUG	2025 SEP	2025 OCT	2025 NOV	2025 DEC	2026 JAN	2026 FEB
R/RT and N/NT	Bill Count Total [2]	0	0	770,361	624,353	728,085	719,129	655,883
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	225,621	460	12	1,438	339
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	29.3%	0.1%	0.0%	0.2%	0.1%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	83,898	445,913	584,040	506,237	601,851
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	10.9%	71.4%	80.2%	70.4%	91.8%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	460,842	177,980	145,033	211,454	53,693
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	59.8%	28.5%	19.9%	29.4%	8.2%

Should update again before filing

I&E-RR-6-D

Request:

Identify the actual return on equity earned by UGI Utilities, Inc. – Gas Division, and separately, its parent company UGI Utilities, Inc. for calendar years 2023, 2024, and 2025.

Response:

UGI Utilities, Inc. uses a fiscal year (twelve months ended September 30) to prepare its financial statements and has presented information in this proceeding on a fiscal year basis.

Please see the calculated actual returns on equity at Attachment I&E-RR-6-D.

Prepared by or under the supervision of: Dylan W. D'Ascendis

UGI Utilities, Inc. - Gas Division
Actual Return on Equity
Twelve Months Ended September 30, 2025, 2024 and 2023

		Fiscal 2025	Fiscal 2024	Fiscal 2023
Rate of Return on Equity				
	UGI Utilities, Inc.	10.5%	11.5%	11.7%
(a)	UGI Utilities, Inc. - Gas Division	10.4%	11.2%	11.4%
(b)	UGI Utilities, Inc. - Electric Division	6.2%	6.9%	2.2%

(a) Fiscal 2024 and Fiscal 2023 are from the Quarterly Earnings Reports previously provided to the Commission by UGI Gas for those periods. UGI Gas was not required to file a report for 12 months ended September 2025; however, the return on equity shown for Fiscal 2025 is calculated in the same manner as the Fiscal 2024 and Fiscal 2023 Quarterly Earnings Report calculations.

(b) Fiscal 2025 and Fiscal 2024 are from Quarterly Earnings Reports previously provided to the Commission for UGI Electric (related to distribution only, excluding transmission). UGI Electric was not required to file a report for 12 months ended September 2023; however, the return on equity shown for Fiscal 2023 is calculated in the same manner as the Fiscal 2025 and Fiscal 2024 Quarterly Earnings Report calculations.

UGI Utilities, Inc. - Gas Division
Actual Return on Equity
Twelve Months Ended September 30, 2025, 2024 and 2023

		Fiscal 2025	Fiscal 2024	Fiscal 2023
Rate of Return on Equity				
	UGI Utilities, Inc.	10.5%	11.5%	11.7%
(a)	UGI Utilities, Inc. - Gas Division	10.4%	11.2%	11.4%
(b)	UGI Utilities, Inc. - Electric Division	6.2%	6.9%	2.2%

(a) Fiscal 2024 and Fiscal 2023 are from the Quarterly Earnings Reports previously provided to the Commission by UGI Gas for those periods. UGI Gas was not required to file a report for 12 months ended September 2025; however, the return on equity shown for Fiscal 2025 is calculated in the same manner as the Fiscal 2024 and Fiscal 2023 Quarterly Earnings Report calculations.

(b) Fiscal 2025 and Fiscal 2024 are from Quarterly Earnings Reports previously provided to the Commission for UGI Electric (related to distribution only, excluding transmission). UGI Electric was not required to file a report for 12 months ended September 2023; however, the return on equity shown for Fiscal 2023 is calculated in the same manner as the Fiscal 2025 and Fiscal 2024 Quarterly Earnings Report calculations.

CAUSE-PA Statement 1, Cicero
Appendix C

Exhibits Cicero C-1 through C-6

2026 Poverty Guidelines: 48 Contiguous States (all states except Alaska and Hawaii)

Dollars Per Year

Household/ Family Size	50%	75%	100%	125%	130%	133%	135%	138%	150%	175%	180%	185%
1	7,980.00	11,970.00	15,960.00	19,950.00	20,748.00	21,226.80	21,546.00	22,024.80	23,940.00	27,930.00	28,728.00	29,526.00
2	10,820.00	16,230.00	21,640.00	27,050.00	28,132.00	28,781.20	29,214.00	29,863.20	32,460.00	37,870.00	38,952.00	40,034.00
3	13,660.00	20,490.00	27,320.00	34,150.00	35,516.00	36,335.60	36,882.00	37,701.60	40,980.00	47,810.00	49,176.00	50,542.00
4	16,500.00	24,750.00	33,000.00	41,250.00	42,900.00	43,890.00	44,550.00	45,540.00	49,500.00	57,750.00	59,400.00	61,050.00
5	19,340.00	29,010.00	38,680.00	48,350.00	50,284.00	51,444.40	52,218.00	53,378.40	58,020.00	67,690.00	69,624.00	71,558.00
6	22,180.00	33,270.00	44,360.00	55,450.00	57,668.00	58,998.80	59,886.00	61,216.80	66,540.00	77,630.00	79,848.00	82,066.00
7	25,020.00	37,530.00	50,040.00	62,550.00	65,052.00	66,553.20	67,554.00	69,055.20	75,060.00	87,570.00	90,072.00	92,574.00
8	27,860.00	41,790.00	55,720.00	69,650.00	72,436.00	74,107.60	75,222.00	76,893.60	83,580.00	97,510.00	100,296.00	103,082.00
9	30,700.00	46,050.00	61,400.00	76,750.00	79,820.00	81,662.00	82,890.00	84,732.00	92,100.00	107,450.00	110,520.00	113,590.00
10	33,540.00	50,310.00	67,080.00	83,850.00	87,204.00	89,216.40	90,558.00	92,570.40	100,620.00	117,390.00	120,744.00	124,098.00
11	36,380.00	54,570.00	72,760.00	90,950.00	94,588.00	96,770.80	98,226.00	100,408.80	109,140.00	127,330.00	130,968.00	134,606.00
12	39,220.00	58,830.00	78,440.00	98,050.00	101,972.00	104,325.20	105,894.00	108,247.20	117,660.00	137,270.00	141,192.00	145,114.00
13	42,060.00	63,090.00	84,120.00	105,150.00	109,356.00	111,879.60	113,562.00	116,085.60	126,180.00	147,210.00	151,416.00	155,622.00
14	44,900.00	67,350.00	89,800.00	112,250.00	116,740.00	119,434.00	121,230.00	123,924.00	134,700.00	157,150.00	161,640.00	166,130.00

Household/ Family Size	200%	225%	250%	275%	300%	325%	350%	375%	400%	500%	600%	700%
1	31,920.00	35,910.00	39,900.00	43,890.00	47,880.00	51,870.00	55,860.00	59,850.00	63,840.00	79,800.00	95,760.00	111,720.00
2	43,280.00	48,690.00	54,100.00	59,510.00	64,920.00	70,330.00	75,740.00	81,150.00	86,560.00	108,200.00	129,840.00	151,480.00
3	54,640.00	61,470.00	68,300.00	75,130.00	81,960.00	88,790.00	95,620.00	102,450.00	109,280.00	136,600.00	163,920.00	191,240.00
4	66,000.00	74,250.00	82,500.00	90,750.00	99,000.00	107,250.00	115,500.00	123,750.00	132,000.00	165,000.00	198,000.00	231,000.00
5	77,360.00	87,030.00	96,700.00	106,370.00	116,040.00	125,710.00	135,380.00	145,050.00	154,720.00	193,400.00	232,080.00	270,760.00
6	88,720.00	99,810.00	110,900.00	121,990.00	133,080.00	144,170.00	155,260.00	166,350.00	177,440.00	221,800.00	266,160.00	310,520.00
7	100,080.00	112,590.00	125,100.00	137,610.00	150,120.00	162,630.00	175,140.00	187,650.00	200,160.00	250,200.00	300,240.00	350,280.00
8	111,440.00	125,370.00	139,300.00	153,230.00	167,160.00	181,090.00	195,020.00	208,950.00	222,880.00	278,600.00	334,320.00	390,040.00
9	122,800.00	138,150.00	153,500.00	168,850.00	184,200.00	199,550.00	214,900.00	230,250.00	245,600.00	307,000.00	368,400.00	429,800.00
10	134,160.00	150,930.00	167,700.00	184,470.00	201,240.00	218,010.00	234,780.00	251,550.00	268,320.00	335,400.00	402,480.00	469,560.00
11	145,520.00	163,710.00	181,900.00	200,090.00	218,280.00	236,470.00	254,660.00	272,850.00	291,040.00	363,800.00	436,560.00	509,320.00
12	156,880.00	176,490.00	196,100.00	215,710.00	235,320.00	254,930.00	274,540.00	294,150.00	313,760.00	392,200.00	470,640.00	549,080.00
13	168,240.00	189,270.00	210,300.00	231,330.00	252,360.00	273,390.00	294,420.00	315,450.00	336,480.00	420,600.00	504,720.00	588,840.00
14	179,600.00	202,050.00	224,500.00	246,950.00	269,400.00	291,850.00	314,300.00	336,750.00	359,200.00	449,000.00	538,800.00	628,600.00

Note: Each individual program--e.g., SNAP, Medicaid--determines how to round various multiples of the poverty guidelines, what income is to be included, and how the eligibility unit is defined. For more information about the poverty guidelines visit: http://aspe.hhs.gov/poverty.

Source: U.S. Department of Health and Human Services, Office of the Assistant Secretary for Planning and Evaluation.

Energy Assistance Summary (EASUM)

8/23/2025 - 4/2/2026

CAUSE-PA St. 1
Appendix C, Exhibit C-2

STATE WIDE

Cash Demographic Report (LIH660-R01)

	ITEM	COUNT	AMOUNT	%	AVG
HOUSING	Owner	97,022	$25,845,897	40	$266
	Renter	110,636	$31,732,810	45	$287
	RenterWithHeat	2,471	$679,989	1	$275
	SubsidizedWithHeat	58	$17,224	0	$297
	SubsidizedNoHeat	31,022	$9,771,332	13	$315
	Roomer	194	$66,642	0	$344
	Other	3,421	$1,179,995	1	$345
RACE	AmericanIndian	752	$255,144	0	$339
	Other	21,369	$5,942,509	9	$278
	NativeHawaiian	437	$136,665	0	$313
	Black	54,142	$16,020,868	22	$296
	White	158,948	$44,454,716	65	$280
	Asian	4,868	$1,266,319	2	$260
	Unknown	4,308	$1,217,668	2	$283
DISABLED	YES	66,316	$14,839,327	27	$224
	NO	178,508	$54,454,562	73	$305
AGE 60 & ABV	YES	114,683	$26,482,140	47	$231
	NO	130,141	$42,811,749	53	$329
AGE 5 & BLW	YES	37,557	$11,524,524	15	$307
	NO	207,267	$57,769,365	85	$279
PAY_TYPE	DIRECT	3,248	$985,184	1	$303
	PROVIDER	243,132	$68,656,576	99	$282
REFUNDS		6,318	$1,339,882		$212

AVERAGE HOUSEHOLD SIZE: 3

* Counts, Amounts ($), % and AVG from HOUSING, RACE, DISABLED, OVER-60 and INCOME RANGE category are from Regular payments only

** Counts, Amounts ($), % and AVG from PAY_TYPE category are from All Payment Types (Regular, Reissue, Secondpay, Underpay and Extraordinary)

*** Counts, Amounts ($), % and AVG from PAYMENT_SENT category are from All Payment Types (Regular, Reissue, Secondpay, Underpay and Extraordinary)

	ITEM	COUNT	AMOUNT	%	AVG
PAYMENT SENT	Electric	88,785	$26,102,374	36	$294
	FuelOil	40,851	$11,532,809	17	$282
	Coal	1,187	$314,636	0	$265
	NaturalGas	100,412	$27,568,856	41	$275
	Kerosene	1,820	$509,755	1	$280
	Propane	10,133	$2,757,300	4	$272
	WoodOrOther	1,136	$358,282	0	$315
	BlendedFuel	500	$149,877	0	$300
INCOME RANGE	0 - 999	11,386	$11,347,271	5	$997
	1000 - 1999	1,889	$1,886,389	1	$999
	2000 - 2999	1,868	$1,817,687	1	$973
	3000 - 3999	2,079	$1,698,936	1	$817
	4000 - 4999	2,145	$1,560,133	1	$727
	5000 - 5999	2,139	$1,251,354	1	$585
	6000 - 6999	2,459	$1,260,226	1	$512
	7000 - 7999	2,874	$1,279,721	1	$445
	8000 - 8999	3,283	$1,282,233	1	$391
	9000 - 9999	4,004	$1,361,575	2	$340
	10000 - 10999	5,345	$1,585,124	2	$297
	11000 - 11999	22,523	$5,746,238	9	$255
	12000 - 12999	23,227	$5,198,580	9	$224
	13000 - 13999	10,155	$2,110,112	4	$208
	14000 - 14999	10,838	$2,183,941	4	$202
	15000 - 15999	10,687	$2,138,948	4	$200
	16000 - 16999	10,749	$2,149,821	4	$200
	17000 - 17999	11,425	$2,285,000	5	$200
	18000 - 18999	11,361	$2,272,200	5	$200
	19000 - 19999	10,958	$2,191,600	4	$200
	> 19999	83,428	$16,685,600	34	$200
PAYMENT TYPE	Regular	244,824	$69,293,889		$283
	Reissue	222	$44,273		$199
	Secondpay	1,227	$282,389		$230
	Underpay	48	$10,270		$214
	Extraordinary	59	$10,939		$185
TOTAL PMT		246,380	$69,641,760		$283
RECOUPMENTS		414	$87,529		$211
NET PAID			$69,554,231		
PMT SUB TYPE	APD	0	$0		$0
	STD	246,380	$69,641,760		$283

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
1	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	UGI Gas's WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. The Company recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.	There is limited connection between the WNA and cost causation. The WNA assumes that UGI is entitled to recover its revenue requirement regardless of the usage or throughput of its customers due to variations in weather even though UGI is in a weather sensitive business. While it is designed to ensure that UGI recovers its authorized revenue requirement and fixed costs, it does not align cost causation with cost recovery because the WNA is applied to the variable charge in a customer's bill. The WNA also has the likelihood of disincentivizing effective management because the WNA charges customers based on normalized weather sensitive usage rather than actual weather sensitive usage.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
2	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company's gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company's ability to make prudent investments necessary to maintain safe and reliable service.	It does not. Since the WNA assesses charges on customers for throughput not consumed, due to weather conditions (i.e., customers are charged when the weather is warmer than normal when they use less of the systems' capacity – and provides them with a credit in months when they use more of the system's capacity, i.e, they receive a credit when the weather is colder than normal and they use more of the system's capacity) the WNA does not support fixed capacity utilization.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated c onsumption levels.	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer's anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 10-year average rather than a 15-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions. Please refer to UGI Gas Exhibit JDT-2.	The WNA does not meet this criterion. because the WNA generates revenue for UGI only when consumption is less than projected – and therefore demand is less than anticipated – it does not, in fact, reflect the level of demand that is associated with customers' anticipated usage. Furthermore, by design, the WNA is targeted to meet the revenue requirement at a fixed point in time. While that design is based on anticipated consumption at the end of the FPFTY and will change with each rate case, it fixes that revenue requirement as an entitlement despite projections of revenue loss based on weather.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	UGI Gas's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.	The WNA may lead to intraclass cost shifting to the extent that customers with lower use may have a larger percentage of their total bill be weather sensitive than customers with more use. I agree that as structured it will not likely lead to interclass cost shifting.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
5	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.	The WNA does not incentivize additional energy efficiency funding and may discourage energy efficency adoption to the extent customers believe that their energy efficiency investment will be eroded.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
6	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.	The WNA does not incentivize additional energy efficiency funding and may discourage energy efficency adoption to the extent customers believe that their energy efficiency investment will be eroded.
7	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance progr ams.	In accordance with the Settlement Agreement in Docket Nos. R-2024-3052716, et al., the current WNA mechanism does not apply to low-income customers enrolled in the Company's Customer Assistance Program ("CAP").	More than 80% of UGI's low income customers are not enrolled in CAP and will bear the full brunt of WNAs that are assessed. Since the WNA is assessed during the months when bills are at their highest (in winter months due to winter usage), the assessment of a WNA during the winter compounds energy insecurity and unaffordable bills for UGI's low income customers.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
8	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.	Rates may be moderately more stable during the months that a WNA is applied given that it is assessed on a volumetric and per customer basis and seeks to normalize weather sensitve usage, however, on a long term basis there is no evidence that rates will be more stable. UGI has filed a rate case a mere 3 months after its last rate increase went into effect and there has been no showing that the presence of the WNA leads to fewer or less frequent rate cases.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
9	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months of October through April, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.	I agree that the WNA reduces weather-related variation in revenue collection for UGI, but it does this my imposing the obligation onto residential customers who are less able to bear this risk. This is especially true of UGI's low income customers whose average household income is approximately $20,000 per year.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
10	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	The WNA does not impact the Company's rate case frequency nor it effects regulatory lag.	I agree that the WNA will not reduce the frequencey of rate cases, it will merely allow the utility to collect more revenue and reduce the overall effectiveness of the regulatory paradigm, including the effectiveness of regulatory lag. The WNA increases the likelihood that UGI will collect its projected revenue and *decreases* the likelihood that it will operate efficiently between rate cases. The WNA is a surcharge that weakens all of the positive aspects of regulatory lag such as cost containment between rate cases.
11	If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).	The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through April. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.	Since the WNA has historically worked almost exclusively to the benefit of UGI given warming winters, and because UGI applies the DSIC to WNA revenue, the existence of the WNA has the effect of increasing the dollars that UGI is able to collect through its WNA. In this regard, it allows a sucharge on a surcharge.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	UGI Gas's WNA includes several consumer protections to ensure fairness and transparency, as follows:	The WNA is neither fair nor transparent because it almost always benefits the utility and it is complicated to understand. Most people do not know what a heating degree day is, how a utility's rates are set, and most people cannot follow the complicated algebraic equation need to determine their WNA charge.
		a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and outside of the deadband the WNA results in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates.	This is a protection, but in the absence of the WNA, there would be no need for a deadband. This is merely a restraint or collar on the worst outcomes of the WNA.
		b. No Cross-Subsidization: The WNA is customer-specific.	I do not agree that this is a protection because it imposes charges on customers based on normalized usage, it requires them to pay not based on what they actually used but based on what they should have used had the weather conformed to historic patterns. Because the WNA is set to achieve an overall revenue requirement for the class, it should be imposed, if at all, across the class not on an individual basis.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
		c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts.	The protections asserted by UGI are about the regulatory system that is in place, not the WNA. There is nothing inherent about the WNA that ensures regulatory oversight or reporting.
		d. Customer Transparency and Education: UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.	UGI's customer education and outreach on the WNA has improved but that improvement is a function of intervenor insistence and regulatory oversight, not that the WNA itself is understandable.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
13	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. As indicated above, UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.	It is not understandable. Customers understand that they should pay for gas distribution service they use, but do not understand that they should pay for service they do not use, which is what the WNA demands. The WNA formula is complicated and not transparent, and it is not reasonable for customers to have to understand each of the complicated concepts used to calculate this charge. It is a multvariable algebraic equation based on an abstract concept. It is in no way straight forward. The fact that UGI points to its tariff demonstrates the difficulty that any lay person would have: the tariff uses jargon and terms of art that are unique and in no way common. While UGI's education on its WNA is improving, the concept is fundamentally alien to the common understanding that you pay for what you use.

#	Statement of Policy	Company's Response (Exhibit JDT-4)	CAUSE-PA Response
14	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudency and reasonableness would have been reviewed and deemed appropriate to support reliability driven initiatives. The proposed WNA would help minimize the volatility of the recovery of these costs.	There is no basis in the record to conclude that the WNA will improve reliablity. In fact, in response to discovery, Mr. Taylor stated that the WNA is not connected to the Company's ability to provide safe and reliable service. (UGI Response to CAUSE-PA 4-7, Attached at Appendix B).

CAUSE-PA Statement No. 1
Appendix C, Exhibit C-4
Price to Compare

Source: UGI Response to CAUSE-PA 5-6

UGI UTILITIES, INC. - GAS DIVISION
Monthly Price to Compare $/Mcf
January 2023 - March 2026

	Residential	Non-Residential
Jan-23	9.1155	8.9535
Feb-23	9.1155	8.9535
Mar-23	7.7606	7.6229
Apr-23	7.7606	7.6229
May-23	7.7606	7.6229
Jun-23	7.7606	7.6229
Jul-23	7.7606	7.6229
Aug-23	7.7606	7.6229
Sep-23	7.7606	7.6229
Oct-23	7.7606	7.6229
Nov-23	7.7606	7.6229
Dec-23	4.5335	4.4535
Jan-24	4.5335	4.4535
Feb-24	4.5335	4.4535
Mar-24	4.1369	4.0640
Apr-24	4.1369	4.0640
May-24	4.1369	4.0640
Jun-24	4.6946	4.6118
Jul-24	4.6946	4.6118
Aug-24	4.6946	4.6118
Sep-24	4.6946	4.6118
Oct-24	4.6946	4.6118
Nov-24	4.6946	4.6118
Dec-24	5.8219	5.7189
Jan-25	5.8219	5.7189
Feb-25	5.8219	5.7189
Mar-25	6.8221	6.7012
Apr-25	6.8221	6.7012
May-25	6.8221	6.7012
Jun-25	6.8221	6.7012
Jul-25	6.8221	6.7012
Aug-25	6.8221	6.7012
Sep-25	6.8221	6.7012
Oct-25	6.8221	6.7012
Nov-25	6.8412	6.7091
Dec-25	6.9874	6.8524
Jan-26	6.9874	6.8524
Feb-26	6.9874	6.8524
Mar-26	7.6795	7.5311

$6.37

6.3711

Average PTC
Jan 23- Jan 26

6.3544

CAUSE-PA ST. 1
APPENDIX C, EXHIBIT C-5
RESIDENTIAL SHOPPING V. DEFAULT

UGI Utilities, Inc. - Gas Division
Residential Customers, Sales, and Commodity Supply Charges-Shopping and Default Service
January 2023 - February 2026

Source: Attachment CAUSE-PA 5-1

LINE#	(A) Month	(B) *Total Residential shopping customers	(C) *Total billed usage of Residential shopping customers (Mcf's)	(D) Total billed commodity supply charges for Residential shopping customers ($)	(E) Average Cost per Mcf Shopping Customers	(F) Total Residential default service customers	(G) Total billed usage of Residential default service customers (Mcf's)	(H) Total billed commodity supply charges for Residential default service customers ($)	(I) Average Cost per Mcf Default Service Customers	(J) Dollar Amount Difference in Average Cost per Mcf Shopping vs Default ($)	(K) Percentage Difference in Average Cost per Mcf Shopping vs Default (%)	(L) Difference in Aggregate Cost Shopping v. Default Column (J) times (C)	(M) Difference in Aggregate Cost Shopping v. Default Service Price To Compare
1	Jan-23	74,585	1,017,672	$10,480,307	$10.30	544,274	7,644,355	$69,671,561	$9.11	$1.18	13.0%	$1,205,126	$1,203,720.66
2	Feb-23	74,687	833,004	$8,635,401	$10.37	544,804	6,384,300	$58,195,067	$9.12	$1.25	13.7%	$1,042,291	$1,042,157.95
3	Mar-23	77,047	886,344	$9,111,030	$10.28	542,895	6,654,099	$56,133,147	$8.44	$1.84	21.9%	$1,633,946	$2,232,471.50
4	Apr-23	78,325	502,367	$4,729,543	$9.41	538,497	3,741,275	$29,040,150	$7.76	$1.65	21.3%	$830,123	$830,875.60
5	May-23	79,716	307,801	$2,871,165	$9.33	535,480	2,203,414	$17,099,614	$7.76	$1.57	20.2%	$482,476	$482,448.25
6	Jun-23	80,740	159,532	$1,522,435	$9.54	532,810	1,088,173	$8,442,991	$7.76	$1.78	23.0%	$284,644	$284,368.34
7	Jul-23	81,435	109,634	$1,077,666	$9.83	530,729	701,672	$5,444,379	$7.76	$2.07	26.7%	$226,996	$226,837.94
8	Aug-23	81,829	111,387	$1,106,370	$9.93	529,094	697,820	$5,414,553	$7.76	$2.17	28.0%	$242,094	$241,943.03
9	Sep-23	82,458	106,708	$1,035,909	$9.71	529,873	668,856	$5,189,962	$7.76	$1.95	25.1%	$207,915	$207,793.82
10	Oct-23	83,449	181,871	$1,681,117	$9.24	532,608	1,168,947	$9,069,644	$7.76	$1.48	19.1%	$270,014	$269,689.34
11	Nov-23	84,510	417,484	$3,662,748	$8.77	536,226	2,784,546	$21,608,997	$7.76	$1.01	13.1%	$422,933	$422,821.12
12	Dec-23	85,446	871,019	$7,425,619	$8.53	537,990	5,566,495	$36,017,806	$6.47	$2.05	31.8%	$1,789,724	$3,476,855.81
13	Jan-24	84,331	1,140,550	$9,881,161	$8.66	540,795	7,315,816	$32,694,659	$4.47	$4.19	93.9%	$4,784,001	$4,710,478.57
14	Feb-24	83,221	1,053,060	$9,092,383	$8.63	542,662	6,913,738	$31,344,096	$4.53	$4.10	90.5%	$4,318,235	$4,318,336.26
15	Mar-24	82,229	833,397	$7,118,399	$8.54	543,812	5,550,878	$24,226,697	$4.36	$4.18	95.7%	$3,481,054	$3,670,718.75
16	Apr-24	81,425	651,798	$5,546,275	$8.51	542,264	4,526,871	$18,733,143	$4.14	$4.37	105.6%	$2,848,997	$2,849,851.17
17	May-24	80,635	280,242	$2,453,487	$8.75	540,287	1,935,709	$8,009,022	$4.14	$4.62	111.6%	$1,293,981	$1,294,152.58
18	Jun-24	80,196	139,162	$1,280,614	$9.20	538,881	928,937	$4,065,190	$4.38	$4.83	110.3%	$671,615	$627,302.21
19	Jul-24	79,974	107,623	$1,036,612	$9.63	536,821	705,693	$3,322,552	$4.71	$4.92	104.6%	$529,901	$531,366.13
20	Aug-24	79,590	100,299	$971,809	$9.69	536,580	660,323	$3,099,486	$4.69	$5.00	106.4%	$501,017	$500,945.99
21	Sep-24	79,579	103,835	$996,481	$9.60	537,599	702,046	$3,294,410	$4.69	$4.90	104.5%	$509,224	$509,014.85
22	Oct-24	79,720	168,042	$1,551,287	$9.23	541,912	1,126,761	$5,289,555	$4.69	$4.54	96.6%	$762,417	$762,396.62
23	Nov-24	79,894	302,128	$2,662,949	$8.81	545,839	2,184,364	$10,254,895	$4.69	$4.12	87.7%	$1,244,556	$1,244,581.37
24	Dec-24	80,188	838,283	$7,182,269	$8.57	549,149	5,966,686	$31,070,218	$5.21	$3.36	64.5%	$2,817,091	$2,301,867.70
25	Jan-25	81,335	1,338,645	$11,610,440	$8.67	549,592	9,213,016	$53,566,274	$5.81	$2.86	49.2%	$3,827,295	$3,816,981.93
26	Feb-25	81,605	1,228,950	$10,553,534	$8.59	549,776	8,540,468	$49,719,371	$5.82	$2.77	47.5%	$3,399,055	$3,398,713.09
27	Mar-25	81,867	1,017,392	$8,735,493	$8.59	549,562	6,991,733	$43,729,853	$6.25	$2.33	37.3%	$2,372,206	$1,794,743.39
28	Apr-25	81,742	566,396	$4,961,448	$8.76	547,390	3,955,103	$26,971,102	$6.82	$1.94	28.5%	$1,099,013	$1,097,437.18
29	May-25	81,485	280,666	$2,544,775	$9.07	545,232	1,918,476	$13,088,977	$6.82	$2.24	32.9%	$629,906	$630,043.22
30	Jun-25	81,623	179,000	$1,695,838	$9.47	543,201	1,238,514	$8,448,480	$6.82	$2.65	38.9%	$474,795	$474,681.39
31	Jul-25	81,671	112,591	$1,148,554	$10.20	540,819	715,225	$4,878,657	$6.82	$3.38	49.6%	$380,553	$380,445.77
32	Aug-25	82,037	98,058	$1,035,535	$10.56	539,569	636,930	$4,344,102	$6.82	$3.74	54.8%	$366,746	$366,576.05
33	Sep-25	82,349	111,009	$1,153,684	$10.39	539,764	720,462	$4,914,363	$6.82	$3.57	52.4%	$396,479	$396,370.98
34	Oct-25	83,154	167,145	$1,667,426	$9.98	543,833	1,091,100	$7,443,559	$6.82	$3.15	46.2%	$527,153	$527,148.12
35	Nov-25	83,995	407,192	$3,819,383	$9.38	547,519	2,830,662	$19,343,461	$6.83	$2.55	37.3%	$1,036,821	$1,033,704.64
36	Dec-25	84,776	1,053,994	$9,866,875	$9.36	549,926	6,973,789	$48,174,678	$6.91	$2.45	35.5%	$2,585,923	$2,502,197.60
37	Jan-26	85,178	1,337,047	$12,580,960	$9.41	550,640	8,796,764	$61,460,395	$6.99	$2.42	34.7%	$3,239,410	$3,238,481.44
38	Feb-26	84,934	1,498,503	$14,434,369	$9.63	551,478	9,843,849	$68,781,918	$6.99	$2.65	37.9%	$3,963,882	$3,963,730.11
39	**AVERAGE Total (L)**	81,394	542,627	$4,971,614	$9.35	541,584	3,718,102	$23,989,394	$6.40	$2.94	46.0%	$56,699,610	$57,864,250

CAUSE-PA ST. 1
APPENDIX C, EXHIBIT C-6
CLI SHOPPING V. DEFAULT

UGI Utilities, Inc. - Gas Division
Confirmed Low Income Customers, Sales, and Commodity Supply Charges-Shopping and Default Service
January 2023 - January 2026

Source: Attachment CAUSE-PA 7-1

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
LINE#	Month	Total CLI Shopping Customers	Total billed usage of CLI shopping customers-Mcf's	Total billed commodity supply charges for CLI shopping customers - $	Average Cost per Mcf Shopping Customers	Total Residential default service customers	Total billed usage of Residential default service customers- Mcf's	Total billed commodity supply charges for Residential default service customers - $	Average Cost per Mcf Default Service Customers	Dollar Amount Difference in Average Cost per Mcf Shopping vs Default ($)	Percentage Difference in Average Cost per Mcf Shopping vs Default (%)	Difference in Aggregate Cost Shopping v. Default Column (J) times (C)	Difference in Aggregate Cost Shopping v. Default Service Price To Compare
1	Jan-23	4844	70689	$755,056	$10.68	43311	716500	$4,448,356	$6.21	$4.47	72.0%	$316,187	$110,690.42
2	Feb-23	4853	65551	$703,417	$10.73	43836	673835	$4,268,699	$6.33	$4.40	69.4%	$288,153	$105,883.21
3	Mar-23	4856	58141	$616,348	$10.60	44441	606195	$3,344,416	$5.52	$5.08	92.1%	$295,582	$165,141.28
4	Apr-23	4983	37408	$377,350	$10.09	45347	398749	$2,050,259	$5.14	$4.95	96.2%	$185,007	$87,039.92
5	May-23	5011	19680	$194,138	$9.86	45468	213071	$1,044,339	$4.90	$4.96	101.3%	$97,680	$41,411.72
6	Jun-23	5147	10199	$98,129	$9.62	45544	101636	$484,041	$4.76	$4.86	102.0%	$49,556	$18,977.86
7	Jul-23	5217	7895	$76,293	$9.66	45597	70494	$354,044	$5.02	$4.64	92.4%	$36,641	$15,022.29
8	Aug-23	5373	7143	$68,383	$9.57	45998	62155	$301,166	$4.85	$4.73	97.6%	$33,771	$12,947.48
9	Sep-23	5384	7866	$74,935	$9.53	46067	69114	$341,436	$4.94	$4.59	92.8%	$36,073	$13,887.02
10	Oct-23	5450	12882	$118,316	$9.18	46839	125327	$575,042	$4.59	$4.60	100.2%	$59,212	$18,347.83
11	Nov-23	5567	33305	$302,394	$9.08	47820	332893	$1,544,475	$4.64	$4.44	95.7%	$147,872	$43,924.11
12	Dec-23	5615	66351	$601,974	$9.07	48540	652212	$2,480,620	$3.80	$5.27	138.5%	$349,616	$301,173.10
13	Jan-24	5740	81952	$752,390	$9.18	49142	787383	$2,160,607	$2.74	$6.44	234.6%	$527,510	$380,859.25
14	Feb-24	5775	79595	$735,383	$9.24	49725	784562	$2,219,948	$2.83	$6.41	226.5%	$510,166	$374,538.61
15	Mar-24	5819	63405	$573,179	$9.04	50312	630374	$1,666,695	$2.64	$6.40	241.9%	$405,537	$310,878.44
16	Apr-24	5926	48149	$425,395	$8.84	51276	493949	$1,202,019	$2.43	$6.40	263.1%	$308,226	$226,208.64
17	May-24	6006	20416	$182,637	$8.95	51468	208582	$498,124	$2.39	$6.56	274.6%	$133,880	$98,177.22
18	Jun-24	6014	10779	$96,670	$8.97	51496	99906	$258,417	$2.59	$6.38	246.7%	$68,789	$46,066.91
19	Jul-24	6065	8177	$75,908	$9.28	52060	72271	$205,852	$2.85	$6.44	225.9%	$52,618	$37,522.60
20	Aug-24	6140	7799	$70,741	$9.07	51941	68166	$194,865	$2.86	$6.21	217.3%	$48,445	$34,125.94
21	Sep-24	6071	8904	$69,390	$7.79	52369	80092	$198,715	$2.48	$5.31	214.1%	$47,298	$27,588.34
22	Oct-24	6242	13444	$115,641	$8.60	53075	128104	$332,134	$2.59	$6.01	231.8%	$80,785	$52,526.33
23	Nov-24	6344	29839	$261,058	$8.75	54376	303656	$861,310	$2.84	$5.91	208.4%	$176,420	$120,974.89
24	Dec-24	6348	78560	$664,952	$8.46	55405	774912	$2,309,599	$2.98	$5.48	184.0%	$430,808	$207,585.86
25	Jan-25	6510	113961	$1,005,755	$8.83	56094	1090255	$3,721,417	$3.41	$5.41	158.6%	$616,766	$342,284.87
26	Feb-25	6642	121675	$1,102,347	$9.06	56683	1149388	$4,165,422	$3.62	$5.44	150.0%	$661,394	$393,970.23
27	Mar-25	6688	86631	$837,961	$9.67	57402	841682	$3,231,224	$3.84	$5.83	152.0%	$505,384	$246,955.65
28	Apr-25	6831	51019	$492,580	$9.65	58609	509716	$2,077,738	$4.08	$5.58	136.9%	$284,614	$144,525.33
29	May-25	6887	23994	$245,315	$10.22	58573	237649	$1,000,036	$4.21	$6.02	143.0%	$144,346	$81,622.80
30	Jun-25	6939	15716	$155,877	$9.92	58784	153300	$629,147	$4.10	$5.81	141.7%	$91,378	$48,660.19
31	Jul-25	7009	10000	$100,319	$10.03	58950	86512	$339,876	$3.93	$6.10	155.4%	$61,034	$32,100.05
32	Aug-25	7009	9036	$91,487	$10.13	58450	76897	$307,833	$4.00	$6.12	152.9%	$55,316	$29,845.92
33	Sep-25	7091	10501	$107,090	$10.20	59001	90618	$359,032	$3.96	$6.24	157.4%	$65,485	$35,451.81
34	Oct-25	7082	14901	$139,229	$9.34	59383	137086	$485,845	$3.54	$5.80	163.6%	$86,420	$37,575.62
35	Nov-25	7181	45342	$434,197	$9.58	60839	447961	$1,625,504	$3.63	$5.95	163.9%	$269,665	$124,002.63
36	Dec-25	7270	101865	$951,191	$9.34	61704	967599	$3,490,961	$3.61	$5.73	158.8%	$583,678	$239,422.29
37	Jan-26	7324	131380	$1,278,614	$9.73	60965	1215506	$4,618,650	$3.80	$5.93	156.1%	$779,400	$360,611.48
39	**AVERAGE**	6,088	42,815	$404,109.16	$9.45	52,348	417,792	$1,605,348	$3.86	$5.59	145.0%	$8,890,713	$4,968,528.17

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523, et al.
	:	
UGI Utilities, Inc. - Gas Division	:	

SURREBUTTAL TESTIMONY OF PATRICK M. CICERO
ON BEHALF OF
THE COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

May 27, 2026

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Appendix A:

Exhibit Cicero 1-SR: Shapiro Letter

Exhibit Cicero 2-SR: Income $50k-$100k within UGI Service Territory

Exhibit Cicero 3-SR: CLI Arrears vs. Operation Share Budget

PREPARED SURREBUTTAL TESTIMONY OF PATRICK M. CICERO

I. Introduction and Background

Q: Please state your name, occupation, and business address?

A: My name is Patrick M. Cicero. In my role as Of Counsel at the Pennsylvania Utility Law Project (PULP), I have a broad range of responsibilities to PULP and its clients. This includes providing analysis and testimony on utility matters for clients who are represented by members of the statewide legal aid network, including clients of PULP and other legal aid offices. PULP's business address is 118 Locust Street, Harrisburg, PA 17101. I also maintain an office at my home.

Q: Did you previously submit testimony in this proceeding?

A: Yes. On April 13, 2026, I submitted direct testimony that will be marked as CAUSE-PA Statement 1 on behalf of the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA). On April 27, 2026, I submitted errata to my direct testimony correcting a typographical error.

Q: What is the purpose of your surrebuttal testimony?

A: My surrebuttal testimony responds to the rebuttal testimony submitted by UGI witnesses Jessica R. Rogers,[1] Cyndee S. Fang,[2] Brian J. Meilinger,[3] John D. Taylor,[4] Dylan W. D'Ascendis,[5] Daniel V. Adamo,[6] and Jill E. Walter.[7] In addition, I will be responding to OSBA witness Mark D. Ewen.[8] My surrebuttal does not address every issue

[1] UGI Statement No. 15-R.
[2] UGI Statement No. 16-R.
[3] UGI Statement No. 12-R.
[4] UGI Statement No. 11-R.
[5] UGI Statement No. 8-R.
[6] UGI Statement No. 13-R.
[7] UGI Statement No. 3-R.
[8] OSBA Statement No. 1-R.

raised or discussed by these witnesses or other witnesses. The absence of any response by me to any issue raised by UGI or other parties in rebuttal does not indicate that I agree with those parties or their positions. Also, unless necessary for framing a response to the issues raised by UGI and OSBA in rebuttal, I will not repeat the extensive positions that I took in direct testimony. To the extent that an argument raised by any party in rebuttal was already sufficiently addressed in direct, I do not intend to respond to it here. I have not modified the positions that I have taken in this proceeding and stand firmly behind my positions, opinions, evaluation, analysis, and recommendations made in my direct testimony.

Q: How is your surrebuttal organized?

A: My surrebuttal responds to the witnesses topically. In part II, I respond to some general issues raised by UGI witnesses Rogers and Fang regarding affordability and the scope of utility responsibility for addressing unaffordable utility bills. I also discuss the overall revenue requirement and respond to UGI witness D'Ascendis in this section. In part III, I respond to UGI witness Rogers on the regulatory compact and principles of ratemaking. In part IV, I respond to UGI witness Meilinger regarding UGI's continued refusal to take reasonable measures to screen customers to ensure that they are informed of available assistance programs, and his response to my testimony on low income programs. In part V, I address UGI witness Taylor and UGI's proposed increase to the residential customer charge as well as its request to continue its WNA. In part VI, I address UGI witness Adamo's rebuttal testimony to my recommended tariff changes and to UGI witness Walter's testimony regarding termination procedures. In Part VII, I address

OSBA witness Ewen concerning recovery of universal service costs. Finally, in Part VII, I respond to Ms. Rogers testimony regarding UGI's Purchase of Receivables program.

II. General Affordability Concerns

Q: Please summarize this section of your testimony and the rebuttal of witnesses Rogers and Fang to which you are responding?

A: Both witnesses advance a common theme: that my testimony improperly attempts to convert a cost-of-service rate case into a vehicle for addressing broad macroeconomic conditions or general social welfare objectives. That characterization is inaccurate and should be rejected. My direct testimony is grounded in UGI's own data and discovery responses. It presents a company-specific case that UGI does not need the rate increase it is requesting because it is already earning sufficient returns, and that any increase would create devasting economic impacts for low income customers and their continued ability to afford to remain connected to UGI's service.

Q: Ms. Rogers characterizes your testimony as advancing a proposal that would "supplant" the Commission's detailed analytic process in favor of a "generic rejection" based on macroeconomic conditions,[9] and Ms. Fang similarly argues that CAUSE-PA seeks to use utility ratemaking as a substitute for general social welfare policy.[10] Are these accurate characterizations of your position?

A: No. Both witnesses oversimplify my analysis. My testimony does not argue that rates should be suppressed simply because inflation is high or because household budgets are broadly strained. I have not argued that the Commission should abandon

[9] UGI Statement No. 15-R at 7:8-11
[10] UGI Statement No. 16-R at 5-7.

cost-of-service analysis or disallow any specific cost item based on macroeconomic conditions. In fact, I have not challenged the specific expense or capital investments that UGI seeks to make in its Fully Projected Future Test Year (FPFTY). What I have argued – and what the Commission is empowered and obligated to do – is to exercise the full scope of its statutory discretion in determining just and reasonable rates, which includes consideration of the demonstrated impact of those rates on consumers.

Ms. Rogers and Ms. Fang would have the Commission perform only half of the ratemaking balancing test – the half that benefits UGI – but ignores the consumer side of that balance entirely. The Commission is not only authorized but required to take the impact of rates on consumers into account to ensure that universal service programs are adequate and that low-income customers can maintain access to service on reasonable terms.[11]

Q: Witness Rogers asserts that your testimony would replace the Commission's "prudency standard with an ever-shifting macroeconomic veto."[12] Do you agree?

A: No. I have not proposed that the Commission evaluate rate relief based solely on external economic conditions, nor have I proposed that Commission ignore or disregard prudently incurred costs. The evidence in this case suggests that UGI is well capitalized, has sufficient revenue, and does not need this increase. UGI disagrees – not because it would be unable to meet its projected capital expenditures, continue to provide safe and reliable service, or replace at risk pipe without the increase, but merely because it would earn less money doing so. This case is all about the level of profit that the Commission

[11] 66 Pa. C.S. § 2203
[12] UGI Statement No. 15-R at 18:20-21.

should allow UGI to earn. What I have argued is that the Commission should consider the totality of evidence – including UGI's robust financial health and the demonstrated inability of ratepayers to absorb further increases – in determining whether, and to what extent, a rate increase is warranted. Ms. Rogers herself acknowledges that the Commission should consider affordability in this proceeding, yet she then argues that all evidence of affordability and hardship should be disregarded if it does not fit neatly within the narrow ratemaking cost-of-service categories that she outlines.[13]

Q. Please explain what you mean when you say that Ms. Rogers argues that cost-of-service ratemaking is the lens through which affordability principles should be applied.

A: Ms. Rogers wants to put the Commission in a box and require it only to address affordability "as a part of cost of [UGI's] service" and cites rate design and other vague "policies and practices" to support her view.[14] This view of cost-of-service ratemaking is too narrow because it turns ratemaking into a simple math exercise – disregarding any consideration of UGI's customer base, or their ability to reasonably afford basic, life-sustaining services to their home. To be sure, the Commission must base its decision on facts – but it is not limited to considering only those facts presented by the utility. UGI seeks to divorce its needs from the needs of its customers. However, the Commission has a responsibility to ensure that rates are affordable, that service is accessible to those in need, and that UGI is not taking undue and unfair advantage of its customers. I am not arguing that the Commission should substitute macroeconomic analysis for cost-of-service ratemaking. I am arguing that the Commission must look at underlying economic

[13] UGI Statement No. 15-R at 21-22.
[14] Id. at 22:3-15.

fundamentals of both UGI and its customers to determine the appropriate authorized rates in this case. This is fundamentally consistent with cost of service ratemaking as it reaffirmed in its FPFTY Final Form Rulemaking Order, which concluded that the Commission oversight "serves as a proxy for a competitive market in appropriately restraining, or exerting downward pressure on, the profit-maximizing prices a monopoly could otherwise charge."[15] Exercising that restraint in light of the specific, company-level financial evidence I presented in direct testimony, and that has been presented by other witnesses in this case, is precisely what the Commission's statutory mandate requires.

Q: Ms. Rogers points to UGI's affordability-related activities – including donations to Operation Share and contributions to low-income programs – as evidence that UGI has "thoughtfully approached" affordability. How do you respond?

A: These activities, while necessary, do not offset the demonstrated and quantified harm to low income customers from UGI's proposed rate increase that I have outlined in my direct testimony. The facts of the matter are:

- UGI reports that the average income of UGI's confirmed low income customers is approximately $20,000.[16]
- Energy burdens for these households are 12%-15% during the winter heating months at existing rates and would increase to 13%-16% during these months at proposed rates.[17]
- 82% of UGI's low income customers are not enrolled in its customer assistance program (CAP) and are charged the full tariff rate along with any approved increase.[18]

[15] Use of Fully Projected Future Test Year 52 Pa. Code Chapter 53, PUC Docket No. L-2012-2317273, Final Form Order at 4 (order entered January 8, 2025), available at: https://www.puc.pa.gov/pcdocs/1874340.pdf
[16] CAUSE-PA Statement No. 1 at 20.
[17] Id. at 26, Table 3.
[18] Id. at 69:8-12.

- UGI's low income customers carry a disproportionate amount of customer debt and are far more likely to have their service involuntarily terminated for nonpayment than residential customers as a whole.[19] In fact, confirmed low income customers who are not enrolled in CAP have a utility termination rate that is 400%-500% higher than all residential customers and 500%-850% higher than residential customers who are not low income.[20]

Charitable donations alone will not address these issues. They are discretionary, not guaranteed, and are not calibrated to address the harm caused by this specific rate increase. Charity cannot substitute for the Commission's mandate to ensure that rates are just and reasonable for all customers. This is why it is important for the Commission to focus on UGI's authorized return on equity – it is an area about which the Commission has significant discretion, and it impacts the affordability of rates considerably.

Q: What does Ms. Roger's say about your analysis about UGI's profits, net income, and rate of return?

A: Ms. Roger's testimony is a plea for the Commission to look straight-ahead, put-on blinders, and examine only the evidence and issues that UGI puts in front of it without examining or contextualizing UGI's recent and current financial position or the needs of its customers. Ms. Roger's asserts that "[T]his case is driven by capital investments."[21] To a certain extent I would agree – it is driven by UGI's desire to invest its capital at an administratively determined equity return of 10.75% as opposed to investing its capital at its current equity return – which as of 5 months ago was 10.43% and which even in its worst possible projections at current authorized revenues will be 7.7% in September 2027.[22] As noted, I have not challenged UGI's capital or operating expenses in this case

[19] CAUSE-PA Statement No. 1 at 27.
[20] Id. at 28.
[21] UGI Statement No. 15-R at 8:3.
[22] CAUSE-PA Statement No. 1 at 38-40; UGI Statement No. 1 at 6:18-21.

and to the best of my knowledge no other party has challenged UGI's capital investment projections. The parties have either agreed with or simply not challenged those investments, but rather they have challenged whether UGI needs additional revenue above and beyond that which it is currently authorized to collect to make these investments and earn a fair rate of return. From my view, this case is about whether UGI should earn 8.22 cents on every dollar of capital investment that it makes and places into rate base or 6.55 cents on every dollar, or something in between.[23] When expressed in cents per dollar invested, the difference between what UGI wants and what it currently collects can seem small, but as noted in my direct testimony, at the 305 basis points that UGI is asking for in this case to take its ROE from 7.70% to 10.75%, UGI is asking the Commission to require customers to pay an additional $91.5 million each year.[24] This means that 92% of the increase that has been sought by UGI is driven by its requested ROE and capital structure.

This case is not at all about whether UGI will have sufficient cash or net income to ensure that it can meet its legal obligations or ensure safe and reliable service to its customers. It is not about whether UGI should make the investments, or whether it should receive recovery for doing so. It is all about the adequacy of the return that UGI will derive from those investments, and whether and to what extent its customers can afford to foot the bill.

[23] This is the difference between an 8.2% rate of return requested by UGI in this case at 10.75% ROE at its requested capital structure versus what it projects that it would earn absent a rate increase – 6.55% at 7.7% ROE and its existing authorized capital structure.
[24] CAUSE-PA Statement No. 1 at 42-43.

Q: Ms. Rogers says that it is important for UGI to earn its requested rate of return because the "Company must be able to attract capital at a reasonable cost in order to undertake the investments necessary to provide safe and reliable service."[25] Do you agree with her on this point?

A: I agree that UGI needs to be able to attract capital, I disagree that 10.75% is the required return that is needed. As noted above, this case is about how much profit the Commission will allow UGI to embed in its rates, not whether the Company's capital planning or operating expenses will be able to be recovered. While Ms. Rogers says that the magnitude of its UGI's capital expenditure plan alone "clearly indicates that rate relief is necessary"[26], no party has challenged those planned investments and UGI will be able to recover them in rates. The only relevant question is what it will cost consumers and whether UGI needs additional annual revenue to do so. As noted in my direct testimony, UGI has had robust net income and earnings over the past many years and have never earned a return lower than 10.43% since 2023.[27] UGI projects net income of $236 million through September 2026 and anticipates returning another $60 million in dividends to its parent company.[28] It is clearly not capital starved.

[25] UGI Statement No. 15-R at 10:2-3.
[26] Id. at 10:20.
[27] CAUSE-PA Statement No. 1 at 38, Table 8.
[28] Id. at 39.

Q: Ms. Rogers[29] and Mr. D'Ascendis[30] both state that you have not conducted any analysis to demonstrate that 7.70% would be a reasonable rate of return in your recommendation that UGI not be awarded a rate increase. What is your response?

A: I have not conducted a rate of return analysis using either of the traditional cost of capital methods, but that is not material. I am not recommending that rates be set at an ROE of 7.70%. Instead, based on the record, the Commission should find that UGI did not meet its burden of demonstrating that absent rate relief it would not have a reasonable opportunity to earn a fair rate of return. This is based on the totality of the evidence presented, including UGI's projected revenue at existing rates, UGI's robust financial position and the financial position of its parent company both of which have access to debt and equity financing to support UGI, and the very real, concrete and defined affordability crisis facing UGI's low income customers. Simply put, UGI has not demonstrated that it needs a rate increase.

While UGI *projects* that in September of 2027 it will be earning 7.70%, that is a mere projection and, between now and then, it is likely to earn significantly more than that rate. What UGI actually earns without rate relief will depend on a lot of factors, including the rate design approved in this case, whether the Commission continues to allow it to recover its authorized revenue requirement through the WNA, its overall sales, and how well or poorly it manages the efficiency of its operations. UGI has a reasonable opportunity to earn a fair rate of return at existing rates, and without an increase it will have appropriate incentives to operate more efficiently to earn a fair return.

[29] UGI Statement No. 15-R at 13.
[30] UGI Statement No. 8-R at 64.

To the extent that either Ms. Rogers or Mr. D'Ascendis is arguing that there is a sacred methodology the Commission must use to determine a rate of return or rates in general, this is simply inconsistent with the developed case law. As counsel for CAUSE-PA will address more fully in briefing, there is no single ratemaking method that is constitutionally or statutorily required; what matters is the end result.[31] UGI has not demonstrated that, absent rate relief, the end result would be deprive it of a reasonable opportunity to earn a fair rate of return.

Q: Ms. Rogers criticizes your observations about UGI's net operating income, recent equity returns and profit stating that you erroneously overstated UGI's net income and that focusing on net income at the exclusion of "free cash" is an error. What is your response?

A: Ms. Rogers indicates that Table 7 in my testimony overstates UGI's net operating income because the month of September reflects the entire fiscal year rather than a single quarter.[32] The data I used in Table 7 was provided by UGI in discovery. However, even with this correction to UGI's presentation of the data, UGI earned over $1 billion in net income from March 2021 through December 2025 – while at the same time residential customers experienced record terminations and carried record debt.[33] Ms. Rogers notes that UGI only sent 21.4% ($214 million) of that net revenue back to its parents as dividends and reinvested the rest in the system,[34] and that it had negative "free cash flow"

[31] See FPC v Hope Natural Gas, 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. It is not the theory but the impact of the rate order which counts.")
[32] UGI Statement No. 15-R at 20.
[33] Id. at 21:1; UGI Gas Exhibit JRR-3R.
[34] UGI Statement No. 15 -R at 21:3-6. In my direct testimony, I show that UGI actually sent $249 million to its parent company as dividend payments from 2021-2025. CAUSE-PA Statement No. 1 at 36, Table 6.

for calendar years 2021 through 2025 of ($587 million).[35] Neither of these statements indicate anything of significance. Capital intensive utilities routinely have negative free cash flow because capital expenditures exceed operating cash flow. This is a function of the infrastructure investment business model, not a sign of financial distress. During this same period, UGI received equity contributions of $50 million, sent dividends of $249 million to its parent,[36] and issued debt. This is how utilities operate. They move money. Furthermore, despite this so called negative free cash flow, UGI admitted in discovery that "UGI's ability to attract capital needed to make investments that support operating a safe and reliable distribution system was not jeopardized during any quarter in the period from January 1, 2023 through December 31, 2025."[37] Nothing here indicates that UGI would not be able to do the same absent a further rate increase. It is critical to recall that UGI is a non-publicly traded utility whose sole owner exercises complete control over its capital structure and equity contributions. The Commission is entitled to scrutinize whether the level of dividends paid, combined with UGI's equity-heavy capital structure, represents a fair allocation of financial risk between shareholders and ratepayers. UGI may send less profit up to its corporate parent, but it will still have access to cash and there is no record evidence suggesting otherwise.

[35] UGI Statement No. 15-R at 21:10.
[36] See CAUSE-PA Statement No. 1 at 36, Table 6. Note that despite stating in her testimony that UGI sent $214 million to its parent from 2021 through 2025, Ms. Rogers did not dispute the $249 million figure that was in Table 6 of my testimony and which was derived from the Company's standard data requests made with their filing.
[37] CAUSE-PA Statement No. 1 at 38:7-10 (citing UGI Response to CAUSE-PA 3-1(b)).

Q: Ms. Fang argues that you misconstrue the scope of utility regulation, and that "[e]xpanding utility responsibility to address economywide affordability pressures would improperly transform ratemaking into a general social policy tool, contract to long-standing cost of service principles."[38] What is your response?

A: Ms. Fang is incorrect. Nowhere in my testimony did I suggest that UGI or any other utility is responsible for economywide affordability pressures. My direct testimony is rooted in addressing core attributes of whether UGI is already sufficiently capitalized at current rates with sufficient revenue to have a reasonable opportunity to earn a fair rate of return. However, Ms. Fang only wants to address UGI's side of the coin. A proper assessment requires consideration of whether rates are affordable, such that service will be universally accessible to customers in UGI's service territory. My testimony focused on both sides. Specifically, it focused on UGI's revenue request, capital structure, rate design and its obligation under Pennsylvania law to ensure that low income households can afford and maintain service. I submit that rates are not just and reasonable, and profits are unfair, if the result is to price low income families out of the market for basic gas services to their home. In my direct testimony, I did not seek to impose an obligation on UGI to resolve poverty. I pointed out the facts about UGI's customers to contextualize the hardships that they face to heat their home due to *UGI's choices in this case.* Those choices include:

- requesting a nearly $100 million rate increase a mere three months after its last rate increase went into effect;
- requesting a return of 10.75% a mere 30 days after it was earning 10.43% and returned $88 million in net income to itself and its corporate parent;

[38] UGI Statement No. 16-R at 5-6.

- requesting an equity skewed capital structure that unreasonably enriches UGI's shareholders at the expense of ratepayers; and,
- refusing to implement modest reforms to its screening and referral processes to ensure that more of its income eligible customers have an opportunity to enroll in programs for which they are eligible and UGI is legally required to offer.

Q: Ms. Fang also suggests that "Pennsylvania's affordability challenges are best advanced through a coordinated, statewide approach across essential utility services."[39] What is your response?

A: This is a common refrain from utilities who want to avoid accountability for their decisions and their role in having unaffordable rates and unfair rate design. The simple reality is that all the issues I presented are squarely within the responsibility of UGI as the monopoly provider of gas distribution service and all of this is properly before the Commission in this case. My testimony is consistent with the long standing framing by the Commission that it must consider the needs of consumers, including rate affordability, in setting the cost of equity and rate design.[40] The authority for the Commission to consider these issues in rate cases is well known and abundantly clear.[41] Of course, CAUSE-PA would be happy to engage in a statewide conversation about ways in which the Commission can restrain excessive ROEs and equity rich capital structures that favor utilities at the expense of consumers. Statewide reform of these issues would be a welcome achievement, as recently called for by Governor Shapiro in his April 29, 2026,

[39] UGI Statement No. 16-R at 6:20-21.
[40] See e.g., Pa. Pub. Util. Comm'n, et. al v. Twin Lakes Utilities, Inc., Docket No. R-2019-3010958, at 48, 80 (Order entered March 26, 2020) (finding that the ALJ did not err in considering evidence relating to the various quality of service and rate affordability issues in the proceeding and factoring in such evidence as part of her overall determination on which expert witnesses' cost of equity to adopt for setting just and reasonable rates).
[41] See e.g., Popowsky v. Pa. Pub. Util. Comm'n, 683 A.2d 958, 961 (Pa. Cmwlth. 1996) (stating that the Commission "has broad discretion in determining whether rates are reasonable" and "is vested with discretion to decide what factors it will consider in setting or evaluating a utility's rates").

letter to utility CEOs[42] and as recently introduced in HB 2224,[43] which would reform the process of establishing equity returns to make it fundamentally more consistent with the actual cost of equity. However, even this call for more fair rates by our political leaders at a systemic level does not alleviate the obligation of the Commission to address these concerns in the context of a specific utility's request in a specific utility rate case.

Q: Ms. Fang also states that the existing Commission-approved mechanisms to address affordability – such as Customer Assistance Programs (CAP) and other Universal Service Programs – currently exist and are the appropriate framework to address concerns about unaffordable bills.[44] Do you agree?

A: I certainly agree that for income-eligible households – that is, for households with income at or below 150% of the federal poverty level – the best way to materially and significantly improve affordability is through enrollment in CAP. Customers with income below 150% of FPL[45] simply have no ability to adequately maintain service on a continuous basis without the significant and ongoing assistance that CAP provides. This is precisely why I made the recommendations that I did in my direct testimony about additional screening to identify eligible households – recommendations that UGI stubbornly insists are unnecessary.[46] Despite UGI's consistent refusal to appropriately classify and identify confirmed low income households or advance more fulsome measures to improve enrollment in these necessary programs, I share Ms. Fang's

[42] Exhibit Cicero 1-SR, Letter from Governor Josh Shapiro to Utility CEOs dated April 29, 2026, attached hereto at Appendix A.
[43] HB 2224 ("Saving Taxpayers Money by Limiting Excessive Profits for Utility Monopolies"). Introduced May 20, 2026. Available at: https://www.palegis.us/legislation/bills/2025/hb2224,
[44] UGI Statement No. 16-R at 7.
[45] A family of 4 with income at or less than $49,500 per year has income at or below 150% of the FPL. The complete federal poverty guidelines are available at Federal Register, Vol. 91, No. 10 (January 15, 2026). Available at: https://www.govinfo.gov/content/pkg/FR-2026-01-15/pdf/2026-00755.pdf.
[46] UGI Statement No. 12-R at 15.

position that these programs are the best way to address affordability concerns for low income eligible households. However, more than 100,000 estimated eligible households are not enrolled.[47] Until or unless these households enroll in CAP, Ms. Fang's position that the Commission should not address core ratemaking principles that drive unaffordable bills is patently unreasonable.

Furthermore, as discussed in my direct testimony, there are a considerable number of households within UGI's service territory that reside at incomes below the economic self-sufficiency standard[48] but above the income level needed to qualify for CAP. For example, in 2023, the last year for which data is publicly available for all of the counties UGI serves, approximately 30.7% of all households had income *greater than* $50,000 annually but less than $100,000 annually.[49] This is approximately 195,000 of UGI's customers.[50] These households are not eligible for financial assistance through CAP or LIHEAP, but generally struggle to afford to pay for all necessities – including utility service.[51] Thus, these households must rely on the Commission to exercise its core

[47] CAUSE-PA Statement No. 1 at 69-75.
[48] See Id. at 20 for an explanation of the self-sufficiency standard. See also, Self-Sufficiency Standard, available at: http://www.selfsufficiencystandard.org/Pennsylvania. (Last visited March 31, 2026). The Self-Sufficiency Standard defines the income working families need to meet a minimum yet adequate standard of living, considering family composition, ages of children, and geographic differences in costs. The Standard is an affordability and living wage economic security measure that provides an alternative to the official poverty measure.
[49] See U.S. Census Bureau, U.S. Department of Commerce. "Income in the Past 12 Months (in 2023 Inflation-Adjusted Dollars)." American Community Survey, ACS 5-Year Estimates Subject Tables, Table S1901, https://data.census.gov/table/ACSST5Y2023.S1901?t=Income+and+Poverty&g=040XX00US42$0500000_050XX00US42117. (Accessed and last visited on May 19 2026.).
[50] See Exhibit Cicero 2-SR, attached hereto at Appendix A.
[51] See CAUSE-PA Statement No. 1 at 20. ("Based on the 2024 Self Sufficiency Standard, a family of four (consisting of 2 adults and 2 school-aged children) living in the counties served by UGI requires an income ranging from $69,077 to $104,762.").

function as the economic regulator of UGI and restrain its monopolistic tendency towards excessive rates.[52]

Q: Ms. Fang states in her testimony that the effect of denying UGI rate relief in this case would be to "suppress recovery of prudent costs" and erode UGI's ability to earn its authorized return.[53] What is your response?

A: I disagree. My position in this case is that UGI has not met its burden to prove that its current rates are insufficient to recover its reasonable and prudently incurred costs, now or into the future. Moreover, I submit that the record indicates that UGI can earn a fair rate of return with prudent management at existing rates. I did not challenge either UGI's operating or capital expenditures. Thus, any decision about whether to delay or avoid those expenses – what Ms. Fang calls suppressing – would be UGI's management decision to do so, presumably to allow it to make more money for its shareholders rather than investing it in the system. That Ms. Fang and UGI seek to blame intervenors for its hypothetical future management decisions amounts to nothing more than gaslighting.

Q: Ms. Fang asserts that you and Mr. Colton for the OCA do not provide an accurate assessment of current energy burdens of UGI's customers.[54] Do you agree?

A: No. Ms. Fang's general analysis tells us nothing about the customers who struggle to pay their bills, and her analysis of low income customers reaffirms all my conclusions from my direct testimony. According to Ms. Fang, Atrium Economics conducted a

[52] I note that UGI witness Meilinger questions the use of self-sufficiency standard income information in his rebuttal testimony. See UGI Statement No. 12-R at 8. This information is relevant because it shows that the 195,000 households with income above the FPL but below the self-sufficiency standard do not qualify for assistance and thus will be materially impacted by any rate increase awarded in this case.
[53] UGI Statement No. 16-R at 11.
[54] Id. at 15.

customer-level "gas burden" survey using a proxy income from census data by mapping customers "to the median income of the Census block group in which the customer reside."[55] Based on this analysis, she concluded that the median income for all 454,815 gas-only customers was $83,026, and the median energy burden for this group as 1.34%.[56] There are several problems with using median income for this purpose.

First, using Census block group median household income as a proxy for individual customer income assigns a higher income to many customers who live in areas with moderate median incomes, but who themselves have very low incomes. My direct testimony, by contrast, relies on UGI's own discovery responses regarding the actual average annual income of its confirmed low-income customers ($20,146) and CAP customers ($17,208).[57]

Second, Atrium's analysis of the median gas burden across all 454,815 customers obscures the situation of the most vulnerable households. Finding that the median gas burden is 1.34% across all customers tells us almost nothing about whether low income customers can afford service. The relevant question – and the one I addressed in my direct testimony – is what confirmed low-income customers not enrolled in CAP spend on gas service as a percentage of their monthly income. The answer from the record is that, during winter months, these customers spend between 12% and 16% of their monthly income on gas alone.[58] This far exceeds the Commission's own 4% and 6% affordability thresholds for natural gas heating.[59]

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[55] UGI Statement No. 16-R at 16.
[56] Id.
[57] CAUSE-PA Statement 1 at 19-20.
[58] Id. at 25-26, Table 2 and 3.
[59] 52 Pa. Code §§ 69.261-69.267

Moreover, Atrium's own analysis of CAP-enrolled customers confirms the severity of the problem. Ms. Fang models the impact that CAP has on reducing energy burdens and compares CAP customers with CAP benefits and what those customers would have paid without CAP benefits.[60] Specifically, she modeled the impact at current rates for CAP customers with income greater than $0 and with 12 months of usage.[61] Consistent with my testimony, Ms. Fang found that "CAP benefits materially reduce gas burdens".[62] Specifically she found that CAP reduces the average gas burden from 13.02% without CAP benefits to 5.85% with CAP benefits.[63] The best and most effective way to ensure rate affordability for CAP-eligible households is to enroll them in CAP. Ms. Fang agrees, but then appears to assert that any improvements to CAP and other universal service programs should occur outside of "base ratemaking"[64] and that my concerns about program enrollment are more "appropriately addressed through universal service program review, rather than through base rate determinations focused on recovery of prudent costs necessary to provide safe and reliable service."[65] This is perplexing.

Ms. Fang's argument that affordability concerns – including addressing the significant enrollment concerns presented in my direct – should be addressed exclusively through universal service proceedings, and never through base rate outcomes, misunderstands how these two mechanisms interact. Base rate levels directly determine the size of the affordability problem. The higher UGI's rates, the more customers fall into energy insecurity, the higher CAP credits must be to restore affordability, and the higher

[60] UGI Statement No. 16-R at 18.
[61] Id. at 19.
[62] Id. at 23, Table 2
[63] Id.
[64] Id. at 26.
[65] Id. at 28:11-13.

the costs that all residential ratepayers must bear to pay for these programs. There is no meaningful separation between rate case issues and universal service issues. Base rates and universal service rider costs are both rates that must be addressed in this proceeding along with mitigation measures. Statutory law and Commission decisions support this policy position and will be addressed by counsel for CAUSE-PA through briefing [66]

The record in this rate case directly demonstrates the inadequacy of current universal service programs: 82% of UGI's estimated low-income customers are not enrolled in CAP;[67] confirmed low-income terminations increased 33% between 2023 and 2025 even as terminations declined for all other customer groups;[68] and in 2025, low-income customers not enrolled in CAP accounted for 36.4% of all residential gas shut-offs despite representing only 7% of customers.[69] The Commission and UGI cannot close their eyes to these facts simply because Ms. Fang prefers they be addressed in a different docket.

Q: Ms. Fang further argues that CAP enrollment gaps reflect programmatic concerns better suited to a universal service proceeding.[70] How do you respond?

A: Ms. Fang's position would leave UGI's most vulnerable customers without any protection in this proceeding. As noted above, the Commission has recognized that the adequacy of universal service programs is a factor in evaluating rate cases – that is precisely why parties routinely submit testimony on CAP and LIURP performance in base

[66] Pa. PUC v. PGW, Order, Docket No. R-2023-3037933 at 215-216 (Order dated Nov. 9, 2023) (finding that that deferring universal service issues to another forum would unreasonably "thwart the purpose of universal service, which is to help low-income customers maintain their natural gas services. See, 66 Pa. C.S. § 8 2202").
[67] CAUSE-PA Statement No. 1 at 16.
[68] Id. at 29, Chart 1.
[69] Id at 29-30.
[70] UGI Statement No. 16 at 28-29.

rate proceedings. Atrium's own data shows that CAP benefits reduce the average gas burden, but that reduction is not applicable to the more than 100,000 estimated low-income customers who are not enrolled. Their bills increase by the full amount of any rate increase authorized in this proceeding.

Finally, as I address more fully in my response to UGI witness Meilinger, below, my recommendations to require routine income screening at the time of account establishment, on non-emergency service calls, and through UGI's online portal are straightforward measures the Commission can and should require in this proceeding not deferred to the future.

III. Regulatory Compact and Principles of Ratemaking

Q: Ms. Rogers asserts that your analysis of the compounding impacts of the FPFTY, DSIC, and Weather Normalization Adjustment on consumers is incorrect, and that these mechanisms serve legitimate public purposes.[71] Do you maintain your position?

A: Yes. My concern – which Ms. Rogers does not address – is the cumulative effect of these mechanisms on the risk allocation between the utility and its captive ratepayers. Each mechanism individually shifts risk, but taken together, they substantially reduce UGI's business risk and shift that risk to customers who have no choice of service provider. The Commission, as a proxy for competition in this monopoly environment, must account for this reduced risk in authorizing an appropriate rate of return. UGI fails to recognize this in its requested return.

[71] UGI Statement No. 15 at 27-29

Q: Ms. Rogers claims that UGI has not asserted regulatory lag as a basis for its rate relief request. Does this undercut your testimony?

A: No. Whether UGI uses the words "regulatory lag" is beside the point. The FPFTY, by design, allows UGI to set rates based on projected future costs rather than current costs, thereby minimizing the timing mismatch that constitutes regulatory lag. This is a structural benefit that accrues financially to benefit UGI. The DSIC allows UGI to recover capital expenditures that are incurred above and beyond base rates as of the end of the FPFTY. Both reduce regulatory lag. The Commission should not ignore this benefit in setting the authorized return. For its part, the WNA allows UGI to collect revenue based on normalized as opposed to actual weather, thus it reduces a mismatch in setting rates and collecting rates that also has the same effect as reducing regulatory lag. That is, the result of the WNA is that UGI is able to collect more money in rates that it would otherwise have to forgo absent the WNA.

The regulation of public utilities by the Commission is meant to ensure the provision of a public good – gas distribution service – under terms and conditions that allow UGI the ability to recover its known and prudent costs and provides an opportunity to earn a fair and reasonable return *while at the same time* protecting the public from excessive rates and unfair rate design. My direct testimony focused on the needs of the public – particularly low income consumers who are the most vulnerable and most in need of the Commission's regulatory scrutiny of UGI's rates and rate design. My testimony seeks to have the Commission allocate the risk in ways that are fair and equitable based on the relative ability to manage that risk. UGI and its more than $1 billion in net revenue is far better able to manage the risk – especially with its alternative ratemaking

mechanisms – than UGI's low income customers whose average household income is less than $20,000 per year.[72]

IV. Low Income Program Issues

Q: UGI witness Brian Meilinger disagrees with your conclusion, and that of OCA witness Roger Colton, that UGI Gas bills are consistently unaffordable for low income customers.[73] Does he cite any evidence to support this conclusion?

A: No. In fact, he indicates that he does not dispute the income data cited, but instead indicates that that UGI's programs to assist low income customers function well.[74] He then proceeds to spend several pages of his testimony describing the various offerings that UGI has to assist low income households (those with income ≤ 150% FPL) and other economically vulnerable households (up to 200% FPL).[75] None of this is responsive to either my testimony or Mr. Colton's testimony. I do not dispute that UGI has an array of programs that assist low income households and did not make recommendations in my testimony about the structure, scope or design of those programs. UGI's universal service programs provide meaningful assistance to low income households *who are enrolled in those programs*, but they do nothing for households who are not. In my direct testimony, I provided evidence that low income customers who are not enrolled in CAP face devastating consequences that are exacerbated by UGI's frequent rate increases. For example, as shown on Chart 1 in my direct testimony,[76] terminations for UGI's poorest customers *increased* by 33% during the last three-year period – and for those not enrolled

[72] CAUSE-PA Statement No. 1 at 20.
[73] UGI Statement No. 12-R at 2.
[74] Id. at 2-3.
[75] Id.
[76] CAUSE-PA Statement No. 1 at 29, Chart 1.

in CAP the increase was 27% – even though terminations for all other groups decreased during this period.

The financial burden of rates and risk of termination are becoming increasingly concentrated within the UGI's low income customers who are not receiving program assistance.[77] Unfortunately, most customers for whom UGI has information that would reasonably place that customers in a low income category (i.e., their confirmed low income customers) are not enrolled in these programs and thus face the full impact of UGI's proposed rate hike. This is why I focused on clear and tangible ways for UGI to improve its CAP enrollment. As stated in my direct testimony: "there is a growing need for more targeted and strategic outreach to these high-risk customers to ensure that they have every opportunity to enroll in CAP before they experience service loss. Enrollment in CAP is the most significant, preventative thing that UGI can do to reduce the rate of service loss for low income customers, but the ability of UGI's CAP to mitigate unaffordability is immaterial if families are not enrolled."[78]

Q: Mr. Meilinger says that UGI "has demonstrated a concerted focus on continued marketing of CAP" and that he does not believe that anything else needs to be done to increase access to these programs. Do you agree with Mr. Meilinger?

A: No, I do not. Despite the evidence presented that CAP enrollment materially improves affordability and outcomes for customers – including by UGI witness Fang – Mr. Meilinger indefensibly "takes issue with [my] assessment that CAP enrollment numbers are not sufficient and more needs to be done."[79] Mr. Meilinger's position appears to be

[77] CAUSE-PA Statement No. 1 at 29, Chart 1.
[78] Id. at 30:5-10.
[79] UGI Statement No. 12-R at 13:9-10.

that UGI has programs and that it is simply up to people to come find the program. He blames low income customers themselves for not enrolling - asserting "that approximately 30,000 of the 40,000 confirmed low income customers are self-certified low income and have not made an effort to provide the Company or its Community Based Organizations ("CBOs") with documentation in order to income verify, enroll in CAP, and receive the associated program benefits."[80] This position is problematic and representative of a culture that blames poor people for the decisions that UGI has made that result in unaffordable rates and make it difficult for eligible households to access available programs. It also ignores the fact that UGI refuses to conduct a CAP intake at the time it learns information about a household's income, and instead it simply makes a referral to a CBO.[81] While referrals are an important part of the process, low income households have severe constraints on their time and resources – especially during business hours. UGI must have simple processes in place to verify income eligibility at the time UGI learns that a household is likely eligible for assistance.

Q: Mr. Meilinger also asserts that UGI's current screening and enrollment process is sufficient, and that it conducted a poll of participants and their willingness to share income information. What does he conclude?

A: In my direct testimony, I made a simple recommendation that UGI screen customers to inform them of available assistance.[82] Mr. Meilinger rejected this recommendation because he concludes that most customers will not want to share their income information and that the average handle time for calls may increase as customers

[80] UGI Statement No. 12-R at 12:15-18.
[81] Id. at 16.
[82] CAUSE-PA Statement No. 1 at 73.

ask questions about why they are being solicited to provide their income.[83] In addition, he provides information about the results of UGI's survey of its customers.

Q: Please describe UGI's survey.

A: UGI attempted to survey 4,736 of its customers, of which just 355 customers completed the survey.[84] UGI describes its survey as an effort to assesses customer's "willingness to provide their income to a call center representative."[85] The framing of the questions in the survey do not accurately correspond to my recommendations regarding low income screening on non-emergency calls. UGI's survey asked the respondents to answer the following question among others:

> In order to assist as many customers as possible who are eligible for income-based assistance programs, UGI Utilities is evaluating whether to ask all non-emergency callers for their household income. If UGI implemented this approach, how likely would you be to provide your household income over the phone?[86]

This is not the type of call screening that I recommended in my direct testimony, and it is understandable why customers would be hesitant to share their income information under these circumstances. What I recommended was that UGI simply inform callers that they may be eligible for lower rates and/or free energy efficiency measures and ask if they would like to provide income information, not that UGI collect income information from every single caller.[87] However, despite phrasing this question in a way designed to elicit a negative response, UGI's survey results actually bolster my screening recommendations. Of the 355 customers surveyed:

[83] UGI Statement No. 12-R at 15.
[84] Id.
[85] Id. at 15:15-17.
[86] UGI Response to CAUSE-PA 9-4, Attachment.
[87] CAUSE-PA Statement No. 1 at 73:1-17.

- 31% "probably would" or "definitely would" share their income with UGI. This number increases to 37% for those customers who call UGI 1-2 times per year and 33% for those customers who call UGI more than 3 times per year.[88]
- 22% are not sure if they would share their income, and just 47% - less than half – indicate that they "definitely wouldn't" or "probably wouldn't" share their income.[89]

Interestingly, several of the reasons given by the respondents show a fundamental misunderstanding of the survey question and flaws in the process. For instance, where customers were able to provide further context for why they selected "other" as the reason why they would not provide income information, UGI received the following responses:

- One respondent stated they were a landlord paying for the gas for 5 residential apartments. This customer should have been flagged as ineligible for the survey.
- One respondent was concerned they'd be charged a higher rate based on their income.
- One respondent stated, "Instead of asking for someone's household income, why not simply ask if they'd like to learn more about income-based assistance programs? I'd never provide my income if asked simply because I'd be concerned that it would be used for other purposes." This response reflects a preference for the type of screening that I recommended in my direct testimony and demonstrates why customers would respond negatively to the framing of the question posited by UGI.
- One customer stated, "I don[']t have a problem sharing my income just not over the phone."
- Another customer expressed interest in learning about assistance: "I would like information!!! I don't want my information displayed!!"
- One respondent stated, "If I was applying for assistance, I would expect UGI to need that info."
- One respondent stated, "Cost is ridiculously high, regardless of income level"[90]

[88] UGI Gas Exhibit BJM-10R at 3 of 5.
[89] Id.
[90] All responses quoted from UGI Response to CAUSE-PA 9-4, Attachment, Column L (Other – Please Specify).

Based on UGI's survey, Mr. Meilinger concludes that there would be a "low adoption, potential customer dissatisfaction, and associated expenses" that do "not seem justified given th[e] survey results."[91] Mr. Meilinger fails to mention in his testimony that 72% of customers surveyed where either "very interested" (26%), "somewhat interested" (34%), or "not sure" if they were interested (12%) in learning more about income-based assistance programs.[92]

Q: Do you agree with Mr. Meilinger's conclusion about what the survey results demonstrate?

A: No. UGI and its survey miss the point. I am <u>not</u> recommending that UGI ask every customer who calls its call center for a non-emergency call to provide their income information. I never made that recommendation. Instead, I am requesting UGI provide the following statement (or something similar) on all calls for customers who call their call center for non-emergency calls and for new and moving customers: *UGI offers reduced rates and other assistance for income qualified customers. Would you like to provide your household income information to see if you qualify?* If the customer says that they would like to find out more about whether they qualify, then UGI would provide additional information about these programs. If the customer says no, then the inquiry ends there. This does not seem onerous and would honor the desire of the 60% of customers who UGI surveyed who indicated that they were interested in learning more about UGI's income based assistance programs.

[91] UGI Statement No. 12-R at 15:18-20.
[92] UGI Gas Exhibit BJM 10R at 5 of 5.

Q: Do you agree with Mr. Meilinger that this would be expensive to implement or lead to customer frustration or confusion?

A: It is difficult to imagine that this is the case and UGI has provided no information about what the cost to implement this additional question would be, how it would affect call times, or why it would confuse or frustrate customers.

Q: Based on the information provided by Mr. Meilinger have you changed your position or recommendation?

A: No.

Q: What was your recommendation in direct about the information that UGI has from its use of Experian data concerning its customers?

A: My recommendation was that UGI update its confirmed low income customer count to include the households for which it has actual demographic data indicating that these households are low income. This includes the information that it has about customers based on the data it received from Experian about which UGI states that there is a 90% match rate on name and address.[93] Including these customers as confirmed low income customer count is appropriate because it is "information that would reasonably place the customer in a low-income designation" which is the requirement of the Commission's regulations at 52 Pa. Code § 62.2.

Q: What is Mr. Meilinger's response?

A: Mr. Meilinger makes several contentions that are non-responsive to my recommendation and honestly quite bizarre. For example, he says my recommendation is inappropriate because it would "take data from a third party vendor and override records

[93] CAUSE-PA Statement No. 1 at 23.

in [UGI's] Customer Information System."[94] I agree the scenario invented by Mr. Meilinger would be inappropriate, but I did not suggest that this is what should occur. In addition, Mr. Meilinger states that "it is unclear whether Witness Cicero is proposing that [a] customer who has self-certified and is included in the Company's confirmed low income customer counts but is not identified in Experian's data as low income, should be removed from the Company's records as a confirmed low income customer."[95] There is nothing unclear about my testimony and I made no such suggestion. If UGI has information in its customer information system that would reasonably place a customer in a low income designation, then that customer should be counted as confirmed low income. If a UGI customer has self-certified as low income, then that customer should be counted as confirmed low income. If UGI has information from a third party – including Experian – that reasonably places a customer in a low income designation, then that customer should be counted as confirmed low income. All of this is additive and consistent with the Commission's definition of "confirmed low-income customer."[96] UGI may have more than one source of information about a customer (i.e., they self-certify, they receive LIHEAP, and they show up in UGI's Experian data) the fact that there is more than one designator does not negate anything, it only reaffirms that the customer is confirmed low income. Thus, I stand by my recommendation that UGI should update its confirmed low income customer count to include all customers for whom it has information that would reasonably place the customer in a low income designation, including customers for whom the source of information is Experian data.

[94] UGI Statement No. 12-R at 10:17-23.
[95] Id.
[96] 52 Pa. Code § 62.2.

Q: Mr. Meilinger responds to your recommendation that UGI not reduce its Operation HELP donation by $84,500, and that the donation should be increased to account for any increase in rates approved in this case.[97] He claims your analysis is "limited" because you have not spoken to any Community Based Organizations (CBOs) about whether these organizations believe that this funding would be utilized.[98] What is your response to this position?

A: It is not clear why Mr. Meilinger believes that I should have consulted with CBOs, as there is abundant evidence of the need. As shown in Table 3, below, the difference between the average monthly arrears for 2024 and 2025 of UGI's confirmed low income customers and the total amount of hardship funding awarded *for the entire year* in 2024 and 2025 is staggering.

Table 3: Average Monthly CLI Arrears vs. Total Annual Hardship Funds Awarded[99]

	Average Monthly Confirmed Low Income Customer Arrears	Total Annual Operation Share Grants Awarded
2024	**$23,696,460**	**$668,305**
2025	**$30,138,452**	**$1,390,608**

The need for more grant assistance is self-evident even without a rate increase and there is no need to "confirm" whether the assistance is needed or should be made available. I reaffirm my position stated in my direct testimony: UGI should commit no less than its current grant amount of $1,584,500 annually, and if any rate increase is approved in this proceeding, it would be appropriate for UGI to contribute additional funds over and above

[97] UGI Statement No. 12-R at 17:22-18:5.
[98] Id.
[99] See Exhibit Cicero 3-SR, attached hereto at Appendix A.

this $1.5 million to account for the additional hardships caused by the impact of such an increase.

V. Rate Design

A. Customer Charge

Q: What was your position in your Direct Testimony regarding UGI's proposal to increase its fixed customer charge from $16.25 to $23 per month?

A: My position was that the proposed increase of the customer charge by $81 per year weakens the ability of low income households to save money on their bills each month because less of their bill is dependent on the volume of gas they consume.[100] I argued that the increase could weaken the effectiveness of weatherization measures from the Low Income Usage Reduction Program (LIURP) and the Weatherization Assistance Program (WAP) which would be contrary to the policy goals of these programs to reduce bills for customers through usage reduction.[101] I disagreed with UGI that bill stability without bill affordability is a benefit for low income households and that budget billing would be a better option for customer bill stability than an increase in the fixed charge.[102] Ultimately, I concluded that the fixed customer charge should not be increased because I was not recommending any increase in rates and was recommending that the WNA be discontinued. However, if the Commission were to conclude that the WNA was to continue, I did not oppose an increase in the fixed customer charge that would be proportionally scaled back to any authorized revenue increase awarded.[103]

[100] CAUSE-PA Statement No. 1 at 50.
[101] Id. at 52-52.
[102] Id. at 53-54.
[103] Id. at 54.

Q: What was Mr. Taylor's response?

A: Mr. Taylor asserts that concerns about energy efficiency and conservation should not trump rate design where the customer charge is intended to recover UGI's fixed costs that do not vary with usage.[104] Mr. Taylor also posits an academic theory of conservation that "should be understood as the wise and efficient use of utility resources – not merely the reduction of energy consumption.[105] Mr. Taylor asserts that low income households benefit from an increased in the fixed customer charge because they have less discretionary usage and it would help moderate seasonal bill volatility for these customers.[106] He argues that recovering more fixed costs in volumetric charges is regressive and increases the burden on some vulnerable households during the coldest months.[107]

Q: What is your response to Mr. Taylor's arguments?

A. Mr. Taylor posits a model of conservation that is rooted in economic theory but disconnected from lived reality. I disagree with his assertion that the Commission should narrow its examination of efficiency and conservation in a distribution rate case to focus only on the efficient use of utility distribution resources without consideration of the impact of distribution rate design on energy usage. Mr. Taylor's supposition ignores the critical need for energy conservation to advance a multitude of issues – from cost to resource adequacy – and occurs at the expense of customers' ability to reduce their distribution bills through conservation. I agree that the efficient use of the distribution system is a consideration in rate design, but my point, from the perspective of consumers, is that at

[104] UGI Statement No. 11-R at 20.
[105] Id. at 21.
[106] Id. at 26.
[107] Id. at 27.

current rates and at current rate design, low income customers have extraordinary difficulty being able to afford service and remain connected. This difficulty should not be compounded by increasing the fixed customer charge. Nothing in Mr. Taylor's testimony rebuts the notion that the ability of consumers to save money on their distribution bills through energy efficiency investment or conservation is reliant on a bill structure that bases the recovery of costs on volumetric throughput.

It is true that low income households are less able to afford home energy efficiency and weatherization – thus the need for increased LIURP enrollment and coordination. However, the reality is that they can ill afford to have more of their bill fixed without the ability to mitigate higher bills through conservation or energy efficiency, regardless of whether that means going without or adopting efficiency in their home. Wresting control from consumers to reduce their distribution bills through conservation and efficiency will only compound the already impossible choices facing low income families to forego other necessities to maintain life essential energy services to their home.

Regarding Mr. Taylor's arguments about bill stability, I agree that bill stability is a legitimate goal, but I disagree that increasing the fixed customer charge is the appropriate mechanism to achieve it for low-income customers. A bill that is stable but unaffordable provides no real benefit. Mr. Taylor acknowledges that many vulnerable customers cannot meaningfully reduce their winter heating usage, yet his solution is to lock in more of their costs within a fixed charge they cannot avoid if they are able to access LIURP or WAP. Far better tools to provide both stability and genuine affordability for low-income customers are: (1) expanded enrollment in CAP, which provides a bill tied to a customer's

ability to pay, and (2) for those not eligible for CAP, budget billing, which UGI is legally required to offer and which smooths payments without reducing the incentive to conserve.

Q: Mr. Taylor also argues that the proposed customer charge should not be scaled back proportionately if the Commission approves a lower revenue requirement because rate design should be based on cost to serve, not on the overall revenue level.[108] Do you agree?

A: No. While I understand the theoretical argument that rate design and revenue level are analytically distinct, the practical effect of approving the proposed $23.00 customer charge in the context of a lower overall revenue requirement is to lock in a structural shift toward fixed cost recovery. The Company is seeking a substantial revenue increase. If the Commission concludes that the requested increase is not fully justified, approving the full customer charge increase anyway compounds the harm to low-income and lower-use customers without the justification of a demonstrated need for that level of cost recovery.

Q: Has your recommendation about the customer charge changed?

A: No. My primary recommendation remains that no revenue increase is warranted and the customer charge should remain at $16.25. If the Commission awards any increase and continues the WNA, I do not oppose an increase in the monthly customer charge that is proportionately scaled to the revenue requirement authorized.

[108] UGI Statement No. 11-R at 29.

B. Weather Normalization Adjustment

Q: Mr. Taylor argues your analysis and the analysis of other witnesses about the WNA are incorrect, and that the WNA is a symmetrical, two-sided mechanism that benefits customers when weather is colder than normal, just as it protects the Company when weather is warmer than normal.[109] Do you agree?

A: While the WNA is mathematically bi-directional, the record demonstrates that in practice it has operated overwhelmingly to the financial detriment of customers. In my direct testimony, I provided evidence that since the WNA pilot began in November 2022 through February 2026, residential customers were surcharged a net total of approximately $44.2 million for gas service they did not actually use, based on UGI's calculation of what they would have used under "normal" weather.[110] UGI provided additional data for March and April 2026 that adds $4.1 million to the cumulative harm faced by its customers. This is shown in Table 4, below, which is the same as Table 12 in my direct except that it adds the months of March and April 2026.

Table 4: Net WNA charges to Residential Customers: November 2022- March 2026[111]

Year	WNA Revenue
2022	$1,797,324.60
2023	$24,315,727.00
2024	$30,472,835.86
2025	$1,766,165.42
Jan. 2026	($3,857,593.80)
Feb. 2026	($10,281,879.00)
Mar. 2026	$497,295.25
Apr. 2026	$3,613,166.60
Total	**$48,323,041.93**

[109] UGI Statement No. 11-R at 37.
[110] CAUSE-PA Statement No. 1 at 60, Table 12.
[111] UGI Response to CAUSE-PA 9-2, Attachment.

As currently constructed, the WNA is structurally more likely to generate net surcharges than net credits over its operating life, and customers — not shareholders — bear that risk. The mechanism is not truly symmetrical in its real-world impact as felt by consumers given that it has surcharged $48.3 million more than they otherwise would have paid since 2022.

Q: Mr. Taylor contends that the Company's proposal to switch to a rolling 10-year normal directly addresses concerns about the WNA producing imbalanced outcomes.[112] Does this change alleviate your concerns?

A: No. While I support the change to a 10-year normalization period if the WNA is to continue – and I acknowledge it will improve alignment of the normal weather used in ratemaking with the normal weather used in the WNA – it does not resolve my fundamental objection. My objection is not primarily about whether the WNA charges and credits are in balance over time; it is about whether it is appropriate for a monopoly provider of an essential service to shift weather-related revenue risk onto customers in the first place. The Company set its revenue requirement based on a fully projected future test year. It has access to financial tools and regulatory mechanisms – including the DSIC – to manage revenue uncertainty. Low income customers have none of these tools. They operate on tight monthly budgets with no margin to absorb unexpected surcharges based on energy they did not use, regardless of how well-calibrated the underlying normal may be. The 10-year update is a better design if the WNA exists, but it does not change who is bearing the risk, and that is the core problem.

[112] UGI Statement No. 11-R at 33-35.

Q: Mr. Taylor disagrees with you that the WNA is overly complicated and difficult to understand. He asserts that there are very few complaints about the WNA, which should be taken as proof that customers must understand the mechanism.[113] How do you respond?

A: The fact that UGI has received fewer complaints about the WNA is not an indication that consumers understand or accept the mechanism. I maintain the position that customers are not readily able to understand the complicated multi-variable algebraic equation that is necessary to calculate their WNA. Customers understand that they will be billed for what they use, they do not understand that they should be billed for what UGI has calculated they would have used had weather been consistent with normal.

Q: Mr. Taylor accuses you of making a strawman argument by pointing to his interrogatory response, where he stated that the WNA is not connected to UGI's ability to provide safe and reliable service, and then arguing that it really is only about maximizing revenue for the benefit of shareholders. How do you respond?

A: I merely relayed what Mr. Taylor stated in his interrogatory response. Here is the full question and answer:

[113] UGI Statement No. 11-R at 40-41.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to CAUSE-PA Set 4 (1-9)
Delivered on March 19, 2026

CAUSE-PA-4-7

Request:

If the Commission were to deny UGI's request to continue its WNA, please explain whether, in Mr. Taylor's opinion, the Company would be unable to provide safe and reliable service to its customers. If the answer to this question is yes, please explain in detail the basis for this response.

Response:

The question is based on the premise that the WNA is connected to the Company's ability to provide safe and reliable service. That premise is incorrect. The WNA is a rate design mechanism intended to address weather-related volatility in customer bills and distribution revenue recovery; it does not determine whether the Company can safely and reliably operate its system. The WNA provides the Company a reasonable opportunity to recover its allowed cost of service.

Prepared by or under the supervision of: John D. Taylor

My direct testimony merely pointed out that UGI has asserted no basis for its WNA that is rooted in its ability to provide safe and reliable service. While UGI's rebuttal is chock full of claims that it needs additional revenue to ensure that it can maintain its system, this is belied by the fact that at current rates it could make all of the investments that it is planning to make in capital and operating expenses and still projects to earn a return on equity of at least 7.7% as of September 30, 2027. The existence of the WNA only increases the likelihood that UGI will recover this level of revenue and, thus, is about its revenue not its ability to safely and reliably operate its system.

Q: Mr. Taylor disagrees with you that the WNA causes UGI to lose a significant incentive to operate efficiently because it cannot control for weather and it merely reduces a source of revenue volatility.[114] He also disagrees that it shifts weather-related risk to customers.[115] What is your response?

A: UGI is in the business of selling gas to people to heat their homes. The amount of gas that a person needs to heat their homes will vary depending on how hot or cold it is. Since the weather is warming – as evidenced by the $48 million in net WNA charges assessed to customers – and is projected to continue to warm[116] – UGI is seeking to shift the risk of its weather sensitive business that it has historically borne onto customers. This means that UGI has less concern about whether it will meet its revenue target, which creates incentives for UGI to be less efficient in its management as it otherwise would be. The fact that weather is an externality that UGI cannot control is immaterial. Customers cannot control the weather either. UGI has historically borne the risk of weather variation, and the WNA shifts that risk to customers. The fact of that matter is that through its WNA, UGI has shifted more than $48 million in weather-related risk onto its customers since 2022. As previously discussed, and as outlined more fully in my direct,[117] I believe this is inappropriate for a monopoly provider of an essential service and the WNA should be discontinued.

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[114] UGI Statement No. 11-R at 43.
[115] Id.
[116] See CAUSE-PA Statement No. 1 at 61, n116 (citing Pennsylvania Department of Environmental Protection, Pennsylvania Climate Impacts Assessment 2024 at 18 (finding that Pennsylvania's annual total heating degree days are anticipated to decrease by 13% by mid-century and 25% by end-of-century compared to the historical baseline).
[117] CAUSE-PA Statement No. 1 at 58-59.

Q: Mr. Taylor argues that exempting all confirmed low income customers from the WNA should not be permitted.[118] Did you make this argument?

A: No and to my knowledge no other witness made this argument in this case. I do not think that any customers should be assessed the WNA, and I support UGI's exclusion of CAP customers from the surcharge.

Q: Mr. Taylor argues that increasing the WNA deadband from 3% to 5% would materially weaken the mechanism and should be rejected.[119] How do you respond?

A: Widening the deadband to 5% would not eliminate the WNA's function. It would simply require more meaningful weather deviations before the mechanism activates, which is appropriate for a mechanism that charges customers for service they did not consume or credits customers for service that they did consume but should not have under normal weather. Mr. Taylor's objection that this is a "substantive narrowing"[120] is simply another way of saying it would reduce the frequency with which UGI collects revenue above the volumetric amounts actually billed — which is precisely the point given how overall one-directional the WNA has been historically. Furthermore, this wider deadband would be consistent with the Commission's recent decision in the 2025 Columbia rate case.[121]

[118] UGI Statement No. 11-R at 45.
[119] Id. at 46.
[120] Id.
[121] Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2024-3067174, Order at 202 (Order dated Dec. 4, 2025).

Q: Mr. Taylor defends applying the WNA during October and April, arguing that UGI's northern service territory experiences meaningful heating load in those months.[122] Should October and April remain months in which the WNA is charged?

A: No. While the northern part of UGI's service territory may experience meaningful heating load during those months, that fact is already embedded in UGI's rates and does not justify the imposition of the WNA in non-winter months. In my view, at an absolute minimum, October should be removed, consistent with the Commission's most recent decision in the Columbia Gas 2025 rate case. The Commission approved Columbia's WNA only for the months of November through April.

More broadly, I continue to recommend that the months during which the WNA is applied should be narrowed to December through March. These are the core winter heating months recognized by the Commission and the General Assembly for other public policy purposes, including the winter termination protections that apply to economically vulnerable households.[123] It is inconsistent with public policy to use those months as the benchmark for customer vulnerability in the termination context while simultaneously allowing UGI to assess weather-related surcharges on either side of that period.

Q: Have any of your overall recommendations regarding the WNA changed?

A: No. My primary recommendation remains that the Commission should allow the WNA to expire at the conclusion of the current pilot on October 31, 2027, as provided in UGI's current tariff. The WNA is a mechanism that transfers the financial risk of warming winters from a regulated monopoly utility — which is well-positioned to manage that risk

[122] UGI Statement No. 11-R at 47.
[123] See 52 Pa. Code § 56.100 (b) (Winter Termination Procedures for electric distribution and natural gas distribution utilities.).

— to low-income and fixed-income customers who are not. If the Commission concludes that some form of WNA is appropriate, it should be significantly reformed as outlined in my direct testimony.

VI. Tariff Changes

Q: Please describe your recommendations about UGI's Rule 9 regarding termination and discontinuance of service.

A: In my direct testimony, I reviewed UGI's Rule 9.1 (a), which provides a catchall with a mix of grounds for involuntary termination of service on "reasonable notice."[124] I explained that having theses listed under a catchall of "reasonable notice" does not adequately inform customers of their rights.[125] I recommended that UGI amend its tariff to separate out terminations that require notice and specify that at least ten days written notice is required.[126] I also recommended that UGI eliminate its tariff provision that allows it to generally terminate service for "violation of tariff Rules and Regulations," because it is overly broad and not authorized by existing PUC regulations of the Public Utility Code.[127]

Q: What was UGI's response to these recommendations?

A: UGI witness Daniel Adamo agrees with my recommendation to specify that certain involuntary terminations require 10-day notice.[128] However, he disagrees with my recommendation that UGI eliminate its tariff provision that allows it to generally terminate service for "violation of tariff Rules and Regulations."[129] He argues that "the Commission's

[124] CAUSE-PA Statement No. 1 at 91:15-93:32.
[125] Id. at 92:26-33.
[126] Id. at 92.
[127] Id.
[128] UGI Statement No. 13-R at 15.
[129] Id. at 16.

regulations do not function as an absolute limit on the grounds for which UGI Gas can terminate customers' service with notice."[130]

Q: What is your response?

A: I continue to disagree that UGI should be permitted to involuntarily terminate customers for grounds outside of those permitted by the Commission's regulations. Counsel will address this issue in briefing; however, the Commission's regulations provide an exhaustive list of permitted grounds for termination with notice.[131] UGI's tariff provision is far too wide-ranging and would permit it to terminate service with notice for any violation of its rules no matter how picayune that violation may be. I continue to stand by my recommendation that UGI should be limited to termination of service as authorized by Commission regulations and to update its tariff accordingly.

Q: Is there UGI rebuttal testimony addressing other witnesses to which you would like to respond?

A: Yes. UGI witness Jill Walter addresses OCA witness Barb Alexander's recommendation that Field Technicians performing residential termination of service should be trained to solicit or inquire about factors that would lead to suspending termination of service and whether door knocks should be required during terminations.[132] Ms. Walter argues that Field Technicians are responsible solely for physical service terminations and are not trained or suited to evaluate sensitive customer matters like income status or medical conditions.[133] She states that the company relies on

[130] Id. at 16:7.
[131] 52 Pa. Code § 56.81 et seq.
[132] UGI St. 3-R at 8.
[133] Id.

comprehensive written notifications to inform customers of their rights and protections.[134] She also points to UGI's Gatekeeper Program, which trains employees to recognize observable indicators of vulnerability (such as confusion, hoarding, or unsafe equipment) and refer them to an internal Outreach team.[135]

Q: What is your response?

A: I agree with Ms. Alexander and disagree with UGI's approach of requiring field technicians to rely strictly on "observable indicators," which introduces a dangerous element of subjectivity into a critical consumer protection process.

The Commission's regulation, colloquially known as the "Last Knock Rule," requires that, immediately prior to termination, the utility must attempt personal contact at the residence.[136] Ms. Walters asserts in her rebuttal testimony that field technicians are not trained or suited to evaluate sensitive customer matters like income status or medical conditions and should not solicit this information from customers.[137] This passive approach creates a substantial risk that vulnerable customers who do not exhibit obvious, visible signs of crisis will slip through the cracks. A standardized, direct question entirely removes the guesswork, ensuring that every customer facing termination is uniformly given the same opportunity to declare a qualifying medical or financial hardship.

Furthermore, refusing to ask a direct question about medical conditions and other factors under the guise of avoiding "half-evaluations" creates an unnecessary and inefficient bottleneck. A technician does not need advanced regulatory training to simply

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[134] UGI St. 3-R at 8-9.
[135] Id. at 8.
[136] 52 Pa Code § 56.94 (Procedures immediately prior to termination – "Immediately preceding the termination of service, a public utility employee, who may be the public utility employee designated to perform the termination, shall attempt to make personal contact with a responsible adult occupant at the residence of the customer.).
[137] UGI St. 3-R at 9.

record a "yes" or "no" response to a straightforward inquiry regarding medical or income status. By asking the question directly, the company secures an immediate, clear data point that can instantly trigger a pause in termination and a referral to the Outreach team. Far from escalating tension, a transparent, universal question demonstrates a standardized safety check, whereas a technician silently evaluating a customer's physical appearance or living conditions can feel profoundly invasive and arbitrary. Direct communication remains the most reliable mechanism to ensure customer safety and regulatory compliance.

VII. Recovery of Universal Service Costs

Q: Please summarize your direct testimony position on the recovery of universal service costs.

A: In my direct testimony, I addressed UGI's proposal to assign Universal Service and Energy Conservation program costs to Rate XD customers. I explained that the need for, and costs related to UGI's Universal Service and Energy Conservation programs are not solely "residential" problems and there is no rational basis for residential customers to solely bear the burden of these costs.[138] I proposed a broad reallocation of these costs to all customers classes to mitigate the cost impact to residential customers rather than continuing the current practice of assigning them solely to residential customers.[139]

[138] CAUSE-PA Statement No. 1 at 80-83.
[139] Id.

Q: Did other parties respond to your position in their rebuttal testimony?

A: Yes. OSBA witness Mark Ewen argues that small business customers should not contribute to universal service programs because these customers cannot take advantage of "residential-only" programs.[140]

He argues that there is no causal relationship between UGI's universal service costs and small business customers and that assigning costs for the universal service programs to all rate classes would impose a burden on OSBA to expend resources on experts to ensure that these programs are properly designed, effective, and necessary. He states that my proposal does not specify how universal service costs would be distributed within rate classes and would unfairly burden small businesses with a "new tax" without a cost basis. He recommends that, if the Commission decides to assign a portion of universals service costs to small businesses, the new charge should be separately identified on bills.[141]

Q: What is your response?

A: Mr. Ewen's argument rests on an outdated and narrow interpretation of utility cost causation. I outlined all the reasons why cross class universal service recovery is reasonable and appropriate in my direct testimony. The argument that small businesses receive no benefit from universal service programs ignores the fundamental economic realities outlined in my direct testimony that were unrebutted by Mr. Ewen. Thus, I stand by my analysis and data in my direct testimony, which demonstrate that all customer classes (including industry, business, commerce, educational institutions, hospitals, local

[140] OSBA Statement No. 1-R. Mr. Ewen's Rebuttal testimony does not have any page or line numbers. This quote appears on page 3 of 7 of the PDF circulated to the parties.
[141] Id. at page 4 of 7 of the PDF submitted by Mr. Ewen.

and state governments, and other residential customers) benefit from the availability and existence of universal service programs and assistance. It is a sound policy decision for all customers to share the costs of providing these programs to UGI's most vulnerable customers.[142]

VIII. Purchase of Receivable Program

Q: In direct testimony, you outlined how residential customers who were served by retail natural gas suppliers (NGS) paid $57.9 million between January 2023 and February 2026 more to receive service from NGSs than they would have otherwise paid had they been billed at default service rates.[143] You made a recommendation that UGI revise its POR program to require that to participate in POR and have UGI buy its receivables an NGS would have to certify that its rates are at or below the applicable default service price.[144] Did any party respond to your recommendation?

A: Only UGI. Ms. Rogers appears to agree with me that this is "an area where many customers are paying excessive costs that do not proceed any incremental benefits in safety or service quality."[145] However, she rejected by suggestion stating that "[i]t is not clear whether a single instance of a price about the PTC should result in exclusion from the POR program, and whether such an exclusion would be temporary . . . or permanent."[146] She further indicates that "the Company would need to evaluate the time and cost of any IT programming necessary to facilitate the structure of a modified POR

[142] Mr. Ewen also repeatedly refers to these costs as a "tax" perhaps for rhetorical effect. This, of course, is an incorrect framing as a private company cannot assess a tax and Universal Service rider costs are no more a tax than any other rate assessed by UGI.
[143] CAUSE-PA Statement No. 1 at 86-90.
[144] Id.
[145] UGI Statement No. 15-R at 33:6-8.
[146] Id. at 33:9-12.

program, which could be structurally difficult to administer if it moved suppliers on and off the POR program based on monthly variations in rates."[147]

Q: What is your response?

A: I appreciate that Ms. Rogers recognizes that concerns I addressed, but I object to her suggestion to delay addressing the acute harm to all ratepayers through inflated collections costs. My recommendation would be straightforward to implement. UGI could require that any NGS that wants to participate in POR must certify that the contracts the NGS offers residential customers are at or below the price to compare at the time the contract is entered or at any contract renewal. I am not proposing that the contract always must be less – given the quarterly fluctuations in the price to compare that may be difficult to administer. But it should not be difficult for UGI to change its supplier tariff to require this certification of all suppliers as a condition to participating in the POR. Any supplier who does not or cannot do so would still be permitted to dual bill, but would not have the privilege of participating in the POR. Regarding the question of timing and cost, I recommended that UGI implement this provision as of January 1, 2027, but if additional time is necessary to implement, I am open to a different date that would allow UGI the time needed to make these changes. In terms of cost, ratepayers should no longer bear the burden of paying the collections costs associated with supplier charges. As such, I recommend that POR-related costs should be tracked by UGI and assessed to participating POR suppliers through a discount on POR or a direct fee.

[147] UGI Statement No. 15-R at 33:12-15

IX. Conclusion

Q: Does this conclude your surrebuttal testimony?

A: Yes.

CAUSE-PA Statement 1-SR, Cicero

Appendix A

Exhibit Cicero 1-SR:

Shapiro Letter

Exhibit Cicero 2-SR:

Income $50k - $100k

within UGI Service Territory

Exhibit Cicero 3-SR:

CLI Arrears vs. Operation Share Budget

GOVERNOR JOSH SHAPIRO

April 29, 2026

Dear Utility Leaders:

As you are no doubt aware, many of your customers across the Commonwealth are experiencing markedly higher utility costs. Rising utility bills have themselves become drivers of inflation. While there are many factors affecting those increases, several core causes are directly within your control and result from your policy and fiscal decisions, including the excessive rate requests several utilities have sought in recent years. Last year alone, 13 Pennsylvania utilities requested $975 million in higher rates after those very same utilities had earned a total of $1.4 billion in profits in 2024.

We have reached a tipping point, and this is a moment to put your customers first and change the behaviors causing rate increases. As I've expressed publicly and privately, I believe the 20th century utility model is broken—we can no longer simply prioritize corporate profitability to drive infrastructure development. Rather, we must be laser focused on delivering on the actual needs of our communities. As I stated clearly in my Budget Address in February, Pennsylvania consumers should not be asked to pay a single dollar more than is needed to support a safe and reliable utility system.

Change is needed, and my Administration stands ready to support each Pennsylvania utility in raising the capital you need to invest in your service territories and workers, both in modernizing with cost-effective new technologies and maximizing the existing infrastructure that you have developed over time. However, as we work together to implement this new approach, you must seek to procure that capital in more affordable ways, conscious of the utility burdens facing many consumers across our Commonwealth.

I write today to lay out three commonsense practices to ensure the needs of Pennsylvanians come first. My Administration will use these three practices as a benchmark to evaluate rate case proposals going forward. Let me be clear: my Administration and I will vocally and forcefully oppose rate case requests from utilities that fail to adhere to these three commonsense practices.

First, utilities should seek to raise the most cost-effective forms of capital. Best practices now require you to protect consumers by disfavoring expensive equity when lower-cost debt is available. Given the low risk profile of monopolistic utilities, which maintain a captive rate base able to repay obligations over time, consumers should not be expected to bolster corporate profits through over reliance on costly equity. This means debt should normally represent a clear majority of a utility's proposed ratemaking capital structure, as it does in many other lower-risk industries. As one measure of this approach, any equity share proposed in a rate case in excess of the amount of equity employed by the utility's parent holding company will require extraordinary justification to receive my Administration's support.

For utilities looking to find low-cost sources of capital, my Administration encourages you to apply to the Department of Energy, which is currently offering loan terms as favorable as the 10-year U.S. Treasury yield plus 35 basis points. By comparison, the average Pennsylvania utility requested a return on equity a staggering 682 basis points above the 10-year U.S. Treasury yield last year. Before raising such expensive equity, you should take advantage of more affordable sources of capital, like these loans, that many of your fellow utilities across the country are pursuing. My Administration stands ready to facilitate an introduction to loan officers at the Department of Energy upon your request.

Second, whenever new revenue is sought, a utility must explain in plain, clear language why its proposed investments are necessary, using transparent data to identify a specific reliability or safety concern that will be addressed, or demonstrating with a thorough cost/benefit analysis that the investment will produce significant savings or reliability benefits for consumers. This means showing the value customers will receive in terms of discrete improvements producing tangible outcomes that are timebound, verifiable, and logically linked to the need for additional capital. Creating real value for customers also means maximizing existing grid resources in ways that control costs and defer the need for future upgrades. You must also describe explicitly what amount of your

requested rate increase will be remitted to shareholders through corporate dividends or other means, as compared to what would be used to directly advance the needs of your customers.

Third, you must provide transparent, justifiable equity returns. Pennsylvania has a long, proud tradition of trusting free markets to deliver fair, transparent pricing. In fact, this year marks the 30th anniversary of Act 138, which introduced competition into our utility sector for the first time. That bipartisan law embodies Pennsylvania's deep-seated belief that free-market competition—when properly implemented and overseen—is the best tool for delivering customers the fair value they deserve. Today, we use markets to price our wholesale power and rely on principles of competition to fairly and impartially award public contracts. Yet less accurate administrative determinations—essentially amounting to educated guesses—still govern how much utilities earn on their equity investment. And all too often the outcome of this administrative process is shrouded in "black box" settlements, that do not provide the public with transparency about costs they will have to pay. These vestiges of the past need to evolve to ensure that utilities are not seeking excessive profits but only the opportunity to earn the fair rate of return to which they are entitled.

To accomplish this, utilities can prove their need for a requested return on equity by providing a benchmark (representing at least 10% of the incremental requested equity) that is transparently derived through a public process with competitive bidding by multiple participants to establish a fair market cost of that equity. This sample offers the energy consumer and Public Utility Commission real-world evidence of the proper authorized return on equity, an amount that will allow the utility to earn reasonable equity returns under efficient operations. If a utility declines to justify its requested return on equity through a competitive, transparent process, it creates a presumption in the view of my Administration that the requested rate is higher than would have been derived from such a competitive process. Absent extraordinary and unforeseen circumstances, a utility can overcome that presumption by requesting a return on equity that does not exceed the rate of the current 10-year U.S. Treasury yield plus the five-year median of the equity risk premium as published in the Federal Reserve's Financial Stability Reports. In simple terms, this allows the filing utility to earn the same expected return as the stock market as a whole, according to Federal Reserve estimates, comfortably exceeding typical Public Utility Commission calculations of risk for the utility sector.

This provides an outcome that is fair for your utility and your customers even without an auction or other market-based price discovery mechanism.

This letter is an effort to be up front with you about my Administration's approach to rate requests going forward. In directly laying out these practices, I am making clear my expectations. I stand ready to collaborate with you, the Public Utility Commission, and other stakeholders in advancing thoughtful rate requests that put Pennsylvania families and businesses first and control costs after years of unacceptably high rate increases. Should you wish to have my Administration's support for any future rate requests, you must submit a description of your compliance with these practices to my Special Counsel for Energy Affordability alongside your rate case filings.

I appreciate your compliance with these practices and look forward to working together to control costs for ratepayers and build out the needed infrastructure for our Commonwealth.

Sincerely,

Governor Josh Shapiro

Cc: Honorable Stephen M. DeFrank, Chair, Pennsylvania Public Utility Commission
Honorable Kimberly M. Barrow, Vice Chair, Pennsylvania Public Utility Commission
Honorable Kathryn L. Zerfuss, Commissioner, Pennsylvania Public Utility Commission
Honorable John F. Coleman, Commissioner, Pennsylvania Public Utility Commission
Honorable Ralph V. Yanora, Commissioner, Pennsylvania Public Utility Commission
Mark Szybist, Special Counsel for Energy Affordability, Office of General Counsel

Households with income from $50,000 to $100,000 annually

County	Total*	$50,000 to $74,999*	$75,000 to $99,999*	Percentage $50k-$100k	Total $50k-$100k	UGI Residential Customers[1]	Estimated UGI $50k-$100k
Adams County	40,411.00	18.40%	14.10%	32.50%	13,134	41	13
Bedford County	19,763.00	17.30%	14.20%	31.50%	6,225	639	201
Berks County	161,701.00	16.70%	14.00%	30.70%	49,642	74,451	22,856
Blair County	50,548.00	17.20%	13.40%	30.60%	15,468	528	162
Bradford County	24,487.00	16.90%	12.90%	29.80%	7,297	3,782	1,127
Bucks County	247,674.00	13.00%	11.20%	24.20%	59,937	8,275	2,003
Carbon County	27,093.00	18.30%	13.40%	31.70%	8,588	2,955	937
Centre County	59,006.00	15.50%	11.70%	27.20%	16,050	272	74
Chester County	202,405.00	11.20%	11.40%	22.60%	45,744	3,074	695
Clarion County	14,982.00	19.00%	12.80%	31.80%	4,764	3,339	1,062
Clearfield County	32,089.00	19.70%	15.10%	34.80%	11,167	2,268	789
Clinton County	15,258.00	17.10%	12.60%	29.70%	4,532	2,492	740
Columbia County	25,874.00	16.80%	12.90%	29.70%	7,685	7,208	2,141
Cumberland County	105,187.00	17.00%	14.00%	31.00%	32,608	47,362	14,682
Dauphin County	119,763.00	17.80%	14.40%	32.20%	38,564	52,220	16,815
Forest County	1,944.00	22.80%	10.50%	33.30%	647	646	215
Franklin County	63,028.00	19.00%	15.30%	34.30%	21,619	3,986	1,367
Fulton County	6,156.00	17.30%	13.30%	30.60%	1,884	3	1
Huntingdon County	16,038.00	17.80%	15.10%	32.90%	5,277	1,375	452
Lackawanna County	88,266.00	16.50%	12.70%	29.20%	25,774	59,754	17,448
Lancaster County	210,536.00	17.40%	14.50%	31.90%	67,161	76,139	24,288
Lebanon County	55,846.00	16.60%	14.60%	31.20%	17,424	21,803	6,803
Lehigh County	143,445.00	16.40%	13.00%	29.40%	42,173	54,974	16,162
Luzerne County	133,434.00	17.50%	13.40%	30.90%	41,231	75,195	23,235
Lycoming County	46,201.00	19.50%	14.30%	33.80%	15,616	19,004	6,423
McKean County	16,204.00	20.30%	14.60%	34.90%	5,655	3,747	1,308
Mifflin County	18,502.00	22.00%	15.30%	37.30%	6,901	2,667	995
Monroe County	60,562.00	15.50%	13.00%	28.50%	17,260	3,868	1,102
Montgomery County	333,514.00	12.30%	11.40%	23.70%	79,043	3,590	851
Montour County	7,689.00	16.30%	12.40%	28.70%	2,207	2,112	606
Northampton County	121,496.00	15.40%	13.20%	28.60%	34,748	54,468	15,578
Northumberland County	37,581.00	18.30%	13.10%	31.40%	11,800	11,682	3,668
Pike County	24,009.00	19.40%	15.50%	34.90%	8,379	1,045	365
Potter County	6,757.00	19.50%	13.90%	33.40%	2,257	5,899	1,970
Schuylkill County	57,465.00	18.80%	14.80%	33.60%	19,308	3,379	1,135
Snyder County	14,549.00	18.60%	15.20%	33.80%	4,918	2,068	699
Susquehanna County	15,639.00	18.20%	14.00%	32.20%	5,036	346	111
Tioga County	16,639.00	19.70%	13.80%	33.50%	5,574	13,064	4,376
Union County	14,301.00	16.00%	13.60%	29.60%	4,233	1,710	506
Venango County	21,342.00	18.60%	13.30%	31.90%	6,808	883	282
Wayne County	20,314.00	19.00%	15.00%	34.00%	6,907	2,264	770
Wyoming County	10,892.00	18.00%	14.80%	32.80%	3,573	388	127
York County	180,207.00	16.80%	14.80%	31.60%	56,945	1,581	500
Total Census	**2,888,797.00**			**29.14%**	**841,760**		
Total UGI				30.73%		**636,505**	**195,628**

Source: * U.S. Census Bureau, U.S. Department of Commerce. "Income in the Past 12 Months (in 2023 Inflation-Adjusted Dollars)." American Community Survey, ACS 5-Year Estimates Subject Tables, Table S1901, https://data.census.gov/table/ACSST5Y2023.S1901?t=Income+and+Poverty&g=040XX00US42$0500000_050XX00US42117. Accessed on 19 May 2026.

[1] UGI Response to CAUSE-PA 1-8

UGI Confirmed Low Income Arrears vs Operation Share Funding and Grants Awarded Oct 2023-Jan 2026

Year	Month	CLI_Arrears [1]	Grant_Available [2]	Grant_Total [3]
2024	January	$23,983,808	$762,539	$61,817
2024	February	$25,838,017	$671,456	$91,083
2024	March	$26,743,918	$600,052	$71,404
2024	April	$26,265,781	$556,133	$58,920
2024	May	$25,453,497	$525,913	$30,220
2024	June	$24,326,741	$527,966	$51,129
2024	July	$22,632,828	$491,946	$36,021
2024	August	$21,821,584	$472,074	$21,477
2024	September	$21,166,541	$453,787	$18,286
2024	October	$21,083,849	$905,984	$132,309
2024	November	$21,503,332	$846,976	$59,008
2024	December	$23,537,624	$810,345	$36,631
2024	**Average Arrears v. Average Grant Available**	**$23,696,460**	**$635,431**	
2024	**Total Grants Awarded**			**$668,305**
2025	January	$26,751,742	$744,920	$66,936
2025	February	$29,619,655	$663,631	$84,970
2025	March	$31,904,200	$569,177	$89,404
2025	April	$33,214,167	$486,778	$82,399
2025	May	$32,644,097	$459,527	$61,976
2025	June	$31,457,452	$428,085	$31,442
2025	July	$29,588,319	$411,747	$16,338
2025	August	$28,088,160	$393,933	$17,815
2025	September	$27,390,545	$381,499	$12,436
2025	October	$28,659,933	$1,315,726	$150,143
2025	November	$29,748,354	$1,193,369	$561,857
2025	December	$32,594,802	$978,476	$214,892
2025	**Average Arrears v. Average Grant Available**	**$30,138,452**	**$668,906**	
2025	**Total Grants Awarded**			**$1,390,608**

Source

[1] CAUSE-PA to UGI 1-22 (C)

[2]CAUSE-PA to UGI 2-17 (C)

[3] CAUSE-PA to UGI 2-17 (B)

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523, et al.
	:	
UGI Utilities, Inc. - Gas Division	:	

PREPARED HEARING EXHIBIT LIST OF THE COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA

The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA) intends to move for admission of the following evidence at the June 2-4, 2026, evidentiary hearings in the above-captioned matter:

- Direct Testimony of Patrick M. Cicero on Behalf of The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), CAUSE-PA Statement 1 (As Corrected by Erratum and Further Corrected at the June 2, 2026 Evidentiary Hearing).
  - 93 pages of written testimony
  - Appendix A: Resume, Patrick Cicero
  - Appendix B: Cited Discovery Responses
  - Appendix C: Exhibits Cicero C-1 through C-6

- Surrebuttal Testimony of Patrick M. Cicero on Behalf of The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), CAUSE-PA Statement 1-SR
  - 50 pages of written testimony
  - Appendix A: Exhibits Cicero 1-SR through 3-SR

- Verification of Patrick M. Cicero to CAUSE-PA Statement 1 and CAUSE-PA Statement 1-SR

Respectfully Submitted,
PENNSYLVANIA UTILITY LAW PROJECT
Counsel for CAUSE-PA

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Dated: June 2, 2026